June 3, 2025

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

Re: MPSC Case No. U-21806 – In the matter of the application of Consumers Energy Company for authority to increase its rates for the distribution of natural gas and for other relief.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find the **Redacted Official Exhibits of Consumers Energy Company**. The Confidential Official Exhibits will be filed under seal with the Executive Secretary.

This is a paperless filing and is therefore being filed only in PDF. Also included is a Proof of Service showing electronic service upon the parties.

Sincerely,

Digitally signed by Anne M. Uitvlugt
Date: 2025.06.03 09:35:15 -04'00'

Anne M. Uitvlugt
Phone: 517-788-2112
Email: anne.uitvlugt@cmsenergy.com

cc: Parties to Attachment 1 to the Proof of Service

Schedule: A-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Revenue Deficiency (Sufficiency)
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-1 (HLR-1)
Schedule: A-1
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Rate base	Exhibit No.: A-2 (HLR-3)	9,479,241
2	Adjusted net operating income	Exhibit No.: A-3 (HLR-9)	561,724
3	Overall rate of return	Line 2 / Line 1	5.93%
4	Required rate of return	Exhibit No.: A-4 (HLR-23)	5.85%
5	Income requirements	Line 4 * Line 1	554,667
6	Income deficiency (sufficiency)	Line 5 - Line 2	(7,057)
7	Revenue conversion factor	Exhibit No.: A-3 (HLR-10)	1.3381
8	Revenue deficiency (sufficiency)	Line 6 * Line 7	(9,443)

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Financial Basis
GAS RESULTS ONLY
($000)

Case No.: U-21806
Exhibit No.: A-1 (HLR-2)
Schedule: A-2

Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) 2019	(c) 2020	(d) 2021	(e) 2022	(f) 2023
		Calendar Year				
1	Operating revenues	1,937,244	1,817,085	2,063,507	2,732,332	2,420,332
2	Operating expenses	1,612,200	1,436,050	1,688,449	2,286,056	1,922,097
3	Pre-tax operating income	325,044	381,035	375,058	446,276	498,235
4	Income taxes	50,920	57,937	39,252	31,621	97,951
5	Net operating income	274,124	323,098	335,805	414,655	400,284
6	Other income and deductions	37,466	39,831	68,531	78,033	72,246
7	AFUDC	7,983	804	2,725	2,007	5,808
8	Interest charges	(85,774)	(102,531)	(104,642)	(116,431)	(162,571)
9	Preferred stock dividends	(482)	(565)	(596)	(598)	(635)
10	Net income available to common stockholders	233,318	260,638	301,824	377,666	315,132
11	Average common equity	2,124,595	2,397,825	2,652,186	3,485,506	3,860,295
12	Earned rate of return on common equity	10.98%	10.87%	11.38%	10.84%	8.16%
13	Authorized rate of return on common equity	10.00% {1}	9.90% {2}	9.90% {2}	9.90% {3}	9.90% {4}

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Financial Basis
GAS RESULTS ONLY
($000)

Case No.: U-21806
Exhibit No.: A-1 (HLR-2)
Schedule: A-2

Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) 2019	(c) 2020	(d) 2021	(e) 2022	(f) 2023
				Calendar Year		
	EBIT Interest Coverage Ratio					
14	Pre-tax operating income	325,044	381,035	375,058	446,276	498,235
15	Other income and deductions	37,466	39,831	68,531	78,033	72,246
16	AFUDC	7,983	804	2,725	2,007	5,808
17	Total EBIT	370,493	421,670	446,314	526,316	576,289
18	Interest charges	85,774	102,531	104,642	116,431	162,571
19	EBIT interest coverage ratio	4.32	4.11	4.27	4.52	3.54
	EBITDA Interest Coverage Ratio					
20	Total EBIT	370,493	421,670	446,314	526,316	576,289
21	Depreciation and amortization	261,205	282,447	304,101	329,281	337,716
22	Total EBITDA	631,698	704,117	750,415	855,597	914,005
23	Interest charges	85,774	102,531	104,642	116,431	162,571
24	EBITDA interest coverage ratio	7.36	6.87	7.17	7.35	5.62
	Funds Flow from Operations (FFO) Interest Coverage Ratio					
25	Net operating income	274,124	323,098	335,805	414,655	400,284
26	Depreciation and amortization	261,205	282,447	304,101	329,281	337,716
27	Deferred income taxes	9,149	35,229	15,474	36,367	94,463
28	AFUDC	7,983	804	2,725	2,007	5,808
29	Other major recurring non-cash items	-	-	-	-	-
30	Interest paid	77,811	97,469	99,352	106,720	149,285
	Less:					
31	Operating lease adjustment to depreciation	-	-	-	-	-
32	Subtotal	630,272	739,047	757,457	889,030	987,556
33	Interest charges	85,774	102,531	104,642	116,431	162,571
34	FFO interest coverage ratio	7.35	7.21	7.24	7.64	6.07

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Financial Basis
GAS RESULTS ONLY
($000)

Case No.: U-21806
Exhibit No.: A-1 (HLR-2)
Schedule: A-2
Page: 3 of 6
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) 2019	(c) 2020	(d) 2021	(e) 2022	(f) 2023
				Calendar Year		
	Overall Fixed Charge Coverage Ratio					
35	Net income available to common stockholders	233,318	260,638	301,824	377,666	315,132
36	Interest charges	85,774	102,531	104,642	116,431	162,571
37	Subtotal numerator	319,092	363,169	406,465	494,097	477,702
38	Interest charges	85,774	102,531	104,642	116,431	162,571
39	Preferred stock dividends	482	565	596	598	635
40	Subtotal denominator	86,256	103,095	105,238	117,029	163,206
41	Overall fixed charge coverage ratio	3.70	3.52	3.86	4.22	2.93
	Cash Flow Coverage of Dividends Ratio					
42	Net income available to common stockholders	233,318	260,638	301,824	377,666	315,132
43	Depreciation and amortization	261,205	282,447	304,101	329,281	337,716
44	Deferred income taxes	9,149	35,229	15,474	36,367	94,463
45	Subtotal	503,672	578,314	621,398	743,314	747,311
46	Common dividends {5}	186,655	208,510	241,459	302,133	252,105
47	Cash flow coverage of dividends ratio	2.70	2.77	2.57	2.46	2.96
	Common Dividend Payout Ratio					
48	Common dividends {5}	186,655	208,510	241,459	302,133	252,105
49	Net income available to common stockholders	233,318	260,638	301,824	377,666	315,132
50	Common dividend payout ratio	80%	80%	80%	80%	80%
	Permanent Capitalization					
51	Long term debt	7,263,181	8,131,338	8,437,664	10,208,351	11,160,087
52	Preferred stock	37,315	37,315	37,315	37,315	37,315
53	Common equity	7,700,854	8,519,584	9,242,745	10,118,365	10,763,382
54	Total permanent capital	15,001,350	16,688,236	17,717,724	20,364,031	21,960,785
55	Long term debt	48.42%	48.72%	47.62%	50.13%	50.82%
56	Preferred stock	0.25%	0.22%	0.21%	0.18%	0.17%
57	Common equity	51.33%	51.05%	52.17%	49.69%	49.01%
58	Total permanent capital	100.00%	100.00%	100.00%	100.00%	100.00%

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Ratemaking Basis
GAS RESULTS ONLY
($000)

Case No.: U-21806
Exhibit No.: A-1 (HLR-2)
Schedule: A-2

Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) 2019	(c) 2020	(d) 2021	(e) 2022	(f) 2023
		Calendar Year				
59	Operating revenues	1,925,857	1,802,875	2,041,152	2,715,535	2,399,920
60	Operating expenses	1,591,378	1,397,637	1,633,461	2,196,076	1,852,976
61	Pre-tax operating income	334,479	405,238	407,692	519,459	546,945
62	Income taxes	24,034	39,960	18,306	6,303	73,864
63	Net operating income	310,445	365,278	389,385	513,156	473,080
64	Tax impact of pro forma interest on NOI	1,409	(1,118)	94	1,290	(611)
65	AFUDC	7,983	804	2,725	2,007	5,808
66	Interest charges	(91,338)	(98,115)	(104,863)	(121,339)	(159,910)
67	Preferred stock dividends	(580)	(577)	(613)	(637)	(635)
68	Net income available to common stockholders and JDITC	227,919	266,273	286,728	394,477	317,733
69	Return assignable to JDITC	(1,987)	(2,060)	(2,159)	(2,514)	(2,423)
70	Net income available to common stockholders	225,932	264,213	284,569	391,963	315,309
71	Average common equity	2,570,557	2,830,883	3,268,716	3,748,368	3,956,553
72	Earned rate of return on common equity	8.79%	9.33%	8.71%	10.46%	7.97%
73	Net income effect of normalized weather	(15,481)	37,702	52,221	(18,871)	83,446
74	Net income available to common stockholders, weather adjuste	210,451	301,914	336,790	373,092	398,756
75	Earned return on equity, weather adjusted	8.19%	10.67%	10.30%	9.95%	10.08%
76	Authorized return on equity	10.00% {1}	9.90% {2}	9.90% {2}	9.90% {3}	9.90% {4}

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Ratemaking Basis
GAS RESULTS ONLY
($000)

Case No.: U-21806
Exhibit No.: A-1 (HLR-2)
Schedule: A-2
Page: 5 of 6
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) 2019	(c) 2020	(d) 2021	(e) 2022	(f) 2023
				Calendar Year		
	EBIT Interest Coverage Ratio					
77	Pre-tax operating income	334,479	405,238	407,692	519,459	546,945
78	AFUDC	7,983	804	2,725	2,007	5,808
79	Total EBIT	342,462	406,043	410,417	521,465	552,753
80	Interest charges, net of pro forma interest	92,747	96,996	104,957	122,629	159,299
81	EBIT interest coverage ratio	3.69	4.19	3.91	4.25	3.47
	EBITDA Interest Coverage Ratio					
82	Total EBIT	342,462	406,043	410,417	521,465	552,753
83	Depreciation and amortization	268,649	291,550	313,763	338,116	345,988
84	Total EBITDA	611,111	697,593	724,180	859,581	898,740
85	Interest charges, net of pro forma interest	92,747	96,996	104,957	122,629	159,299
86	EBITDA interest coverage ratio	6.59	7.19	6.90	7.01	5.64
	Funds Flow from Operations (FFO) Interest Coverage Ratio					
87	Net operating income	310,445	365,278	389,385	513,156	473,080
88	Depreciation and amortization	268,649	291,550	313,763	338,116	345,988
89	Deferred income tax	9,149	35,229	15,474	36,367	94,463
90	AFUDC	7,983	804	2,725	2,007	5,808
91	Other major recurring non-cash items	-	-	-	-	-
92	Interest paid	77,811	97,469	99,352	106,720	149,285
	Less:					
93	Operating lease adjustment to depreciation	-	-	-	-	-
94	Subtotal	674,037	790,330	820,699	996,365	1,068,624
95	Interest charges, net of pro forma interest	92,747	96,996	104,957	122,629	159,299
96	FFO interest coverage ratio	7.27	8.15	7.82	8.13	6.71
	Overall Fixed Charge Coverage Ratio					
97	Net income available to common stockholders	225,932	264,213	284,569	391,963	315,309
98	Interest charges, net of pro forma interest	92,747	96,996	104,957	122,629	159,299
99	Subtotal numerator	318,680	361,209	389,526	514,592	474,608
100	Interest charges, net of pro forma interest	92,747	96,996	104,957	122,629	159,299
101	Preferred stock dividends	580	577	613	637	635
102	Subtotal denominator	93,328	97,573	105,569	123,266	159,933
103	Overall fixed charge coverage ratio	3.41	3.70	3.69	4.17	2.97

Schedule A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Ratemaking Basis
GAS RESULTS ONLY
($000)

Case No.: U-21806
Exhibit No.: A-1 (HLR-2)
Schedule: A-2
Page: 6 of 6
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) 2019	(c) 2020	(d) 2021	(e) 2022	(f) 2023
				Calendar Year		
	Cash Flow Coverage of Dividends Ratio					
104	Net income available to common stockholders	225,932	264,213	284,569	391,963	315,309
105	Depreciation and amortization	268,649	291,550	313,763	338,116	345,988
106	Deferred income tax	9,149	35,229	15,474	36,367	94,463
107	Subtotal	503,730	590,992	613,806	766,446	755,760
108	Common dividends {5}	180,746	211,370	227,655	313,570	252,247
109	Cash flow coverage of dividends ratio	2.79	2.80	2.70	2.44	3.00
	Common Dividend Payout Ratio					
110	Common dividends {5}	180,746	211,370	227,655	313,570	252,247
111	Net income available to common stockholders	225,932	264,213	284,569	391,963	315,309
112	Common dividend payout ratio	80%	80%	80%	80%	80%
	Permanent Capitalization					
113	Long term debt, excluding securitization	6,997,291	7,880,109	8,214,999	9,009,833	10,397,193
114	Preferred stock	37,315	37,315	37,315	37,315	37,315
115	Common equity	7,728,910	8,555,596	9,274,520	10,133,854	10,778,709
116	Total permanent capital	14,763,516	16,473,020	17,526,834	19,181,001	21,213,217
117	Long term debt, excluding securitization	47.40%	47.84%	46.87%	46.97%	49.01%
118	Preferred stock	0.25%	0.23%	0.21%	0.19%	0.18%
119	Common equity	52.35%	51.94%	52.92%	52.83%	50.81%

{1} Case No. U-20322 final order dated 09/26/2019; effective 10/01/2019
{2} Case No. U-20650 settlement agreement dated 09/10/2020; effective 10/01/2020
{3} Case No. U-21148 settlement agreement dated 07/07/2022; effective 10/01/2022
{4} Case No. U-21308 settlement agreement dated 08/30/2023; effective 10/01/2023
{5} CECo pays dividends to the parent as a total company. This number represents the company's 80% dividend policy applied to net income available to common stockholders

Schedule: B-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Rate Base
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-2 (HLR-3)
Schedule: B-1
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Total utility plant	Exhibit No.: A-2 (HLR-4)	12,024,225
2	Depreciation reserve	Exhibit No.: A-2 (HLR-5)	(4,015,184)
3	Customer advances for construction	Exhibit No.: A-2 (HLR-7), Column (e.2), Line 29	(34,956)
4	Net utility plant	Sum of Lines 1 through 3	7,974,085
5	Net unamortized manufactured gas plant	Exhibit No.: A-2 (HLR-7), Column (e.3), Line 36	41,147
6	Utility plant rate base	Line 4 + Line 5	8,015,232
7	Working capital	Exhibit No.: A-2 (HLR-6)	1,464,009
8	Total rate base	Line 6 + Line 7	9,479,241

Schedule: B-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Total Utility Plant
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-2 (HLR-4)
Schedule: B-2
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) FERC Account Number	(c) Source	(d) Amount
1	Total plant-in-service	101	Exhibit No.: A-2 (HLR-7), Column (e.2), Line 3 - Line 4	11,635,511
2	Plant held for future use		WP-HLR-6, Utility Plant Tab, Acct 1051000	1
3	Plant held for future use - common		WP-HLR-6, Common Plant Tab, Acct 1052000	-
4	Total plant held for future use	105	Line 2 + Line 3	1
5	Construction work in progress	107	Exhibit No.: A-2 (HLR-7), Column (e.2), Line 7	388,713
6	Total utility plant		Line 1 + Line 4 + Line 5	12,024,225

Schedule: B-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Depreciation Reserve and Other Deductions
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-2 (HLR-5)
Schedule: B-3
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Utility plant accumulated depreciation	Exhibit No.: A-2 (HLR-7), Column (e.2), Line 4	(2,394,506)
2	Common plant accumulated depreciation	Exhibit No.: A-2 (HLR-7), Column (e.2), Line 5	(329,706)
3	Cost of removal - regulatory liabilities	WP-HLR-6, Def. CR Tab, Acct 2800000	(2,389)
4	Cost of removal - gas regulatory liabilities	WP-HLR-6, Def. CR Tab, Acct 2802000	(1,288,584)
5	Total depreciation reserve and other deductions	Sum of Lines 1 through 4	(4,015,184)

Schedule: B-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Working Capital
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-2 (HLR-6)
Schedule: B-4
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Cash, cash equivalents, and restricted cash	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 10	8,652
2	Accounts and notes receivable	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 11	136,699
3	Fuel stock	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 12	-
4	Materials and supplies	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 13	53,954
5	Allowances	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 14	-
6	Gas stored underground	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 15	625,469
7	Prepayments	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 16	503,604
8	Accrued revenue	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 17	155,225
9	Deferred taxes	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 18	173,309
10	Deferred debits	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 19	310,739
11	Total assets	Sum of Lines 1 through 10	1,967,652
12	Debt, leases, and financial obligations	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 21	-
13	Notes payable	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 22	-
14	Accounts payable	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 23	263,574
15	Customer deposits	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 24	13,128
16	Accrued interest	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 25	38,112
17	Dividends payable	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 26	11,903
18	Accrued taxes	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 27	140,181
19	Other liabilities	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 28	26,309
20	Customer advances	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 29	-
21	Deferred income and investment taxes	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 30	-
22	Deferred credits	Exhibit No.: A-2 (HLR-7), Column (f.2), Line 31	10,437
23	Total liabilities	Sum of Lines 12 through 22	503,643
24	Total working capital	Line 11 - Line 23	1,464,009

Schedule: B-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
13-Month Average Balance Sheet
For the Historical Year Ended December 31, 2023
(In Dollars)

Case No.: U-21806
Exhibit No.: A-2 (HLR-7)
Schedule: B-5
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Source: WP-HLR-6

	(a)	(b)	(c.1)	(c.2)	(d.1)	(d.2)	(d.3)	(d.4)	(d.5)	(e.1)	(e.2)	(e.3)	(e.4)	(f.1)	(f.2)	(f.3)
			EXCLUDED		CAPITAL STRUCTURE					PLANT				WORKING CAPITAL		
Line No.	Description	Total	Rate Base	Sub. Invest.	LT Debt	ST Debt	ITC	Deferred Tax	Equity	Electric	Gas	MGP	Non-Utility	Electric	Gas	Non-Utility
1	Utility plant	$ 31,104,121,228	$ 991,401,896	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,012,535,257	$ 11,100,184,075	$ -	$ -	$ -	$ -	$ -
2	Common plant	1,385,750,906	9,382,643	-	-	-	-	-	-	841,040,438	535,327,825	-	-	-	-	-
3	Gross plant	32,489,872,134	1,000,784,540	-	-	-	-	-	-	19,853,575,694	11,635,511,900	-	-	-	-	-
4	Utility plant accumulated depreciation	(8,110,414,237)	(480,477,398)	-	-	-	-	-	-	(5,235,431,006)	(2,394,505,833)	-	-	-	-	-
5	Common plant accumulated depreciation	(878,982,194)	(5,898,146)	-	-	-	-	-	-	(543,378,223)	(329,705,824)	-	-	-	-	-
6	Total depreciation	(8,989,396,431)	(486,375,544)	-	-	-	-	-	-	(5,778,809,229)	(2,724,211,657)	-	-			
7	Construction work in progress	1,075,660,807	-	-	-	-	-	-	-	686,947,696	388,713,111	-	-	-	-	-
8	Net plant	24,576,136,510	514,408,995	-	-	-	-	-	-	14,761,714,161	9,300,013,353	-	-	-	-	-
9	Other property	160,100,868	118,579,665	(6,992,608)	-	-	-	-	-	-	-	-	27,025,679	-	-	21,488,133
10	Cash, cash equivalents, and restricted cash	117,858,100	90,570,746	-	-	-	-	-	-	-	-	-	-	18,634,895	8,652,458	-
11	Accounts and notes receivable	448,795,214	19,092,644	-	-	-	-	-	-	-	-	-	-	284,547,363	136,698,517	8,456,690
12	Fuel stock	69,271,687	-	-	-	-	-	-	-	-	-	-	-	69,271,687	-	-
13	Materials and supplies	232,762,662	21	-	-	-	-	-	-	-	-	-	-	178,808,418	53,954,223	-
14	Allowances	10,626,941	10,612,653	-	-	-	-	-	-	-	-	-	-	14,288	-	-
15	Gas stored underground	625,468,897	-	-	-	-	-	-	-	-	-	-	-	-	625,468,897	-
16	Prepayments	1,293,420,949	5,570,637	-	-	-	-	-	-	-	-	-	-	784,246,379	503,603,933	-
17	Accrued revenue	505,830,477	68,307,843	-	-	-	-	-	-	-	-	-	-	282,297,291	155,225,342	-
18	Deferred taxes	2,256,111,671	(14,210,462)	-	-	-	-	1,848,639,429	-	-	-	-	-	248,045,357	173,309,480	327,868
19	Deferred debits	2,133,160,629	885,130,410	-	75,396,296	-	-	-	-	-	-	103,731,414	-	757,895,388	310,739,218	267,902
20	Total assets	32,429,544,603	1,698,063,152	(6,992,608)	75,396,296	-		1,848,639,429	-	14,761,714,161	9,300,013,353	103,731,414	27,025,679	2,623,761,066	1,967,652,069	30,540,592
21	Debt, leases, and financial obligations	(10,400,239,406)	(74,037,157)	-	(10,210,817,634)	(115,384,615)	-	-	-	-	-	-	-	-	-	-
22	Notes payable	(328,057,104)	(193,325,675)	-	-	(134,731,429)	-	-	-	-	-	-	-	-	-	-
23	Accounts payable	(720,726,916)	(2,565,154)	-	-	-	-	-	-	-	-	-	-	(451,895,938)	(263,573,603)	(2,692,222)
24	Customer deposits	(35,403,498)	-	-	-	-	-	-	-	-	-	-	-	(22,275,354)	(13,128,143)	-
25	Accrued interest	(102,880,306)	(1,975,794)	-	-	-	-	-	-	-	-	-	-	(62,520,436)	(38,111,634)	(272,442)
26	Dividends payable	(31,513,782)	-	-	-	-	-	-	-	-	-	-	-	(19,525,939)	(11,902,755)	(85,087)
27	Accrued taxes	(342,660,075)	-	-	-	-	-	-	-	-	-	-	-	(202,203,876)	(140,180,507)	(275,693)
28	Other liabilities	(253,049,156)	(160,440,640)	-	-	-	-	-	-	-	-	(3,499,613)	-	(62,800,009)	(26,308,895)	-
29	Customer advances	(95,721,750)	-	-	-	-	-	-	-	(60,766,006)	(34,955,744)	-	-	-	-	-
30	Deferred income and investment taxes	(5,993,752,980)	6,586,012	-	-	-	(127,506,487)	(5,872,832,506)	-	-	-	-	-	-	-	-
31	Deferred credits	(3,633,282,026)	(925,796,472)	-	-	(40,027,810)		-	-	(1,211,729,332)	(1,290,972,582)	(59,084,687)	-	(93,358,311)	(10,437,254)	(1,875,577)
32	Total liabilities	(21,937,287,000)	(1,351,554,880)	-	(10,210,817,634)	(290,143,854)	(127,506,487)	(5,872,832,506)	-	(1,272,495,338)	(1,325,928,326)	(62,584,300)	-	(914,579,863)	(503,642,791)	(5,201,021)
33	Common equity	(10,454,942,804)	15,205,579	-	-	-	-	-	(10,470,148,382)	-	-	-	-	-	-	-
34	Preferred stock	(37,314,800)	-	-	-	-	-	-	(37,314,800)	-	-	-	-	-	-	-
35	Total equity	(10,492,257,604)	15,205,579	-	-	-	-	-	(10,507,463,182)	-	-	-	-	-	-	-
36	Net assets	$ -	$ 361,713,851	$ (6,992,608)	$ (10,135,421,338)	$ (290,143,854)	$ (127,506,487)	$ (4,024,193,077)	$ (10,507,463,182)	$ 13,489,218,823	$ 7,974,085,027	$ 41,147,115	$ 27,025,679	$ 1,709,181,203	$ 1,464,009,278	$ 25,339,571

Schedule: B-6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Point-In-Time Balance Sheet
For the Historical Year Ended December 31, 2023
(In Dollars)

Case No.: U-21806
Exhibit No.: A-2 (HLR-8)
Schedule: B-6
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Source: WP-HLR-5

(a)	(b)	(c.1)	(c.2)	(d.1)	(d.2)	(d.3)	(d.4)	(d.5)	(e.1)	(e.2)	(e.3)	(e.4)	(f.1)	(f.2)	(f.3)
Line		EXCLUDED		CAPITAL STRUCTURE					PLANT				WORKING CAPITAL		
No. Description	Total	Rate Base	Sub. Invest.	LT Debt	ST Debt	ITC	Deferred Tax	Equity	Electric	Gas	MGP	Non-Utility	Electric	Gas	Non-Utility
1 Utility plant	$ 32,021,666,869	$ 685,217,059	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,688,564,742	$ 11,647,885,068	$ -	$ -	$ -	$ -	$ -
2 Common plant	1,335,814,975	8,753,624	-	-	-	-	-	-	811,044,718	516,016,632	-	-	-	-	-
3 Gross plant	33,357,481,844	693,970,684	-	-	-	-	-	-	20,499,609,460	12,163,901,700	-	-	-	-	-
4 Utility plant accumulated depreciation	(8,348,026,112)	(200,514,312)	-	-	-	-	-	-	(5,690,787,132)	(2,456,724,669)	-	-	-	-	-
5 Common plant accumulated depreciation	(825,173,483)	(6,046,353)	-	-	-	-	-	-	(509,807,413)	(309,319,717)	-	-	-	-	-
6 Total depreciation	(9,173,199,596)	(206,560,665)	-	-	-	-	-	-	(6,200,594,545)	(2,766,044,386)	-	-			
7 Construction work in progress	837,572,765	-	-	-	-	-	-	-	511,897,502	325,675,263	-	-	-	-	-
8 Net plant	25,021,855,013	487,410,018	-	-	-	-	-	-	14,810,912,417	9,723,532,578	-	-	-	-	-
9 Other property	162,369,315	119,280,427	(6,985,986)	-	-	-	-	-	-	-	-	25,605,202	-	-	24,469,671
10 Cash, cash equivalents, and restricted cash	35,869,765	2,899,284	-	-	-	-	-	-	-	-	-	-	22,515,978	10,454,503	-
11 Accounts and notes receivable	454,817,965	43,633,024	-	-	-	-	-	-	-	-	-	-	270,179,404	131,011,007	9,994,531
12 Fuel stock	79,873,395	-	-	-	-	-	-	-	-	-	-	-	79,873,395	-	-
13 Materials and supplies	257,016,136	21	-	-	-	-	-	-	-	-	-	-	200,546,215	56,469,901	-
14 Allowances	9,725,263	9,710,975	-	-	-	-	-	-	-	-	-	-	14,288	-	-
15 Gas stored underground	586,598,473	-	-	-	-	-	-	-	-	-	-	-	-	586,598,473	-
16 Prepayments	1,439,316,972	5,570,637	-	-	-	-	-	-	-	-	-	-	864,273,192	569,473,143	-
17 Accrued revenue	498,555,841	3,504,668	-	-	-	-	-	-	-	-	-	-	293,174,077	201,877,096	-
18 Deferred taxes	2,484,150,124	5,379,000	-	-	-	-	1,827,076,518	-	-	-	-	-	384,615,586	266,578,544	500,477
19 Deferred debits	2,718,432,070	1,518,664,287	-	74,811,132	-	-	-	-	-	-	99,352,521	-	758,922,961	266,419,078	262,090
20 Total assets	33,748,580,332	2,196,052,342	(6,985,986)	74,811,132	-		1,827,076,518	-	14,810,912,417	9,723,532,578	99,352,521	25,605,202	2,874,115,095	2,088,881,743	35,226,768
21 Debt, leases, and financial obligations	(10,539,010,633)	(67,006,063)	-	(10,472,004,570)	-	-	-	-	-	-	-	-	-	-	-
22 Notes payable	(868,264,173)	(775,225,864)	-	-	(93,038,309)	-	-	-	-	-	-	-	-	-	-
23 Accounts payable	(745,193,758)	-	-	-	-	-	-	-	-	-	-	-	(462,396,812)	(276,227,016)	(6,569,931)
24 Customer deposits	(35,630,529)	-	-	-	-	-	-	-	-	-	-	-	(22,507,188)	(13,123,340)	-
25 Accrued interest	(110,334,094)	(6,879,283)	-	-	-	-	-	-	-	-	-	-	(64,100,601)	(39,074,882)	(279,328)
26 Dividends payable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27 Accrued taxes	(616,603,927)	-	-	-	-	-	-	-	-	-	-	-	(363,911,840)	(252,213,914)	(478,173)
28 Other liabilities	(189,054,653)	(133,844,414)	-	-	-	-	-	-	-	-	(2,010,778)	-	(37,795,520)	(15,403,941)	-
29 Customer advances	(96,373,574)	-	-	-	-	-	-	-	(63,428,034)	(32,945,540)	-	-	-	-	-
30 Deferred income and investment taxes	(6,050,181,095)	5,465,306	-	-	-	(125,573,884)	(5,930,072,518)	-	-	-	-	-	-	-	-
31 Deferred credits	(3,697,236,649)	(932,286,699)	-	-	(29,145,016)		-	-	(1,231,269,222)	(1,320,000,122)	(60,187,287)	-	(107,860,411)	(13,837,878)	(2,650,014)
32 Total liabilities	(22,947,883,084)	(1,909,777,015)	-	(10,472,004,570)	(122,183,325)	(125,573,884)	(5,930,072,518)	-	(1,294,697,255)	(1,352,945,663)	(62,198,064)	-	(1,058,572,372)	(609,880,972)	(9,977,445)
33 Common equity	(10,763,382,449)	15,326,629	-	-	-	-	-	(10,778,709,078)	-	-	-	-	-	-	-
34 Preferred stock	(37,314,800)	-	-	-	-	-	-	(37,314,800)	-	-	-	-	-	-	-
35 Total equity	(10,800,697,249)	15,326,629	-	-	-	-	-	(10,816,023,878)	-	-	-	-	-	-	-
36 Net assets (liabilities)	$ -	$ 301,601,956	$ (6,985,986)	$ (10,397,193,438)	$ (122,183,325)	$ (125,573,884)	$ (4,102,996,000)	$ (10,816,023,878)	$ 13,516,215,162	$ 8,370,586,915	$ 37,154,457	$ 25,605,202	$ 1,815,542,724	$ 1,479,000,771	$ 25,249,323

Schedule: C-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Net Operating Income
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-3 (HLR-9)
Schedule: C-1
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Sales revenues	Exhibit No.: A-3 (HLR-11)	2,178,973
2	Transportation revenues	Exhibit No.: A-3 (HLR-11)	115,122
3	Other revenues	Exhibit No.: A-3 (HLR-11)	105,825
4	Total operating revenues	Sum of Lines 1 through 3	2,399,920
5	Cost of gas sold	Exhibit No.: A-3 (HLR-12)	875,604
6	LAUF	Exhibit No.: A-3 (HLR-13), Line 3	21,116
7	Company use gas	Exhibit No.: A-3 (HLR-13), Line 4	(820)
8	Operations and maintenance	Exhibit No.: A-3 (HLR-13), Line 23	423,918
9	Depreciation	Exhibit No.: A-3 (HLR-15), Line 9	337,042
10	Amortization	Exhibit No.: A-3 (HLR-15), Line 13	8,946
11	Property taxes	Exhibit No.: A-3 (HLR-16), Line 1	156,077
12	General taxes	Exhibit No.: A-3 (HLR-16) Line 6 + Line10	18,829
13	Other (local) taxes	Exhibit No.: A-3 (HLR-19)	778
14	State income taxes	Exhibit No.: A-3 (HLR-18)	17,273
15	Federal income taxes	Exhibit No.: A-3 (HLR-17)	73,864
16	Total operating expenses	Sum of Lines 5 through 15	1,932,627
17	Net operating income	Line 4 - Line 16	467,293
18	AFUDC	Exhibit No.: A-3 (HLR-20)	5,808
19	Net operating income, including AFUDC	Line 17 + Line 18	473,101
	Adjustments to Net Operating Income		
20	Sales revenue weather adjustment	Exhibit No.: A-13 (HLR-37), Col. (q), Line 2	79,820
21	Transportation revenue weather adjustment	Exhibit No.: A-13 (HLR-37), Col. (q), Line 3	3,627
22	EWR surcharge revenues	Exhibit No.: A-13 (HLR-37), Col. (q), Line 4	(67,512)
23	Jobwork revenues	Exhibit No.: A-13 (HLR-37), Col. (q), Line 5	227
24	Interest income on cash operating accounts	Exhibit No.: A-13 (HLR-37), Col. (q), Line 6	353
25	Other revenues adjustments	Exhibit No.: A-13 (HLR-37), Col. (q), Line 7	(4,839)
26	EWR surcharge expenses	Exhibit No.: A-13 (HLR-37), Col. (q), Line 8	67,512
27	Jobwork expenses	Exhibit No.: A-13 (HLR-37), Col. (q), Line 9	(45)
28	Compensation expenses	Exhibit No.: A-13 (HLR-37), Col. (q), Line 10	82
29	Advertising expenses	Exhibit No.: A-13 (HLR-37), Col. (q), Line 11	-
30	Dues, donations, & lobbying expenses	Exhibit No.: A-13 (HLR-37), Col. (q), Line 12	247
31	Interest expense on security deposits	Exhibit No.: A-13 (HLR-37), Col. (q), Line 13	(177)
32	Voluntary Separation Program (VSP) expenses	Exhibit No.: A-13 (HLR-37), Col. (q), Line 14	9,939
33	Income tax effect of interest	Exhibit No.: A-13 (HLR-37), Col. (q), Line 15	(850)
34	Interest synchronization adjustment	Exhibit No.: A-13 (HLR-37), Col. (q), Line 16	239
35	Total net operating income adjustments	Sum of Lines 20 through 34	88,623
36	Adjusted net operating income	Line 19 + Line 35	561,724

Schedule: C-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Revenue Conversion Factor
For the Historical Year Ended December 31, 2023

Case No.: U-21806
Exhibit No.: A-3 (HLR-10)
Schedule: C-2
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Income base - before taxes		100.0000
2	State income tax	Line 1 * 5.24% State Income Tax Rate	5.2400
3	Other (local) income tax	Line 1 * 0.16% Other (Local) Income Tax Rate	0.1600
4	Federal income tax base	Line 1 - Line 2 - Line 3	94.6000
5	Federal income tax	Line 4 * 21.00% Federal Income Tax Rate	19.8660
6	Income base - after taxes	Line 4 - Line 5	74.7340
7	Revenue conversion factor	Line 1 / Line 6	1.3381

Schedule: C-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Operating Revenue
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-3 (HLR-11)
Schedule: C-3
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Sales revenues	Ex. A-15 (MA-14), Col.(a), Line 5 + Line 9	2,178,973
2	Transportation revenues	Ex. A-15 (MA-14), Col.(a), Line 8	115,122
	Other Revenues		
3	Forfeited discounts	P-522, p.300, Line 15	6,322
4	Miscellaneous service revenues	P-522, p.300, Line 16	69,498
5	Revenue from transmission of gas of others, less transporation revenues {a}	P-522, p.300, Line 17 - Sum of P-522, p.313.1, Col. (f), Line 3 through P-522, p.313.1, Col. (f), Line 19	13,447
6	Rent from gas property	P-522, p.300, Line 21	290
7	Interdepartmental rents	P-522, p.300, Line 22	-
8	Other gas revenues	P-522, p.300, Line 23	16,267
9	Total other revenues	Sum of Lines 3 through 8	105,825
10	Total operating revenues	Line 1 + Line 2 + Line 9	2,399,920

Notes

{a} Transportation revenues related to MCV, the Jackson Plant, and others under ACT 9 contract have been omitted from the calculation of total revenue from the transmission of gas of others. These are Act 9 contracts and not tariff rates. These contracts remain in other revenue so that customers benefit from the revenue derived from the assets they pay for.

Schedule: C-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Gas Sold
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-3 (HLR-12)
Schedule: C-4
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Total purchased gas	P-522, p.321, Line 77	640,890
2	Gas withdrawn from storage	P-522, p.321, Line 86	558,794
3	Gas delivered to storage	P-522, p.321, Line 87	(303,363)
4	Total gas used in utility operations	P-522, p.321, Line 94	247
5	Synthetic gas supply expenses	P-522, p.321, Line 95a	16
6	Total production expenses	P-522, p.321, Line 97	896,584
7	Remove: Total gas used in utility operations	Line 4 * -1	(247)
8	Remove: Synthetic gas supply expenses	Line 5 * -1	(16)
9	Remove: LAUF	WP-HLR-7, line 14	(20,716)
10	Total cost of gas sold	Sum of Lines 6 through 9	875,604

Schedule: C-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Operation and Maintenance Expenses
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-3 (HLR-13)
Schedule: C-5
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
	Lost and Unaccounted for Gas		
1	LAUF	WP-HLR-7, line 14	20,716
2	Amortized gas storage losses	P-522, p.322, Line 110	400
3	LAUF, including storage losses	Line 1 + Line 2	21,116
	Company Use Gas		
4	Total gas used in utility operations	P-522, p.321, Line 94	247
5	Distribution expense adjustment	Exhibit No.: A-73 (TKJ-2), Line 2 Less P-522, p.321, Line 94	(1,066)
6	Gas used in utility operations per Company witness Exhibit No.: A-73 (TKJ-2), Line 2	Line 4 + Line 5	(820)
	Other O&M Expense		
7	Underground storage expenses, net of amortized gas storage losses	P-522, p.322, Line 125 Less P-522, p.322, Line 110	29,670
8	Total transmission expenses	P-522, p.324, Line 201	43,086
9	Total distribution expenses	P-522, p.324, Line 229	160,759
10	Total customer accounts expenses	P-522, p.324, Line 237	60,007
11	Total customer service and information expenses	P-522, p.325, Line 244	92,947
12	Total sales expenses	P-522, p.325, Line 251	69
13	Total administrative and general expenses	P-522, p.325, Line 270	43,453
14	Total operation and maintenance expenses	Sum of lines 7 through 13	429,992
15	Include: cloud computing amortization included in O&M	Exhibit No.: A-3 (HLR-14), Line 119	3
16	Include: EICP operational incentive goals	Exhibit No.: A-3 (HLR-14), Line 120	1,195
17	Include: non-energy related uncollectible expenses	Exhibit No.: A-3 (HLR-14), Line 121	3,954
18	Include: jobwork-related ASP customer installation expenses	Exhibit No.: A-3 (HLR-14), Line 122	33
19	Exclude: RNG program expenses	Exhibit No.: A-3 (HLR-14), Line 116	(404)
20	Exclude: one-time consulting expenses	Exhibit No.: A-3 (HLR-14), Line 117	(2,792)
21	Exclude: MGP amortization expense	Exhibit No.: A-47 (MJF-5), p.1, Col. (u)	(8,881)
22	Exclude: gas used in utility operations included in storage and transmission expense	Exhibit No.: A-73 (TKJ-2), Line 2	820
23	Total other O&M expenses	Sum of Lines 14 through 22	423,918

Schedule: C-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Operation and Maintenance Expenses by Witness
For the Historical Year Ended December 31, 2023
(In Dollars)

Case No.: U-21806
Exhibit No.: A-3 (HLR-14)
Schedule: C-5.1
Page: 1 of 2
Witness: HLRayl
Date: December 2024

Line No.	Account Number	Account Description	(c) IT & Security Baker	(d) Customer Experience Byrom	(e) Incentive Compensation Conrad	(f) Corporate Foster	(g) Transmission / Pipeline Griffin	(h) Employee Benefits Grob	(i) Facilities Guinn	(j) Compression / Storage Joyce	(k) Engineering Pascarello	(l) Operations Pnacek	(m) Other Rayl	(n) Total O&M Expense Per Witnesses	(o) MPSC P-522 O&M Expenses	(p) Variance
1	98030010	(803) Natural Gas Transmission Line Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 640,889,524	$ 640,889,524
2	98081010	(808.1) Gas Withdrawn from Storage - Debit	-	-	-	-	-	-	-	-	-	-	-	-	558,794,213	558,794,213
3	98082010	(808.2) Gas Delivered to Storage - Credit	-	-	-	-	-	-	-	-	-	-	-	-	(303,363,101)	(303,363,101)
4	98100010	(810) Gas Used for Compressor Station Fuel - Credit	-	-	-	-	-	-	-	-	-	-	-	-	2,219,768	2,219,768
5	98120010	(812) Gas Used for Other Utility Operations - Credit	-	-	-	-	-	-	-	-	-	-	-	-	(1,972,953)	(1,972,953)
6	98130010	(813) Other Gas Supply Expenses	-	-	-	-	-	-	-	-	-	-	-	-	16,096	16,096
7	98140010	(814) Operation Supervision and Engineering	-	-	-	-	-	-	-	-	100,283	244,929	-	345,212	345,211	(1)
8	98160010	(816) Wells Expenses	-	-	-	-	-	-	-	-	-	29,710	-	29,710	29,710	0
9	98170010	(817) Lines Expense	-	-	-	-	-	-	-	-	280,940	264,494	-	545,434	545,434	(0)
10	98180010	(818) Compressor Station Expenses	-	-	-	30,863	-	-	425,525	2,945,887	550,313	13,120	-	3,965,707	3,965,707	0
11	98190010	(819) Compressor Station Fuel and Power	-	-	-	-	-	-	-	1,281,394	-	-	-	1,281,394	5,104,185	3,822,791
12	98200010	(820) Measuring and Regulating Station Expenses	-	-	-	-	-	-	-	-	-	161,913	-	161,913	161,913	(0)
13	98210010	(821) Purification Expenses	-	-	-	-	-	-	-	157,736	-	-	-	157,736	157,736	(0)
14	98230010	(823) Gas Losses	-	-	-	-	-	-	-	-	-	-	-	-	399,593	399,593
15	98240010	(824) Other Expenses	2,320,686	-	-	-	-	-	161,175	-	-	1,394,301	-	3,876,162	4,408,837	532,675
16	98300010	(830) Maintenance Supervision and Engineering	-	-	-	852,820	-	-	25,091	-	100,464	202,900	-	1,181,275	1,181,275	(0)
17	98320010	(832) Maintenance of Reservoirs and Wells	-	-	-	-	-	-	-	-	630,399	428,578	-	1,058,978	1,058,978	0
18	98330010	(833) Maintenance of Lines	-	-	-	-	-	-	41,392	-	280,721	4,047,847	-	4,369,960	4,369,961	1
19	98340010	(834) Maintenance of Compressor Station Equipment	-	-	-	30,863	-	-	264,351	7,691,188	458,880	(104,429)	-	8,340,852	8,340,853	1
20	98350010	(835) Maintenance of Measuring and Regulating Station Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	98360010	(836) Maintenance of Purification Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	98500010	(850) Operation Supervision and Engineering	-	-	-	150,376	-	-	-	164,785	3,947,216	2,159,583	-	6,421,960	6,421,959	(1)
23	98510010	(851) System Control and Load Dispatching	886,078	-	-	-	-	-	-	-	4,024,080	-	-	4,910,159	4,910,159	0
24	98530010	(853) Communication System Expenses	-	-	-	35,696	-	-	248,819	1,175,307	10,473	2,315	-	1,472,609	1,472,609	0
25	98540010	(854) Gas for Compressor Station Fuel	-	-	-	-	-	-	-	-	-	-	-	-	(6,032,931)	(6,032,931)
26	98550010	(855) Other Fuel and Power for Compressor Stations	-	-	-	-	-	-	-	507,661	-	-	-	507,661	507,661	(0)
27	98560010	(856) Mains Expenses	-	-	-	-	15,752,787	-	-	-	180,297	2,076,052	-	18,009,136	18,009,197	61
28	98570010	(857) Measuring and Regulating Station Expenses	-	-	-	-	-	-	19,734	0	399,390	902,648	-	1,321,773	2,179,500	857,727
29	98590010	(859) Other Expenses	1,140,744	-	-	-	1,186,853	-	-	-	19,890	1,239,314	-	3,586,801	3,586,801	(0)
30	98600010	(860) Rents	-	-	-	-	-	-	-	-	17,800	-	-	17,800	17,800	-
31	98610010	(861) Maintenance Supervision and Engineering	-	-	-	-	-	-	-	-	204,002	384,020	-	588,022	588,022	(0)
32	98630010	(863) Maintenance of Mains	-	-	-	-	2,278,805	-	-	-	180,297	2,514,774	-	4,973,876	4,973,877	1
33	98640010	(864) Maintenance of Compressor Station Equipment	-	-	-	35,696	-	-	144,179	3,791,604	10,473	2,315	-	3,984,267	3,984,267	(0)
34	98650010	(865) Maintenance of Measuring and Reg. Station Equipment	-	-	-	-	3,832	-	2,244	-	-	2,461,040	-	2,467,116	2,467,116	(0)
35	98700010	(870) Operation Supervision and Engineering	-	4,870	-	204,195	-	-	-	-	2,405,329	4,116,385	-	6,730,779	6,730,780	1
36	98720010	(872) Compressor Station Labor and Expenses	-	-	-	1,328	-	-	24,066	-	-	29,225	-	54,619	54,700	81
37	98740010	(874) Mains and Services Expenses	-	-	-	2,271,794	-	-	49,946	-	145,256	28,154,760	-	30,621,755	30,619,766	(1,989)
38	98750010	(875) Measuring and Regulating Station Expenses - General	-	-	-	-	-	-	-	-	-	5,454,006	-	5,454,006	5,454,006	0
39	98780010	(878) Meter and House Regulator Expenses	-	-	-	-	-	-	-	-	-	8,961,176	-	8,961,176	8,961,176	(0)
40	98790010	(879) Customer Installations Expenses	-	-	-	-	-	-	-	-	-	3,780,898	51,679,682	55,460,580	55,427,444	(33,136)
41	98800010	(880) Other Expenses	9,617,376	-	-	3,335,485	-	-	803,934	-	1,097,736	7,319,431	-	22,173,962	22,175,950	1,988
42	98850010	(885) Maintenance Supervision and Engineering	-	-	-	-	-	-	-	164,419	440,172	1,075,885	-	1,680,476	1,680,475	(1)
43	98860010	(886) Maintenance of Structures and Improvements	-	-	-	-	-	-	62,854	-	-	-	-	62,854	62,855	1
44	98870010	(887) Maintenance of Mains	-	-	-	-	811,642	-	-	-	-	8,373,761	-	9,185,403	9,185,402	(1)
45	98880010	(888) Maintenance of Compressor Station Equipment	-	-	-	-	-	-	-	-	-	19,357	-	19,357	19,357	0
46	98890010	(889) Maintenance of Meas. And Reg. Sta. Equip. - General	-	-	-	-	-	-	-	-	-	2,824,909	-	2,824,909	2,824,909	(0)
47	98920010	(892) Maintenance of Services	-	-	-	-	-	-	-	-	527	11,727,884	-	11,728,411	11,728,409	(2)
48	98930010	(893) Maintenance of Meters and House Regulators	-	-	-	-	-	-	-	-	-	5,578,749	-	5,578,749	5,578,749	(0)
49	98940010	(894) Maintenance of Other Equipment	-	-	-	156,133	-	-	17,121	-	-	82,109	-	255,363	255,363	(0)
50	99010020	(901) Supervision	-	5,675,785	-	406,330	-	-	277,752	-	67,074	453,226	-	6,880,167	6,880,169	2
51	99020020	(902) Meter Reading Expenses	-	-	-	-	-	-	-	-	-	3,024,400	-	3,024,400	3,024,400	(0)
52	99030020	(903) Customer Records and Collection Expenses	5,410,074	28,174,355	-	415,644	-	-	36,713	-	-	2,015,842	-	36,052,628	36,052,630	2
53	99041020	(904) Uncollectible Accounts	-	-	-	17,234,331	-	-	-	-	-	(416,804)	1,185,980	18,003,507	14,049,800	(3,953,707)
54	99050020	(905) Miscellaneous Customer Accounts Expense	-	429	-	-	-	-	-	-	-	-	-	429	429	0
55	99070020	(907) Supervision	-	308,830	-	-	-	-	-	-	-	-	-	308,830	308,830	0
56	99080020	(908) Customer Assistance Expenses	-	858,460	-	-	-	-	-	-	-	-	853,289	1,711,749	92,452,216	90,740,467
57	99090020	(909) Informational and Instructional Expenses	-	-	-	2	-	-	-	-	13,357	172,723	-	186,082	186,082	0
58	99160020	(916) Miscellaneous Sales Expenses	-	69,445	-	-	-	-	-	-	-	-	-	69,445	69,445	(0)
59	99200020	(920) Administrative and General Salaries	3,873,154	121,516	1,947,525	17,531,693	-	831,794	1,595,874	-	427,843	-	-	26,329,399	26,337,167	7,768
60	99210020	(921) Office Supplies and Expenses	888,245	121,175	-	(65,001)	-	14,930	2,490,039	-	20,762	-	-	3,470,152	3,395,700	(74,452)
61	99220020	(922) Administrative Expenses Transferred - Credit	-	-	(1,168,073)	(15,098,932)	-	-	-	-	-	-	-	(16,267,005)	(16,267,005)	(0)
62	99230020	(923) Outside Services Employed	9,018,784	289,407	-	3,725,447	-	732,784	507,851	-	568	125,000	-	14,399,841	17,191,568	2,791,727
63	99240020	(924) Property Insurance	-	-	-	1,729,523	-	-	-	-	-	-	-	1,729,523	1,729,523	(0)
64	99250020	(925) Injuries and Damages	-	-	-	12,321,765	-	-	-	-	-	-	-	12,321,765	21,203,255	8,881,490
65	99260020	(926) Employee Pensions and Benefits	-	-	-	(909,966)	-	(28,180,465)	-	-	-	-	-	(29,090,431)	(29,077,436)	12,995
66	99280020	(928) Regulatory Commission Expenses	-	-	-	340,632	-	-	-	-	-	-	-	340,632	340,632	0
67	99301020	(930.1) General Advertising Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	99302020	(930.2) Miscellaneous General Expenses	-	1,064,227	-	2,173,801	-	-	-	-	-	-	-	3,238,028	16,240,228	13,002,200
69	99310020	(931) Rents	-	-	-	(31,424)	-	-	34,172	-	-	-	-	2,748	77,204	74,456
70	99350020	(935) Maintenance of General Plant	-	106	-	(123,952)	-	-	2,405,766	-	-	-	-	2,281,920	2,281,920	(0)

Schedule: C-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Operation and Maintenance Expenses by Witness
For the Historical Year Ended December 31, 2023

Case No.: U-21806
Exhibit No.: A-3 (HLR-14)
Schedule: C-5.1
Page: 2 of 2
Witness: HLRayl
Date: December 2024

Line No.	Account Number	Account Description	IT & Security Baker	Customer Experience Byrom	Incentive Compensation Conrad	Corporate Foster	Transmission / Pipeline Griffin	Employee Benefits Grob	Facilities Guinn	Compression / Storage Joyce	Engineering Pascarello	Operations Pnacek	Other Rayl	Total O&M Expense Per Witnesses	MPSC P-522 O&M Expenses	Variance
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
71	94040020	(404) Amortization of Utility Plant	2,683	-	-	-	-	-	-	-	-	-	-	2,683	-	(2,683)
72	94160000	(416) Merchandising, Jobbing, and Contract Work	-	-	-	-	-	-	-	-	-	-	4,301	4,301	-	(4,301)
73	94170020	(417.1) Nonutility Operations	-	-	-	-	-	-	-	-	-	-	56,442	56,442	-	(56,442)
74	94265010	(426) Other Deductions	-	-	1,194,548	-	-	-	-	-	-	-	-	1,194,548	-	(1,194,548)
75	94310000	(431) Other Interest Expense	-	-	-	-	-	-	-	-	-	-	237,141	237,141	-	(237,141)
76	---	Allocation and rounding adjustments	92,233	-	-	-	-	-	-	-	-	739	-	92,972	-	(92,972)
77	Total O&M expense		$ 33,250,059	$ 36,688,605	$ 1,974,000	$ 46,755,142	$ 20,033,919	$ (26,600,957)	$ 9,638,598	$ 17,879,982	$ 16,014,542	$ 111,299,086	$ 54,016,835	$ 320,949,808	$ 1,326,975,075	$ 1,006,025,267

Reconciliation of MPSC P-522 to Witness-Sponsored O&M Expense

78	Total MPSC P-522 O&M Expense, p. 325, Line 271				$ 1,326,975,075
Variances:					
79	94040020	(404) Amortization of Utility Plant	Include: cloud computing amortization classified as O&M expense for the rate case	Col. (c), Line 71	2,683
80	94160000	(416) Merchandising, Jobbing, and Contract Work	Incude: Utility jobwork expenses	WP-HLR-10	4,301
81	94170020	(417.1) Nonutility Operations	Include: Nonutility jobwork expenses	WP-HLR-10	56,442
82	94265010	(426) Other Deductions	Include: EICP operational incentive goals	Col. (e), Line 74	1,194,548
83	94310000	(431) Other Interest Expense	Include: Interest expense on security deposits	WP-HLR-15	237,141
84	98030010	(803) Natural Gas Transmission Line Purchases	Exclude: included in calculation of cost of gas sold	Included in Exhibit No.: A-3 (HLR-12)	(640,889,524)
85	98081010	(808.1) Gas Withdrawn from Storage - Debit	Exclude: included in calculation of cost of gas sold	Included in Exhibit No.: A-3 (HLR-12)	(558,794,213)
86	98082010	(808.2) Gas Delivered to Storage - Credit	Exclude: included in calculation of cost of gas sold	Included in Exhibit No.: A-3 (HLR-12)	303,363,101
87	98100010	(810) Gas Used for Compressor Station Fuel - Credit	Exclude: included in calculation of cost of gas sold	Included in Exhibit No.: A-3 (HLR-12)	(2,219,768)
88	98120010	(812) Gas Used for Other Utility Operations - Credit	Exclude: included in calculation of cost of gas sold	Included in Exhibit No.: A-3 (HLR-12)	1,972,953
89	98130010	(813) Other Gas Supply Expenses	Exclude: included in calculation of cost of gas sold	Included in Exhibit No.: A-3 (HLR-12)	(16,096)
90	98190010	(819) Compressor Station Fuel and Power	Exclude: included in calculation of company use gas	Included in Exhibit No.: A-3 (HLR-13), Line 6	(3,822,791)
91	98230010	(823) Gas Losses - amortization of storage losses	Exclude: included in calculation of LAUF gas	Exhibit No.: A-3 (HLR-13), Line 2	(399,593)
92	98240010	(824) Other Expenses	Exclude: included in calculation of company use gas	Included in Exhibit No.: A-3 (HLR-13), Line 6	(532,675)
93	98540010	(854) Gas for Compressor Station Fuel	Exclude: included in calculation of company use gas	Included in Exhibit No.: A-3 (HLR-13), Line 6	6,032,931
94	98560010	(856) Mains Expenses	Exclude: included in calculation of company use gas	Included in Exhibit No.: A-3 (HLR-13), Line 6	(61)
95	98570010	(857) Measuring and Regulating Station Expenses	Exclude: included in calculation of company use gas	Included in Exhibit No.: A-3 (HLR-13), Line 6	(857,727)
96	98720010	(872) Compressor Station Labor and Expenses	Exclude: RNG program expenses	Col. (p), Line 36	(81)
97	98790010	(879) Customer Installations Expenses	Include: Jobwork-related ASP customer installation expenses	WP-HLR-10	33,136
98	99041020	(904) Uncollectible Accounts	Include: non-energy related uncollectibles expenses	Col. (p), Line 53	3,953,707
99	99080020	(908) Customer Assistance Expenses	Exclude: EWR expenses	WP-HLR-9	(90,336,102)
100	99080020	(908) Customer Assistance Expenses	Exclude: RNG program expenses	Included in Col. (p), Line 56	(404,365)
101	99200020	(920) Administrative and General Salaries	Exclude: corporate giving salaries expense disallowance	WP-HLR-12	(7,767)
102	99230020	(923) Outside Services Employed	Exclude: one-time consulting expenses	Col. (p), Line 62	(2,791,727)
103	99250020	(925) Injuries and Damages	Exclude: MGP amortization included in amortization expense for the rate case	Col. (p), Line 64	(8,881,490)
104	99260020	(926) Employee Pensions and Benefits	Exclude: corporate salaries (executive physicals) expense disallowance	WP-HLR-12	(12,996)
105	99302020	(930.2) Miscellaneous General Expenses	Exclude: strategic communication salaries expense disallowance	WP-HLR-12	(89,180)
106	99302020	(930.2) Miscellaneous General Expenses	Exclude: corporate dues, donations & lobbying expense disallowance	WP-HLR-14	(331,137)
107	99302020	(930.2) Miscellaneous General Expenses	Exclude: VSP expenses	WP-HLR-16	(12,581,883)
108	---	Allocation and rounding adjustments	Col. (p), Line 76		(92,972)
109	Total O&M expense per witnesses		Sum of Lines 78 through 108		320,763,870
110	Total O&M expense per Exhibit No.: A-13 (HLR-37)		Exhibit No.: A-13 (HLR-37), Col. (i), Line 17		320,856,837
111	Difference		Line 109 - Line 110		(92,967)

Reconciliation of MPSC P-522 to Exhibit No.: A-3 (HLR-13) and Exhibit No.: A-13 (HLR-37)

112	Total MPSC P-522 O&M Expense, p. 325, Line 271	Col. (o), Line 77	$ 1,326,975,075
113	Exclude: cost of gas sold	Col. (o), Sum of Lines 84 through 89	(896,583,547)
114	Exclude: company use gas included in distribution expenses	Col. (o), Sum of Lines 90 and 92 through 95	819,678
115	Exclude: amortization of storage losses included in LAUF	Col. (o), Line 91	(399,593)
116	Exclude: RNG program expenses	Col. (o), Line 96 + Line 100	(404,446)
117	Exclude: one-time consulting expenses	Col. (o), Line 102	(2,791,727)
118	Exclude: amortization of MGP	Col. (o), Line 103	(8,881,490)
119	Include: Cloud computing amortization	Col. (o), Line 79	2,683
120	Include: EICP operational incentive goals	Col. (o), Line 82	1,194,548
121	Include: non-energy related uncollectibles expenses	Col. (o), Line 98	3,953,707
122	Include: Jobwork-related ASP customer installation expenses	Col. (o), Line 97	33,136
123	Total adjusted MPSC P-522 O&M expense	Sum of Lines 112 through 122	423,918,024
124	Total O&M expense per Exhibit No.: A-3 (HLR-13)	Exhibit No.: A-3 (HLR-13), Line 23	423,918,024
125	Difference	Line 123 - Line 124	(0)
126	Total O&M expense per Exhibit No.: A-3 (HLR-13)	Exhibit No.: A-3 (HLR-13), Line 23	$ 423,918,024
127	O&M adjustments/disallowances	Exhibit No.: A-13 (HLR-37), Col. (i), Sum of Lines 8 through 14	(103,061,182)
128	Total adjusted other O&M expense	Line 126 + Line 127; also see Col. (o), Line 109	320,856,843
129	Total adjusted other O&M expense per Exhibit No.: A-13 (HLR-37)	Exhibit No.: A-13 (HLR-37), Col. (i), Line 17	320,856,837
130	Difference	Line 128 - Line 129	5

Schedule: C-6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Depreciation and Amortization Expenses
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-3 (HLR-15)
Schedule: C-6
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
	Depreciation Expenses		
1	Intangible plant	P-522, p.337, Col.(g), Line 1	3,967
2	Underground gas storage plant	P-522, p.337, Col.(g), Line 5	29,944
3	Transmission plant	P-522, p.337, Col.(g), Line 8	60,693
4	Distribution plant	P-522, p.337, Col.(g), Line 9	205,360
5	General plant	P-522, p.337, Col.(g), Line 10	6,654
6	Allocated gas portion of common general plant	P-522, p.337, Col.(g), Line 13	30,361
7	Allocated gas portion of common limited term plant	P-522, p.337, Col.(g), Line 14	66
8	Exclude: cloud computing amortization included in O&M	Exhibit No.: A-3 (HLR-14), Col. (c), Line 71	(3)
9	Total depreciation expenses	Sum of Lines 1 through 8	337,042
	Amortization Expenses		
10	Amortization of utility plant acquisition adjustment	P-521, p.115, Col. (g), Line 9	64
11	Regulatory debits	P-521, p.115, Col. (g), Line 12	-
12	Include: Amortization of MGP	Exhibit No.: A-47 (MJF-5), p.1, Col. (u)	8,881
13	Total adjusted amortization expenses	Sum of Lines 10 through 12	8,946

Schedule: C-7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
General Taxes
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-3 (HLR-16)
Schedule: C-7
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Local real and personal property tax	P-521, p.262.1, Col.(j), Line 50	156,077
2	Federal unemployment tax	P-521, p.262.1, Col.(j), Line 4	71
3	Federal FICA tax	P-521, p.262.1, Col.(j), Line 6	13,131
4	Federal excise tax	P-521, p.262.1, Col.(j), Line 8	(19)
5	State unemployment tax	P-521, p.262.1, Col.(j), Lines 15 - 33	357
6	Total payroll taxes	Sum of Lines 2 through 5	13,540
7	State fuel tax	P-521, p.262.1, Col.(j), Lines 34 - 35	-
8	State MPSC assessment	P-521, p.262.1, Col.(j), Lines 36 - 37	4,694
9	State sales and use tax absorbed by company	P-521, p.262.1, Col.(j), Lines 40 - 47	594
10	Other general taxes	Sum of Lines 7 through 9	5,288
11	Total general taxes	Line 1 + Line 6 + Line 10	174,905

Schedule: C-8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Federal Income Taxes
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-3 (HLR-17)
Schedule: C-8
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Federal income taxes	P-521, p.115, Col. (g), Line 15	89
2	Provision for deferred income taxes	P-521, p.115, Col. (g), Line 17	260,507
3	Provision for deferred income taxes - credit	P-521, p.115, Col. (g), Line 18	(165,598)
4	Investment tax credit adjustment, net	P-521, p.115, Col. (g), Line 19	(446)
5	Deferred state income tax expenses - historical year	Tax Department	(19,874)
6	Deferred other (local) income tax expenses - historical year	Tax Department	(814)
7	Total federal income taxes	Sum of Lines 1 through 6	73,864

Schedule: C-9

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
State Income Taxes
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-3 (HLR-18)
Schedule: C-9
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	State income taxes	P-521, p.262.1, Col.(j), Lines 11 - 14	(2,601)
2	Deferred state income taxes	Tax Department	19,874
3	Total state income taxes	Line 1 + Line 2	17,273

Schedule: C-10

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Other (or Local) Taxes
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-3 (HLR-19)
Schedule: C-10
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Other (local) income taxes	P-521, p.262.1, Col.(j), Line 51	(36)
2	Deferred other (local) income taxes	Tax Department	814
3	Total other (local) income taxes	Line 1 + Line 2	778

Schedule: C-11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Allowance for Funds Used During Construction
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-3 (HLR-20)
Schedule: C-11
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Total allowance for funds used during construction	WP-HLR-8	5,808

Schedule: C-12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Income Tax Effect of Interest
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-3 (HLR-21)
Schedule: C-12
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Rate base	Exhibit No.: A-2 (HLR-3)	9,479,241
2	Weighted cost of debt {a}	Exhibit No.: A-4 (HLR-23)	1.68%
3	Allowable interest expense	Line 1 * Line 2	158,965
4	Actual interest expense {b}	Line {b.7}	162,329
5	Increase/ (decrease) in allowable interest deduction	Line 3 - Line 4	(3,364)
6	Impact on taxable income	Line 5 * -1	3,364
7	Impact on local income taxes	Line 6 * 0.16% Other (Local) Income Tax Rate	5
8	Impact on state income taxes	Line 6 * 5.24% State Income Tax Rate	176
9	Impact on federal taxable income	Line 6 - Line 7 - Line 8	3,183
10	Impact on federal income taxes	Line 9 * 21.00% Federal Income Tax Rate	668
11	Total impact on net operating income	(Line 7 + Line 8 + Line 10) *-1	(850)

Notes

{a} Excludes JDITC

{b} Calculation of actual interest expense

{b.1}	Total fixed charges - financial basis	WP-HLR-8	161,686
{b.2}	Lease interest expense	SAP Account 99302020, Operational Account 8232004	242
{b.3}	Subtotal	Line {b.1} - Line {b.2}	161,445
{b.4}	AFUDC debt	WP-HLR-8	1,520
{b.5}	Subtotal	Line {b.3} + Line {b.4}	162,964
{b.6}	Preferred stock dividends	WP-HLR-8	635
{b.7}	Acutal ratemaking interest expense	Line {b.5} - Line {b.6}	162,329

Schedule: C-13

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Interest Synchronization Adjustment
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-3 (HLR-22)
Schedule: C-13
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Rate base	Exhibit No.: A-2 (HLR-3)	9,479,241
2	JDITC debt-related portion of the capital structure	Exhibit No.: A-4 (HLR-23)	0.25%
3	Portion of rate base funded by JDITC	Line 1 * Line 2	23,657
4	Cost of JDITC - debt portion	Exhibit No.: A-4 (HLR-23)	4.00%
5	Allowable JDITC interest expense	Line 3 * Line 4	945
6	Impact on taxable income	Line 5 * -1	(945)
7	Impact on local income taxes	Line 6 * 0.16% Other (Local) Income Tax Rate	(2)
8	Impact on state income taxes	Line 6 * 5.24% State Income Tax Rate	(50)
9	Impact on federal taxable income	Line 6 - Line 7 - Line 8	(894)
10	Impact on federal income taxes	Line 9 * 21.00% Federal Income Tax Rate	(188)
11	Total impact on net operating income	(Line 7 + Line 8 + Line 10) *-1	239

Schedule: D-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Structure and Rate of Return Summary
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-4 (HLR-23)
Schedule: D-1
Page: 1 of 1
Witness: HLRayl
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Capital Structure				Weighted Cost			
Line No	Description	Source	Amount	Percent Permanent Capital	Percent of Total Capital	Cost Rate %	Permanent Capital	Total Cost %	Conversion Factor	Pre-Tax Return
1	Long term debt	Exhibit No.: A-2 (HLR-7), Col. (d.1), Line 36	10,135,421	49.10%	40.40%	4.00% {1}	1.96%	1.61%		1.61%
2	Preferred stock	Exhibit No.: A-2 (HLR-7), Col. (d.5), Line 34	37,315	0.18%	0.15%	4.50% {2}	0.01%	0.01%	1.3381	0.01%
3	Common equity	Exhibit No.: A-2 (HLR-7), Col. (d.5), Line 33	10,470,148	50.72%	41.74%	9.90% {3}	5.02%	4.13%	1.3381	5.53%
4	Permanent capital	Sum of Lines 1 through 3	20,642,885							
5	Utility term loan	Exhibit No.: A-2 (HLR-7), Col. (d.2), Line 21	115,385		0.46%	5.41% {4}		0.02%		0.02%
6	Notes payable	Exhibit No.: A-2 (HLR-7), Col. (d.2), Line 22	134,731		0.54%	5.41% {4}		0.03%		0.03%
7	Advanced renewable reg liability	Exhibit No.: A-2 (HLR-7), Col. (d.2), Line 31	40,028		0.16%	5.41% {4}		0.01%		0.01%
8	Short term debt	Sum of Lines 5 through 7	290,144							
9	Deferred income taxes	Exhibit No.: A-2 (HLR-7), Col. (d.4), Line 36	4,024,193		16.04%	0.00%		0.00%		0.00%
10	Deferred JDITC - long term debt	See Note {5}	62,604		0.25%	4.00%		0.01%		0.01%
11	Deferred JDITC - preferred stock	See Note {5}	230		0.00%	4.50%		0.00%	1.3381	0.00%
12	Deferred JDITC - common equity	See Note {5}	64,672		0.26%	9.90%		0.03%	1.3381	0.03%
13	Total deferred JDITC	Exhibit No.: A-2 (HLR-7), Col. (d.3), Line 36	127,506							
14	Total	Sum of Lines 4, 8, 9, and 13	25,084,728					5.85%		7.26%

Notes

{1} Exhibit No.: A-4 (HLR-24)
{2} Exhibit No.: A-4 (HLR-26)
{3} Exhibit No.: A-4 (HLR-27)
{4} Exhibit No.: A-4 (HLR-25)
{5} The total deferred JDITC balance on line 13 is allocated to lines 10 through 12 based on the percent of permanent capital in column (d)

Schedule: D-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Long-Term Debt (Excluding Securitization)
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-4 (HLR-24)
Schedule: D-2
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	Description	Original Issue Date	Stated Maturity Date	Interest Rate %	Amount of Offering	Price to Public %	Underwriting & Financing Expense %	Net Proceeds to the Company %	Cost Based on Net Proceeds %	13-Mo Avg Amount Outstanding	Annual Cost
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Mortgage Bonds											
1	3.375%	Aug-09-2013	Aug-15-2023	3.375%	325,000	99.95%	0.765%	99.18%	3.472%	200,000	7,001
2	0.350%	Dec-14-2020	Jun-01-2023	0.350%	300,000	99.97%	0.485%	99.48%	0.562%	138,462	740
3	3.125%	Aug-18-2014	Aug-31-2024	3.125%	250,000	99.90%	0.790%	99.11%	3.230%	250,000	8,035
4	3.190%	Dec-17-2012	Dec-16-2024	3.190%	51,500	100.00%	0.536%	99.46%	3.244%	51,500	1,666
5	5.240%	May-30-2023	May-15-2026	5.240%	115,000	100.00%	0.116%	99.88%	5.282%	70,769	3,560
6	3.68% (Private Placement)	Oct-01-2018	Oct-01-2027	3.680%	100,000	100.00%	0.159%	99.84%	3.701%	100,000	3,698
7	3.390%	Dec-17-2012	Dec-15-2027	3.390%	35,500	100.00%	0.540%	99.46%	3.436%	35,500	1,216
8	3.800%	Nov-13-2018	Nov-15-2028	3.800%	300,000	99.75%	0.752%	99.00%	3.922%	300,000	11,698
9	4.650%	Jan-10-2023	Mar-01-2028	4.650%	425,000	99.81%	0.833%	98.98%	4.875%	392,308	20,085
10	5.070%	May-30-2023	May-15-2029	5.070%	50,000	100.00%	0.232%	99.77%	5.115%	30,769	1,498
11	4.900%	Aug-04-2023	Feb-15-2029	4.900%	500,000	99.95%	0.806%	99.14%	5.079%	192,308	10,299
12	4.600%	Jan-09-2024	May-30-2029	4.600%	600,000	99.77%	0.704%	99.06%	4.798%	-	-
13	3.600%	Aug-11-2022	Aug-15-2032	3.600%	350,000	99.93%	0.850%	99.08%	3.711%	350,000	12,898
14	3.18% (Private Placement)	Sep-28-2017	Sep-28-2032	3.180%	40,000	100.00%	0.333%	99.67%	3.208%	40,000	1,281
15	3.18% (Private Placement)	Nov-15-2017	Nov-15-2032	3.180%	60,000	100.00%	0.332%	99.67%	3.208%	60,000	1,921
16	5.170%	May-30-2023	May-15-2032	5.170%	95,000	100.00%	0.340%	99.66%	5.218%	58,462	2,902
17	4.625%	Feb-23-2023	May-15-2033	4.625%	700,000	99.45%	0.847%	98.60%	4.799%	592,308	28,551
18	5.800%	Aug-11-2005	Sep-15-2035	5.800%	175,000	99.81%	1.046%	98.76%	5.888%	175,000	10,222
19	3.52% (Private Placement)	Sep-28-2017	Sep-28-2037	3.520%	125,000	100.00%	0.444%	99.56%	3.551%	125,000	4,428
20	3.52% (Private Placement)	Nov-15-2017	Nov-15-2037	3.520%	210,000	100.00%	0.443%	99.56%	3.551%	210,000	7,438
21	5.380%	May-30-2023	May-15-2037	5.380%	140,000	100.00%	0.524%	99.48%	5.434%	86,154	4,448
22	4.01% (Private Placement)	Oct-01-2018	Oct-01-2038	4.010%	215,000	100.00%	0.349%	99.65%	4.036%	215,000	8,659
23	6.170%	Sep-01-2010	Sep-01-2040	6.170%	50,000	100.00%	0.984%	99.02%	6.243%	50,000	3,101
24	4.970%	Oct-15-2010	Oct-15-2040	4.970%	50,000	100.00%	0.539%	99.46%	5.005%	50,000	2,494
25	4.310%	Dec-17-2012	Dec-15-2042	4.310%	263,000	100.00%	0.528%	99.47%	4.342%	263,000	11,381
26	3.950%	May-17-2013	May-15-2043	3.950%	425,000	99.84%	1.034%	98.81%	4.019%	425,000	16,956
27	4.100%	Nov-06-2015	Nov-15-2045	4.100%	250,000	99.91%	1.054%	98.86%	4.167%	250,000	10,345
28	3.250%	Aug-10-2016	Aug-15-2046	3.250%	450,000	99.22%	1.058%	98.16%	3.347%	450,000	14,900
29	3.950%	Feb-22-2017	Jul-15-2047	3.950%	350,000	99.58%	1.066%	98.52%	4.035%	350,000	13,995
30	4.050%	May-14-2018	May-15-2048	4.050%	550,000	98.97%	1.076%	97.89%	4.174%	550,000	22,586
31	4.350%	Nov-13-2018	Apr-15-2049	4.350%	550,000	99.62%	1.054%	98.56%	4.436%	550,000	24,184
32	3.750%	May-28-2019	Feb-15-2050	3.750%	300,000	98.83%	1.086%	97.75%	3.876%	300,000	11,178
33	3.100%	Sep-03-2019	Aug-15-2050	3.100%	550,000	99.29%	0.971%	98.32%	3.186%	550,000	17,083
34	3.500%	Mar-26-2020	Aug-01-2051	3.500%	575,000	100.00%	1.094%	98.91%	3.558%	575,000	20,223
35	2.650%	Aug-02-2021	Aug-15-2052	2.650%	300,000	99.92%	1.065%	98.85%	2.705%	300,000	8,062
36	4.200%	Aug-11-2022	Sep-01-2052	4.200%	450,000	99.93%	1.075%	98.85%	4.268%	450,000	19,081
37	3.86% (Private Placement)	Sep-28-2017	Sep-28-2052	3.860%	20,000	100.00%	0.777%	99.22%	3.901%	20,000	776
38	3.86% (Private Placement)	Nov-15-2017	Nov-15-2052	3.860%	30,000	100.00%	0.775%	99.22%	3.901%	30,000	1,165
39	4.28% (Private Placement)	Oct-01-2018	Oct-01-2057	4.280%	185,000	100.00%	0.676%	99.32%	4.316%	185,000	7,950
40	2.500%	May-13-2020	May-01-2060	2.500%	525,000	100.00%	1.047%	98.95%	2.542%	525,000	13,374
41	4.350%	Aug-18-2014	Aug-31-2064	4.350%	250,000	99.14%	0.999%	98.14%	4.443%	250,000	10,968
42	Floating Rate FMB {a}	Sep-19-2019	Sep-15-2069	2.993%	75,649	100.00%	1.993%	98.01%	3.071%	75,649	3,884
43	Floating Rate FMB {b}	May-20-2020	May-20-2070	2.684%	134,349	100.00%	1.291%	98.71%	2.731%	134,349	6,792
44	Floating Rate FMB {c}	Oct-07-2020	Oct-07-2070	2.048%	126,497	100.00%	1.250%	98.75%	2.089%	126,497	6,419
45	Total Mortgage Bonds									10,133,033	399,142
Other Long-Term Debt											
46	PCRB - MSF LORB - 2019	Oct-01-2019	Oct-01-2049	1.800%	75,000	100.00%	1.485%	98.52%	1.865%	75,000	1,387
47	PCRB - MSF LORB - 2021	Oct-07-2021	Apr-01-2035	0.875%	35,000	100.00%	1.500%	98.50%	0.994%	35,000	342
48	Total Other Long-Term Debt									110,000	1,729
Cost of Long-Term Debt Calculation											
49	Total Annual Cost										400,870
50	Amortization of Losses on Reacquired Debt with Refunding (including Call Premiums)										4,110
51	Total Long-Term Debt Annual Cost Balance										404,980
52	Total Long-Term Debt										10,243,033
53	Unamortized Debt Discount and Premium Expense										(30,475)
54	Unamortized Debt Issuance Costs										(77,137)
55	Total Long-Term Debt Balance per Exhibit No.: A-2 (HLR-7), Col. (d.1), Line 36										10,135,421
56	Average Cost of Long-Term Debt										4.00%

Notes

{a} Interest rate for $76M floating rate FMBs due 2069 is 3-mo SOFR minus 3.839 basis points, resetting quarterly on 3/15, 6/15, 9/15, and 12/15
{b} Interest rate for $134M floating rate FMBs due 2070 is 3-mo SOFR minus 3.839 basis points, resetting quarterly on 2/20, 5/20, 8/20, and 11/20
{c} Interest rate for $126M floating rate FMBs due 2070 is 3-mo SOFR minus 3.839 basis points, resetting quarterly on 1/7, 4/7, 7/7, and 10/7

Schedule: D-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Short-Term Debt
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-4 (HLR-25)
Schedule: D-3
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount	(d) Annual Cost {1}	(e) Average Cost of Short-Term Debt [Col. (d) / Col. (c)]
1	Utility term loan	Exhibit No.: A-2 (HLR-7), Col. (d.2), Line 21	115,385		
2	Notes payable	Exhibit No.: A-2 (HLR-7), Col. (d.2), Line 22	134,731		
3	Advanced renewable reg liability	Exhibit No.: A-2 (HLR-7), Col. (d.2), Line 31	40,028		
4	Total	Sum of Lines 1 through 3	290,144	15,685	5.41%

Notes

{1} SAP Accounts 8000000, 8020000, 8030000, 8200000, 8220000, 8265001, and 8300000

Schedule: D-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Preferred Stock
For the Historical Year Ended December 31, 2023
($000)

Case No.: U-21806
Exhibit No.: A-4 (HLR-26)
Schedule: D-4
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Annual Dividend	(c) Par Value	(d) Discount / (Premium)	(e) Finance Expense	(f) Net Proceeds Received	(g) Number of Shares Outstanding	(h) Total Value of Outstanding Proceeds {1}	(i) Cost Rate %	(j) Annual Dollar Amount
1	Preferred stock	4.50	100	-	-	100	373,148	37,315	4.50%	1,679

Notes

{1} Exhibit No.: A-2 (HLR-7), Col. (d.5), Line 34

Schedule D-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Common Shareholders' Equity
For the Historical Year Ended December 31, 2023

Case No.: U-21806
Exhibit No.: A-4 (HLR-27)
Schedule: D-5
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description
1	The Company's authorized cost of common equity is 9.90%. This rate was approved by the Michigan Public Service Commission on August 30, 2023 in Gas Rate Case U-21308.

Schedule E-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Annual Service Area Deliveries by Major Customer Classes and System Output
5-Year Historical
(Consumption in MMcf)

Case No.: U-21806
Exhibit No.: A-5 (MA-1)
Schedule: E-1
Page: 1 of 1
Witness: MAhmed
Date: December 2024

Line No.	(a) Year	(b) Residential	(c) Commercial	(d) Industrial	(e) Inter-Departmental	(f) Total	(g) LAUF Gas Volumes MMcf	(h) % of Output	(i) Sendout
1	2019	167,703	85,837	59,435	238	313,214	5,917	1.9	319,131
2	2020	153,675	75,525	53,805	304	283,310	5,206	1.8	288,516
3	2021	147,363	76,844	57,056	400	281,662	-	-	281,662
4	2022	164,154	84,938	64,871	666	314,629	3,798	1.2	318,427
5	2023	142,260	77,230	62,667	161	282,317	5,055	1.8	287,372

Schedule E-1a

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of 2023 Historical Year Revenues
($000)

Case No.: U-21806
Exhibit No.: A-5 (MA-2)
Schedule: E-1a
Page: 1 of 1
Witness: MAhmed
Date: December 2024

Line	(a) Description	(b) Operating Revenues	(c) Source
	Gas Sales		
	Residential Service		
1	Single Family Dwelling A	$ 1,560,998	WP-MA-5
2	Multifamily Dwelling A-1	52,460	WP-MA-5
3	Total Residential Service	1,613,458	
	General Service		
4	Small Service GS-1	377,696	WP-MA-5
5	Medium Service GS-2	130,377	WP-MA-5
6	Large Service GS-3	57,438	WP-MA-5
7	Outdoor Lighting GL	4	WP-MA-5
8	Total General Service	565,515	
9	Total Gas Sales	2,178,973	
	Transportation		
10	Small Transport ST	43,378	WP-MA-6
11	Large Transport LT	29,351	WP-MA-6
12	Extra-large Transport XLT	30,891	WP-MA-6
13	Extra-Extra-large Transport XXLT	11,502	WP-MA-6
14	Total Transportation	115,122	
15	Total Tariff Revenues	2,294,095	
16	Miscellaneous Revenues	105,825	WP-MA-6
17	Total Revenues	$ 2,399,920	P522 page 305B Line 16

Schedule E-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2023 Historical Year Consumption and Customer Counts
(Consumption in MMcf)

Case No.: U-21806
Exhibit No.: A-5 (MA-3)
Schedule: E-2
Page: 1 of 1
Witness: MAhmed
Date: December 2024

Line	Description	(a) Customer Count (1) 12-month Average	(b) Customer Count (1) Year End	(c) MMcf Consumption
	Gas Sales			
	Residential Service			
1	Single Family Dwelling A	1,553,444	1,556,850	125,929
2	Multifamily Dwelling A-1	6,499	6,477	3,216
3	Total Residential Service	1,559,943	1,563,327	129,146
	General Service			
4	Small Service GS-1	99,159	100,080	23,099
5	Medium Service GS-2	11,160	10,953	12,881
6	Large Service GS-3	374	367	4,031
7	Outdoor Lighting GL	6	6	1
8	Total General Service	110,699	111,406	40,012
9	Total Gas Sales	1,670,642	1,674,733	169,158
	Customer Choice			
	Residential Service			
10	Single Family Dwelling A	121,430	121,974	10,036
11	Multifamily Dwelling A-1	2,610	2,607	2,016
12	Total Residential Service	124,040	124,581	12,052
	General Service			
13	Small Service GS-1	15,092	15,035	5,104
14	Medium Service GS-2	6,668	6,631	10,350
15	Large Service GS-3	272	271	3,033
16	Total General Service	22,032	21,937	18,486
17	Total Customer Choice	146,072	146,518	30,539
	Transportation			
18	Small Transport ST	1,265	1,268	18,392
19	Large Transport LT	354	356	18,502
20	Extra-large Transport XLT	130	128	25,997
21	Extra-Extra-large Transport XXLT	3	3	17,127
22	Total Transportation	1,752	1,755	80,017
	Aggregation			
	Residential Service			
23	Single Family Dwelling A	78	84	8
24	Multifamily Dwelling A-1	74	74	84
25	Total Residential Service	152	158	92
	General Service			
26	Small Service GS-1	730	727	205
27	Medium Service GS-2	814	808	2,136
28	Large Service GS-3	23	21	171
29	Total General Service	1,567	1,556	2,512
30	Total Aggregation	1,719	1,714	2,604
31	Total Customers & Deliveries	1,820,185	1,824,720	282,317

Notes
(1) Includes contiguous accounts

Schedule E-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2023 Historical Year Operating Revenues
($000)

Case No.: U-21806
Exhibit No.: A-5 (MA-4)
Schedule: E-3
Page: 1 of 1
Witness: MAhmed
Date: December 2024

Line	Description	(a) Tariff	(b) Fuel	(c) Energy Optimization	(d) Operating Revenues
	Gas Sales				
	Residential Service				
1	Single Family Dwelling A	$ 858,950	$ 499,666	$ 48,396	$ 1,407,012
2	Multifamily Dwelling A-1	16,835	12,609	1,248	30,691
3	Total Residential Service	875,785	512,274	49,644	1,437,703
	General Service				
4	Small Service GS-1	218,319	90,456	9,968	318,742
5	Medium Service GS-2	(37,747)	54,230	1,125	17,608
6	Large Service GS-3	11,087	18,383	1,693	31,163
7	Outdoor Lighting GL	4	-	-	4
8	Total General Service	191,664	163,068	12,785	367,518
9	Total Gas Sales	1,067,449	675,343	62,429	1,805,221
	Customer Choice				
	Residential Service				
10	Single Family Dwelling A	66,928	83,293	3,712	153,933
11	Multifamily Dwelling A-1	10,518	10,040	746	21,303
12	Total Residential Service	77,445	93,333	4,458	175,236
	General Service				
13	Small Service GS-1	24,979	30,735	2,127	57,840
14	Medium Service GS-2	41,821	57,876	4,315	104,013
15	Large Service GS-3	12,526	11,830	1,264	25,620
16	Total General Service	79,326	100,441	7,706	187,473
17	Total Customer Choice	156,771	193,774	12,163	362,708
	Transportation				
18	Small Transport ST	36,086	-	7,291	43,378
19	Large Transport LT	27,667	-	1,684	29,351
20	Extra-large Transport XLT	29,961	-	930	30,891
21	Extra-Extra-large Transport XXLT	11,268	-	235	11,502
22	Total Transportation	93,715	-	9,905	115,122
	Aggregation				
	Residential Service				
23	Single Family Dwelling A	50	-	3	53
24	Multifamily Dwelling A-1	435	-	31	466
25	Total Residential Service	485	-	34	519
	General Service				
26	Small Service GS-1	1,028	-	86	1,114
27	Medium Service GS-2	7,866	-	890	8,756
28	Large Service GS-3	584	-	71	655
29	Total General Service	9,478	-	1,047	10,525
30	Total Aggregation	9,963	-	1,081	11,044
31	Total Delivery	$ 1,327,897	$ 869,117	$ 85,579	$ 2,294,095

Schedule: A-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Revenue Deficiency (Sufficiency)
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-11 (HLR-28)
Schedule: A-1
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Rate base	Exhibit No.: A-12 (HLR-31)	11,750,740
2	Adjusted net operating income	Exhibit No.: A-13 (HLR-36)	545,492
3	Overall rate of return	Line 2 / Line 1	4.64%
4	Required rate of return	Source: Exhibit No.: A-14 (MRB-1)	6.22%
5	Income requirement	Line 1 * Line 4	730,838
6	Income deficiency (sufficiency)	Line 5 - Line 2	185,346
7	Revenue conversion factor	Exhibit No.: A-13 (HLR-38)	1.3381
8	Revenue deficiency (sufficiency)	Line 6 * Line 7	248,008

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Ratemaking Basis
For the Projected 12-Month Period Ending October 31, 2026
GAS RESULTS ONLY
($000)

Case No.: U-21806
Exhibit No.: A-11 (HLR-29)
Schedule: A-2
Page: 1 of 3
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) No Rate Relief	(c) Full Rate Relief
1	Operating revenues	2,313,137	2,561,145
2	Operating expenses	1,659,092	1,659,092
3	Pre-tax operating income	654,045	902,053
4	Income taxes	109,851	172,512
5	Net operating income	544,194	729,540
6	Tax effect of pro forma interest on NOI	Included in Line 4	Included in Line 4
7	AFUDC	1,298	1,298
8	Interest charges, net of tax benefit	(215,108)	(215,108)
9	Preferred stock dividends	(643)	(643)
10	Net income available to common stockholders and JDITC	329,741	515,087
11	Return assignable to JDITC	(2,283)	(2,283)
12	Net income available to common stockholders	327,457	512,803
13	Average common equity	5,002,959	5,002,959
14	Earned rate of return on common equity	6.55%	10.25%
15	Authorized rate of return on common equity {1}	10.25%	10.25%

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Ratemaking Basis
For the Projected 12-Month Period Ending October 31, 2026
GAS RESULTS ONLY
($000)

Case No.: U-21806
Exhibit No.: A-11 (HLR-29)
Schedule: A-2
Page: 2 of 3
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) No Rate Relief	(c) Full Rate Relief
	EBIT Interest Coverage Ratio		
16	Pre-tax operating income	654,045	902,053
17	AFUDC	1,298	1,298
18	Total EBIT	655,342	903,350
19	Interest charges, net of tax benefit	215,108	215,108
20	EBIT interest coverage ratio	3.05	4.20
	EBITDA Interest Coverage Ratio		
21	Total EBIT	655,342	903,350
22	Depreciation and amortization	374,164	374,164
23	EBITDA	1,029,507	1,277,514
24	Interest charges, net of tax benefit	215,108	215,108
25	EBITDA interest coverage ratio	4.79	5.94
	FFO Interest Coverage Ratio {2}		
26	Net operating income	544,194	729,540
27	Depreciation and amortization	374,164	374,164
28	Deferred income taxes	111,652	111,652
29	AFUDC	1,298	1,298
30	Other major recurring non-cash items	-	-
31	Interest paid	149,285	149,285
	Less:		
32	Operating lease adjustment to depreciation	-	-
33	Subtotal	1,180,593	1,365,939
34	Interest charges, net of tax benefit	215,108	215,108
35	FFO interest coverage ratio	5.49	6.35
	Overall Fixed Charge Coverage Ratio		
36	Net income available to common stockholders	327,457	512,803
37	Interest charges, net of tax benefit	215,108	215,108
38	Subtotal numerator	542,566	727,912
39	Interest charges, net of tax benefit	215,108	215,108
40	Preferred stock dividends	643	643
41	Subtotal denominator	215,751	215,751
42	Overall fixed charge coverage ratio	2.51	3.37

Schedule: A-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Financial Metrics - Ratemaking Basis
For the Projected 12-Month Period Ending October 31, 2026
GAS RESULTS ONLY
($000)

Case No.: U-21806
Exhibit No.: A-11 (HLR-29)
Schedule: A-2
Page: 3 of 3
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) No Rate Relief	(c) Full Rate Relief
	Cash Flow Coverage of Dividends Ratio		
43	Net income available to common stockholders	327,457	512,803
44	Depreciation and amortization	374,164	374,164
45	Deferred taxes	111,652	111,652
46	Subtotal	813,274	998,620
47	Common dividends {3}	261,966	410,243
48	Cash flow coverage of dividends ratio	3.10	2.43
	Common Dividend Payout Ratio		
49	Common dividends {3}	261,966	410,243
50	Net income available to common stockholders	327,457	512,803
51	Common dividend payout ratio	80%	80%
	Permanent Capitalization		
52	Long term debt, excluding securitization	12,645,149	12,645,149
53	Preferred stock	37,315	37,315
54	Common equity	13,069,567	13,069,567
55	Permanent capitalization	25,752,031	25,752,031
56	Long term debt, excluding securitization	49.10%	49.10%
57	Preferred stock	0.14%	0.14%
58	Common equity	50.75%	50.75%
59	Permanent capitalization	100.00%	100.00%

Notes

{1} The Company is requesting an ROE of 10.25% in this case
{2} FFO = Funds Flow from Operations
{3} Consumers Energy dividends to the parent as a total company. This number represents the Company's 80% dividend policy applied to Net Income Available to Common Stockholders

Schedule: A-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of the Historical and Projected Revenue Requirement
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-11 (HLR-30)
Schedule: A-3
Page: 1 of 1
Witness: HLRayl
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
Line		Source				
No.	Description	Historical Year	Projected Year	Historical Year	Change	Test Year
1	Total utility plant	Exhibit No.: A-2 (HLR-3)	Exhibit No.: A-12 (HLR-31)	12,024,225	2,883,039	14,907,264
2	Depreciation reserve	Exhibit No.: A-2 (HLR-3)	Exhibit No.: A-12 (HLR-31)	(4,015,184)	(650,528)	(4,665,713)
3	Customer advances for construction	Exhibit No.: A-2 (HLR-3)	Exhibit No.: A-12 (HLR-31)	(34,956)	15,796	(19,159)
4	Net utility plant	Sum Lines 1 through 3	Sum Lines 1 through 3	7,974,085	2,248,307	10,222,392
5	Net unamortized manufactured gas plant	Exhibit No.: A-2 (HLR-3)	Exhibit No.: A-12 (HLR-31)	41,147	(21,180)	19,967
6	Working capital	Exhibit No.: A-2 (HLR-3)	Exhibit No.: A-12 (HLR-31)	1,464,009	44,371	1,508,381
7	Rate base	Sum Lines 4 through 6	Sum Lines 4 through 6	9,479,241	2,271,498	11,750,740
8	Rate of return	Exhibit No.: A-4 (HLR-23)	Source: Exhibit No.: A-14 (MRB-1)	5.85%		6.22%
9	Income requirement	Line 7 * Line 8	Line 7 * Line 8	554,667	176,171	730,838
10	Adjusted net operating income	Exhibit No.: A-3 (HLR-9)	Exhibit No.: A-13 (HLR-36)	561,724	(16,232)	545,492
11	Income deficiency (sufficiency)	Line 9 - Line 10	Line 9 - Line 10	(7,057)	192,403	185,346
12	Revenue conversion factor	Exhibit No.: A-3 (HLR-10)	Exhibit No.: A-13 (HLR-38)	1.3381		1.3381
13	Revenue deficiency (sufficiency)	Line 11 * Line 12	Line 11 * Line 12	(9,443)	257,450	248,008

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Fleet Services
($000)

Case No.: U-21806
Exhibit No.: A-12 (CEB-1)
Schedule: B-5.2
Page: 1 of 3
Witness: CEBallinger
Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Period* 12 Mos Ending 12/31/2024	(d) Projected Bridge Period* 10 Mos Ending 10/31/2025	(e) Projected Bridge Period* 22 Mos Ending 10/31/2025	(f) Projected Test Year* 12 Mos Ending 10/31/2026
1	Fleet Vehicle Capital Replacement	9,004	9,664	6,605	16,269	12,923
2	Fleet Vehicle Electrification	0	0	240	240	360
3	Fleet Business Partner Funded	160	23	0	23	0
4	Fleet Tools - Garage	242	238	203	441	249
5	Total Fleet Services Capital	9,405	9,925	7,048	16,973	13,532

		Projected* 10 Mos Ending 10/31/2024	Projected* 12 Mos Ending 10/31/2025	Projected* 12 Mos Ending 10/31/2026	Projected* 34 Mos Ending 10/31/2026
6	Fleet Vehicle Capital Replacement	5,593	10,677	12,923	29,193
7	Fleet Vehicle Electrification	0	240	360	600
8	Fleet Business Partner Funded	23	0	0	23
9	Fleet Tools - Garage	154	287	249	690
10	Total Fleet Services Capital	5,770	11,203	13,532	30,506

**The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level.*

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Fleet Services
($000)

Case No.: U-21806
Exhibit No.: A-12 (CEB-1)
Schedule: B-5.2
Page: 2 of 3
Witness: CEBallinger
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year*			Projected Test Year*
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026
1	Fleet Vehicle Capital Replacement	9,004	9,664	6,605	16,269	12,923
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	8,135	7,731	5,284	13,015	10,338
	Contractor	338	1,643	1,123	2,766	2,197
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other**	531	290	198	488	388
	Contingency	0	0	0	0	0
2	Fleet Vehicle Electrification	0	0	240	240	360
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	0	0	192	192	288
	Contractor	0	0	41	41	61
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other**	0	0	7	7	11
	Contingency	0	0	0	0	0
3	Fleet Business Partner Funded	160	23	0	23	0
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	145	18	0	18	0
	Contractor	15	4	0	4	0
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other**	0	1	0	1	0
	Contingency	0	0	0	0	0
4	Fleet Tools - Garage	242	238	203	441	249
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	242	238	203	441	249
	Contractor	0	0	0	0	0
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other**	0	0	0	0	0
	Contingency	0	0	0	0	0
5	Total Fleet Services Capital	9,405	9,925	7,048	16,973	13,532
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	8,521	7,987	5,679	13,667	10,875
	Contractor	353	1,647	1,164	2,810	2,258
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other**	531	291	205	496	398
	Contingency	0	0	0	0	0

**The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level.*

***Unless noted otherwise, capital "other" costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).*

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Fleet Services
($000)

Case No.: U-21806
Exhibit No.: A-12 (CEB-1)
Schedule: B-5.2
Page: 3 of 3
Witness: CEBallinger
Date: December 2024

	(a)	(b)	(c)	(d)	(e)
		Projected*			
		10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
6	Fleet Vehicle Capital Replacement	5,593	10,677	12,923	29,193
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	4,475	8,541	10,338	23,354
	Contractor	951	1,815	2,197	4,963
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other**	168	320	388	876
	Contingency	0	0	0	0
7	Fleet Vehicle Electrification	0	240	360	600
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	192	288	480
	Contractor	0	41	61	102
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other**	0	7	11	18
	Contingency	0	0	0	0
8	Fleet Business Partner Funded	23	0	0	23
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	19	0	0	19
	Contractor	3	0	0	3
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other**	0	0	0	0
	Contingency	0	0	0	0
9	Fleet Tools - Garage	154	287	249	690
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	154	287	249	690
	Contractor	0	0	0	0
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other**	0	0	0	0
	Contingency	0	0	0	0
10	Total Fleet Services Capital	5,770	11,203	13,532	30,506
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	4,648	9,020	10,875	24,543
	Contractor	954	1,856	2,258	5,068
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other**	168	327	398	894
	Contingency	0	0	0	0

**The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level.*

***Unless noted otherwise, capital "other" costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).*

Schedule: B-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Rate Base
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-12 (HLR-31)
Schedule: B-1
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Total utility plant	Exhibit No.: A-12 (HLR-32)	14,907,264
2	Depreciation reserve	Exhibit No.: A-12 (HLR-33)	(4,665,713)
3	Customer advances for construction	WP-HLR-22	(19,159)
4	Net utility plant	Sum of Lines 1 through 3	10,222,392
5	Net unamortized MGP	Exhibit No.: A-47 (MJF-5), p.2, Line 43	19,967
6	Utility plant rate base	Line 4 + Line 5	10,242,359
7	Working capital	Exhibit No.: A-12 (HLR-34)	1,508,381
8	Total rate base	Sum of Lines 6 through 7	11,750,740

Schedule: B-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Total Utility Plant
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-12 (HLR-32)
Schedule: B-2
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) FERC Account Number	(c) Source	(d) Amount
1	Distribution		WP-HLR-17, Col. (c), Line 1	8,678,876
2	Transmission		WP-HLR-17, Col. (c), Line 2	3,284,338
3	Transmission Other		WP-HLR-17, Col. (c), Line 3	39,341
4	UGS Amortization		WP-HLR-17, Col. (c), Line 4	17,147
5	UGS Depreciation		WP-HLR-17, Col. (c), Line 5	1,597,074
6	UGS Non-Current		WP-HLR-17, Col. (c), Line 6	24,223
7	G-Intangibles		WP-HLR-17, Col. (c), Line 7	45,399
8	C-Intangibles		WP-HLR-17, Col. (c), Line 8	209,660
9	NGP		WP-HLR-17, Col. (c), Line 9	8,665
10	G-GP Structures		WP-HLR-17, Col. (c), Line 10	113,785
11	G-GP Computers		WP-HLR-17, Col. (c), Line 11	6,913
12	G-GP Transportation		WP-HLR-17, Col. (c), Line 12	131,611
13	G-GP Other		WP-HLR-17, Col. (c), Line 13	66,330
14	C-GP Structures		WP-HLR-17, Col. (c), Line 14	166,356
15	C-GP Computers		WP-HLR-17, Col. (c), Line 15	28,810
16	C-GP Transportation		WP-HLR-17, Col. (c), Line 16	75,718
17	C-GP Other		WP-HLR-17, Col. (c), Line 17	90,140
18	Total plant-in-service	101	Sum of Lines 1 through 17	14,584,387
19	Plant purchased or sold	102		-
20	Experimental plant unclassified	103		-
21	Plant leased to others	104		-
22	Completed construction not classified	106		-
23	Plant held of future use	105		-
24	Construction work in progress	107	WP-HLR-18, Col. (c), Line 1	322,877
25	Total utility plant		Sum of Lines 18 through 24	14,907,264

Schedule B-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Depreciation Reserve and Other Deductions
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-12 (HLR-33)
Schedule: B-3
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Distribution	WP-HLR-19, Col. (c), Line 1	3,209,490
2	Transmission	WP-HLR-19, Col. (c), Line 2	595,794
3	Transmission Other	WP-HLR-19, Col. (c), Line 3	19,546
4	UGS Amortization	WP-HLR-19, Col. (c), Line 4	5,977
5	UGS Depreciation	WP-HLR-19, Col. (c), Line 5	247,878
6	UGS Non-Current	WP-HLR-19, Col. (c), Line 6	-
7	G-Intangibles	WP-HLR-19, Col. (c), Line 7	21,461
8	C-Intangibles	WP-HLR-19, Col. (c), Line 8	173,420
9	NGP	WP-HLR-19, Col. (c), Line 9	8,245
10	G-GP Structures	WP-HLR-19, Col. (c), Line 10	16,286
11	G-GP Computers	WP-HLR-19, Col. (c), Line 11	2,725
12	G-GP Transportation	WP-HLR-19, Col. (c), Line 12	138,115
13	G-GP Other	WP-HLR-19, Col. (c), Line 13	25,413
14	C-GP Structures	WP-HLR-19, Col. (c), Line 14	80,763
15	C-GP Computers	WP-HLR-19, Col. (c), Line 15	14,273
16	C-GP Transportation	WP-HLR-19, Col. (c), Line 16	70,064
17	C-GP Other	WP-HLR-19, Col. (c), Line 17	36,261
18	Total depreciation reserve and other deductions	Sum Lines 1 through 17	4,665,713

Schedule: B-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Working Capital
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-12 (HLR-34)
Schedule: B-4
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Historical Year Working Capital	(c) Change	(d) June 2024 13-Mo. Avg. Working Capital	(e) Cash Adjustment	(f) GSU & A/P Adjustment	(g) Prepaid Cloud Computing Adjustment	(h) Pension Adjustment	(i) OPEB Adjustment	(j) Pension/OPEB Volatility Mechanism Adjustment	(k) Accrued Tax Adjustment	(l) SEA Adjustment	(m) Riverside Reg Asset Adjustment	(n) S/4 HANA Implementation Deferral Adjustment	(o) Total Adjustments	(p) Test Year Working Capital
1	Cash, cash equivalents, and restricted cash	8,652	(1,346)	7,306	21,087	-	-	-	-	-	-	-	-	-	21,087	28,393
2	Accounts and notes receivable	136,699	(27,009)	109,689	-	-	-	-	-	-	-	-	-	-	-	109,689
3	Materials and supplies	53,954	2,028	55,983	-	-	-	-	-	-	-	-	-	-	-	55,983
4	Gas stored underground	625,469	(93,220)	532,249	-	(150,213)	-	-	-	-	-	-	-	-	(150,213)	382,036
5	Prepayments	503,604	37,379	540,983	-	-	2,724	-	-	-	-	-	-	-	2,724	543,707
6	Accrued revenue	155,225	(31,312)	123,914	-	-	-	-	-	-	-	-	-	-	-	123,914
7	Deferred taxes	173,309	2,854	176,164	-	-	-	-	-	-	-	-	-	-	-	176,164
8	Deferred debits	310,739	(21,747)	288,992	-	-	-	76,475	93,085	-	-	(1,866)	7,398	2,781	177,872	466,865
9	Total assets	1,967,652	(132,372)	1,835,280	21,087	(150,213)	2,724	76,475	93,085	-	-	(1,866)	7,398	2,781	51,470	1,886,750
10	Accounts payable	263,574	(6,020)	257,553	-	(22,649)	-	-	-	-	-	-	-	-	(22,649)	234,904
11	Customer deposits	13,128	(1,336)	11,793	-	-	-	-	-	-	-	-	-	-	-	11,793
12	Accrued interest	38,112	4,449	42,561	-	-	-	-	-	-	-	-	-	-	-	42,561
13	Dividends payable	11,903	2,877	14,780	-	-	-	-	-	-	-	-	-	-	-	14,780
14	Accrued taxes	140,181	11,076	151,256	-	-	-	-	-	-	(138,858)	-	-	-	(138,858)	12,399
15	Other liabilities	26,309	3,907	30,215	-	-	-	-	-	-	-	-	-	-	-	30,215
16	Deferred credits	10,437	2,265	12,702	-	-	-	-	-	19,016	-	-	-	-	19,016	31,718
17	Total liabilities	503,643	17,217	520,860	-	(22,649)	-	-	-	19,016	(138,858)	-	-	-	(142,491)	378,369
18	Total working capital	1,464,009	(149,589)	1,314,420	21,087	(127,564)	2,724	76,475	93,085	(19,016)	138,858	(1,866)	7,398	2,781	193,961	1,508,381

Notes

Col.(b): Exhibit No.: A-2 (HLR-6)
Col.(c): Col.(d) - Col.(b)
Col.(d): WP-HLR-23
Col.(e): Testimony of Company Witness M. Bleckman
Col.(f): WP-HLR-24
Col.(g): WP-HLR-25
Col.(h): WP-HLR-26
Col.(i): WP-HLR-27
Col.(j): WP-HLR-28
Col.(k): WP-HLR-30
Col.(l): Testimony of Company Witness M. Griffin
Col.(m): WP-HLR-34
Col.(n): WP-HLR-35
Col.(o): Sum of Col. (e) through (n)
Col.(p): Col.(d) + Col.(o)

Schedule: B-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Expenditures Summary
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-12 (HLR-35)
Schedule: B-5
Page: 1 of 1
Witness: HLRayl
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			Historical	Projected				Approved Capital Spending in U-21490 {3}	Projected Capital Spending in U-21490
Line No.	Description	Source	12 Months Ended 12/31/2023	12 Months Ending 12/31/2024	10 Months Ending 10/31/2025	22 Months Ending 10/31/2025	12 Months Ending 10/31/2026	12 Months Ending 9/30/2025	12 Months Ending 9/30/2025
1	Distribution and transmission	See Note {1}	837,567	820,199	717,805	1,538,004	943,729	-	841,499
2	Compression and storage	Exhibit No.: A-12 (TKJ-5), Sch B-5.7	113,046	175,339	184,056	359,395	162,039	-	220,382
3	Information technology and security	Exhibit No.: A-12 (SHB-4), Sch B-5.1	27,620	32,046	28,724	60,770	50,693	-	28,076
4	Fleet	Exhibit No.: A-12 (CEB-1), Sch B-5.2	9,405	9,925	7,048	16,973	13,532	-	9,835
5	Operations support	See Note {2}	17,303	25,579	29,066	54,645	21,145	-	27,085
6	Customer experience and operations	Exhibit No.: A-12 (JRB-1), Sch B-5.3	111	1,078	12	1,090	1,960	-	-
7	Total capital expenditures	Sum of Lines 1 through 6	1,005,053	1,064,167	966,711	2,030,878	1,193,098	-	1,126,877

Notes

{1} Distribution and transmission by witness

Michael P. Griffin	Exhibit No.: A-12 (MPG-2), Sch B-5.5	350,582	313,829	176,781	490,610	219,855
Kristine A. Pascarello	Exhibit No.: A-12 (KAP-3), B-5.8	274,046	301,775	313,809	615,583	402,755
Lincoln D. Warriner	Exhibit No.: A-12 (LDW-1), Sch B-5.9	212,938	204,596	227,215	431,811	321,119

{2} Operations support by witness

Matthew J. Foster	Exhibit No.: A-12 (MJF-12), Sch B-5.4	1,271	631	195	826	238
Quentin A. Guinn	Exhibit No.: A-12 (QAG-1), Sch B-5.6	16,032	24,948	28,871	53,819	20,907

{3} Case No. U-21490 resulted in a settlement agreement that did not state the approved capital spending for all spending categories

Schedule: B-5.3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (JBR-1)
Schedule: B-5.3
Page: 1 of 3
Witness: JRByrom
Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Period 12 Mos Ended 12/31/2024	(d) Projected Bridge Period 10 Mos Ending 10/31/2025	(e) Projected Bridge Period 22 Mos Ending 10/31/2025	(f) Projected Test Year 12 Mos Ending 10/31/2026
1	Customer Billing	111	1,078	12	1,090	0
2	Credit & Assistance	0	0	0	0	1,960
3	Total Customer Experience & Operations Capital	111	1,078	12	1,090	1,960

		Projected 10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
4	Customer Billing	0	1,090	0	1,090
5	Credit & Assistance	0	0	1,960	1,960
6	Total Customer Experience & Operations Capital	0	1,090	1,960	3,050

Schedule: B-5.3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (JRB-1)
Schedule: B-5.3
Page: 2 of 3
Witness: JRByrom
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ended 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026
1	Customer Billing	111	1,078	12	1,090	0
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Material	44	0	0	0	0
	Contractor	66	1,078	12	1,090	0
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0
	Contingency	0	0	0	0	0
2	Credit & Assistance	0	0	0	0	1,960
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Material	0	0	0	0	0
	Contractor	0	0	0	0	1,960
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0
	Contingency	0	0	0	0	0
3	Total Customer Experience & Operations Capital	111	1,078	12	1,090	1,960
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	44	0	0	0	0
	Contractor	66	1,078	12	1,090	1,960
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	0	0	0	0	0
	Contingency	0	0	0	0	0

Schedule: B-5.3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (JRB-1)
Schedule: B-5.3
Page: 3 of 3
Witness: JRByrom
Date: December 2024

Line No	(a) Description	(b) Projected 10 Mos Ending 10/31/2024	(c) Projected 12 Mos Ending 10/31/2025	(d) Projected 12 Mos Ending 10/31/2026	(e) Projected 34 Mos Ending 10/31/2026
4	Customer Billing	0	1,090	0	1,090
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Material	0	0	0	0
	Contractor	0	1,090	0	1,090
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
5	Credit & Assistance	0	0	1,960	1,960
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Material	0	0	0	0
	Contractor	0	0	1,960	1,960
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0
6	Total Customer Experience & Operations Capital	0	1,090	1,960	3,050
	Labor	0	0	0	0
	Capitalized E&S	0	0	0	0
	Materials	0	0	0	0
	Contractor	0	1,090	1,960	3,050
	Non-Labor Overhead	0	0	0	0
	Non-Labor Other	0	0	0	0
	Contingency	0	0	0	0

Schedule: B-5.8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Distribution Plant - Material Condition and Gas Operations Other
Summary of Actual & Projected Gas and Common Capital Expenditures
($000)

Case No.:	U-21806
Exhibit No.:	A-12 (KAP-3)
Schedule:	B-5.8
Page:	1 of 1
Witness:	KAPascarello
Date:	December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Period 12 Mos Ending 12/31/2024	(d) Projected Bridge Period 10 Mos Ending 10/31/2025	(e) Projected Bridge Period 22 Mos Ending 10/31/2025	(f) Projected Test Year 12 Mos Ending 10/31/2026
1	Material Condition	266,297	285,681	301,865	587,546	385,665
2	Gas Operations Other	7,750	16,094	11,943	28,037	17,090
3	Total Capital	274,046	301,775	313,809	615,583	402,755

		Projected 10 Mos Ended 10/31/2024	Projected 12 Mos Ending 10/31/2025	Projected 12 Mos Ending 10/31/2026	Projected 34 Mos Ending 10/31/2026
4	Material Condition	254,378	333,168	385,665	973,211
5	Gas Operations Other	5,823	22,214	17,090	45,127
6	Total Capital	260,201	355,382	402,755	1,018,338

Schedule: B-5.9

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Distribution Plant
($000)

Case No.: U-21806
Exhibit No.: A-12 (LDW-1)
Schedule: B-5.9
Page: 1 of 3
Witness: LDWarriner
Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Period 12 Mos Ending 12/31/2024	(d) Projected Bridge Period 10 Mos Ending 10/31/2025	(e) Projected Bridge Period 22 Mos Ending 10/31/2025	(f) Projected Test Year 12 Mos Ending 10/31/2026
1	New Business	76,320	65,048	52,654	117,702	66,645
2	Asset Relocation	97,685	86,838	75,838	162,676	98,809
3	Regulatory Compliance	34,488	45,217	91,704	136,920	150,311
4	Capacity/Deliverability	4,446	7,493	7,019	14,512	5,354
5	**Total Distribution Plant Capital**	**212,938**	**204,596**	**227,215**	**431,811**	**321,119**

		Projected 10 Mos Ended 10/31/2024	Projected 12 Mos Ending 10/31/2025	Projected 12 Mos Ending 10/31/2026	Projected 34 Mos Ending 10/31/2026
6	New Business	50,519	67,183	66,645	184,347
7	Asset Relocation	72,681	89,995	98,809	261,485
8	Regulatory Compliance	36,873	100,047	150,311	287,232
9	Capacity/Deliverability	5,042	9,470	5,354	19,867
10	**Total Distribution Plant Capital**	**165,115**	**266,696**	**321,119**	**752,930**

Schedule: B-5.9

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Distribution Plant
($000)

Case No.: U-21806
Exhibit No.: A-12 (LDW-1)
Schedule: B-5.9
Page: 2 of 3
Witness: LDWarriner
Date: December 2024

Line No	Description	(a) Historical Year 12 Mos Ended 12/31/2023	(b) Projected Bridge Year 12 Mos Ending 12/31/2024	(c) Projected Bridge Year 10 Mos Ending 10/31/2025	(d) Projected Bridge Year 22 Mos Ending 10/31/2025	(e) Projected Test Year 12 Mos Ending 10/31/2026
1	**New Business**	**76,320**	**65,048**	**52,654**	**117,702**	**66,645**
	Labor	20,320	17,670	15,288	32,958	19,126
	Capitalized Engineering/Supv	20,900	17,869	14,433	32,302	18,275
	Material	7,268	6,851	5,184	12,035	6,644
	Contractor	14,828	12,453	9,279	21,732	11,927
	Non-Labor Overheads	5,121	4,137	3,656	7,793	4,557
	Non-Labor Other	7,883	6,067	4,815	10,882	6,116
	Contingency					
2	**Asset Relocation**	**97,685**	**86,838**	**75,838**	**162,676**	**98,809**
	Labor	13,258	13,998	10,698	24,696	14,082
	Capitalized Engineering/Supv	25,567	22,998	19,715	42,713	25,722
	Material	8,730	9,146	7,073	16,219	9,302
	Contractor	31,904	26,592	24,681	51,273	32,019
	Non-Labor Overheads	2,606	2,580	1,888	4,468	2,494
	Non-Labor Other	15,621	11,524	11,783	23,307	15,190
	Contingency					
3	**Regulatory Compliance**	**34,488**	**45,217**	**91,704**	**136,920**	**150,311**
	Labor	6,051	7,332	11,015	18,347	16,292
	Capitalized Engineering/Supv	8,445	10,926	21,840	32,766	35,672
	Material	11,687	14,708	18,916	33,624	25,930
	Contractor	2,902	5,172	23,083	28,255	43,567
	Non-Labor Overheads	410	347	544	891	883
	Non-Labor Other	4,992	6,732	16,306	23,038	27,968
	Contingency					
4	**Capacity/Deliverability**	**4,446**	**7,493**	**7,019**	**14,512**	**5,354**
	Labor	430	677	635	1,312	484
	Capitalized Engineering/Supv	1,096	1,849	1,732	3,581	1,321
	Material	563	884	829	1,713	632
	Contractor	1,495	2,644	2,477	5,120	1,889
	Non-Labor Overheads	65	88	82	170	63
	Non-Labor Other	796	1,351	1,265	2,616	965
	Contingency					
5	**Total Distribution Capital**	**212,938**	**204,596**	**227,215**	**431,811**	**321,119**
	Labor	40,059	39,677	37,635	77,312	49,985
	Capitalized Engineering/Supv	56,008	53,643	57,720	111,363	80,990
	Material	28,248	31,589	32,002	63,591	42,508
	Contractor	51,129	46,861	59,520	106,381	89,401
	Non-Labor Overheads	8,202	7,152	6,170	13,321	7,997
	Non-Labor Other	29,292	25,674	34,169	59,843	50,239
	Contingency	0	0	0	0	0

Note: capital “non-labor other” costs include expenses such as pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, non-labor material loadings, contributions/reimbursements and business expenses. WP-LDW-2 page 7 of 7 provides additional details on "non-labor other" costs. Confidence intervals are not used to prepare projections for the above programs.

Schedule: B-5.9

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Distribution Plant
($000)

Case No.: U-21806
Exhibit No.: A-12 (LDW-1)
Schedule: B-5.9
Page: 3 of 3
Witness: LDWarriner
Date: December 2024

Line No	(a)	(b)	(c)	(d)	(e)
		Projected			
		10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
6	**New Business**	**50,519**	**67,183**	**66,645**	**184,347**
	Labor	13,680	19,277	19,126	52,084
	Capitalized Engineering/Supv	13,879	18,422	18,275	50,577
	Material	5,336	6,698	6,644	18,679
	Contractor	9,707	12,026	11,927	33,659
	Non-Labor Overheads	3,199	4,593	4,557	12,350
	Non-Labor Other	4,716	6,166	6,116	16,999
	Contingency				
7	**Asset Relocation**	**72,681**	**89,995**	**98,809**	**261,485**
	Labor	12,000	12,696	14,082	38,778
	Capitalized Engineering/Supv	19,318	23,396	25,722	68,435
	Material	7,825	8,394	9,302	25,521
	Contractor	21,986	29,287	32,019	83,292
	Non-Labor Overheads	2,228	2,240	2,494	6,962
	Non-Labor Other	9,325	13,982	15,190	38,497
	Contingency				
8	**Regulatory Compliance**	**36,873**	**100,047**	**150,311**	**287,232**
	Labor	6,174	12,173	16,292	34,639
	Capitalized Engineering/Supv	8,931	23,835	35,672	68,438
	Material	12,494	21,129	25,930	59,553
	Contractor	3,588	24,667	43,567	71,822
	Non-Labor Overheads	317	574	883	1,774
	Non-Labor Other	5,369	17,669	27,968	51,006
	Contingency				
9	**Capacity/Deliverability**	**5,042**	**9,470**	**5,354**	**19,867**
	Labor	456	856	484	1,796
	Capitalized Engineering/Supv	1,244	2,337	1,321	4,903
	Material	595	1,118	632	2,345
	Contractor	1,779	3,341	1,889	7,009
	Non-Labor Overheads	59	111	63	233
	Non-Labor Other	909	1,707	965	3,581
	Contingency				
10	**Total Distribution Capital**	**165,115**	**266,696**	**321,119**	**752,930**
	Labor	32,310	45,002	49,985	127,297
	Capitalized Engineering/Supv	43,372	67,991	80,990	192,352
	Material	26,251	37,340	42,508	106,098
	Contractor	37,060	69,321	89,401	195,782
	Non-Labor Overheads	5,803	7,518	7,997	21,318
	Non-Labor Other	20,319	39,524	50,239	110,082
	Contingency				

Note: capital “non-labor other” costs include expenses such as pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, non-labor material loadings, contributions/reimbursements and business expenses. WP-LDW-2 page 7 of 7 provides additional details on "non-labor other" costs. Confidence intervals are not used to prepare projections for the above programs.

Schedule: B-5.4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Gas Corporate Services Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (MJF-12)
Schedule: B-5.4
Page: 1 of 1
Witness: MJFoster
Date: December 2024

Line No	Description	(a)	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Year 12 Mos Ending 12/31/2024	(d) Projected Bridge Year 10 Mos Ending 10/31/2025	(e) Projected Bridge Year 22 Mos Ending 10/31/2025	(f) Projected Test Year 12 Mos Ending 10/31/2026
						(c) + (d)	
1	Corporate Capital		1,271	631	195	826	238
	Contractor		675	314	17	331	20
	Labor		99	55	20	75	24
	Materials		82	177	151	328	185
	Business Expenses		415	85	7	92	9
	Contingency		-	-	-	-	-
	Other (Loadings, Chargebacks)		-	-	-	-	-
2	**Total Capital**		1,271	631	195	826	238

		Projected 10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
3	Corporate Capital	593	233	238	1,064
	Contractor	311	20	20	351
	Labor	50	23	24	97
	Materials	148	181	185	514
	Business Expenses	84	9	9	102
	Contingency	-	-	-	-
	Other (Loadings, Chargebacks)	-	-	-	-
4	**Total Capital**	593	233	238	1,064

Schedule: B-5.5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures Transmission & Distribution Plant
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (MPG-2) Revised
Schedule: B-5.5
Page: 1 of 1
Witness: MPGriffin
Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Period 12 Mos Ending 12/31/2024	(d) Projected Bridge Period 10 Mos Ending 10/31/2025	(e) Projected Bridge Period 22 Mos Ending 10/31/2025	(f) Projected Test Year 12 Mos Ending 10/31/2026
1	Asset Relocation	6,168	17,389	19,138	36,527	24,726
2	Regulatory Compliance	36,139	26,078	24,285	50,362	24,807
3	Capacity/Deliverability	308,275	270,203	133,076	403,278	170,372
4	Total Capital	350,582	313,669	176,499	490,168	219,905

		Projected 10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
5	Asset Relocation	15,150	21,377	24,726	61,253
6	Regulatory Compliance	27,176	23,187	24,807	75,170
7	Capacity/Deliverability	245,755	157,965	170,372	574,092
8	Total Capital	288,081	202,529	219,905	710,515

Schedule: B-5.5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures Transmission & Distribution Plant
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (MPG-2)
Schedule: B-5.5
Page: 1 of 1
Witness: MPGriffin
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Period			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026
1	Asset Relocation	6,168	17,389	19,138	36,527	24,726
2	Regulatory Compliance	36,139	26,078	24,285	50,362	24,807
3	Capacity/Deliverability	308,275	270,362	133,358	403,720	170,322
4	Total Capital	350,582	313,829	176,781	490,610	219,855

		Projected			
		10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
5	Asset Relocation	15,150	21,377	24,726	61,253
6	Regulatory Compliance	27,176	23,187	24,807	75,170
7	Capacity/Deliverability	245,755	157,965	170,322	574,042
8	Total Capital	288,081	202,529	219,855	710,464

Schedule: B-5.6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Capital Expenditures
Operations Support
($000)

Case No.: U-21806
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.6
Page: 1 of 3
Witness: QAGuinn
Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Period* 12 Mos Ending 12/31/2024	(d) Projected Bridge Period* 10 Mos Ending 10/31/2025	(e) Projected Bridge Period* 22 Mos Ending 10/31/2025	(f) Projected Test Year* 12 Mos Ending 10/31/2026
1	Asset Preservation	15,858	24,289	28,382	52,671	20,255
2	Other Equipment	175	660	489	1,148	652
3	Total Operations Support Capital	16,032	24,948	28,871	53,819	20,907

		Projected* 10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
4	Asset Preservation	17,309	35,362	20,255	72,926
5	Other Equipment	329	820	652	1,800
6	Total Operations Support Capital	17,637	36,182	20,907	74,726

**The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level.*

Schedule: B-5.6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Operations Support
($000)

Case No.: U-21806
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.6
Page: 2 of 3
Witness: QAGuinn
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year*			Projected Test Year*
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026
1	Asset Preservation	15,858	24,289	28,382	52,671	20,255
	Labor	1,269	1,457	1,703	3,160	1,215
	Capitalized E&S	0	0	0	0	0
	Materials	634	1,457	1,703	3,160	1,215
	Contractor	13,003	20,160	23,557	43,717	16,812
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other**	951	1,214	1,419	2,634	1,013
	Contingency	0	0	0	0	0
2	Other Equipment	175	660	489	1,148	652
	Labor	0	0	0	0	0
	Capitalized E&S	0	0	0	0	0
	Materials	143	528	391	919	521
	Contractor	4	99	73	172	98
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other**	28	33	24	57	33
	Contingency	0	0	0	0	0
3	Total Operations Support Capital	16,032	24,948	28,871	53,819	20,907
	Labor	1,269	1,457	1,703	3,160	1,215
	Capitalized E&S	0	0	0	0	0
	Materials	777	1,985	2,094	4,079	1,737
	Contractor	13,007	20,259	23,630	43,889	16,909
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other**	979	1,247	1,444	2,691	1,045
	Contingency	0	0	0	0	0

**The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level.*

***Unless noted otherwise, capital "other" costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).*

Schedule: B-5.6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Operations Support
($000)

Case No.: U-21806
Exhibit No.: A-12 (QAG-1)
Schedule: B-5.6
Page: 3 of 3
Witness: QAGuinn
Date: December 2024

(a)	(b)	(c)	(d)	(e)
	Projected*			
	10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
4 Asset Preservation	17,309	35,362	20,255	72,926
Labor	1,039	2,122	1,215	4,376
Capitalized E&S	0	0	0	0
Materials	1,039	2,122	1,215	4,376
Contractor	14,366	29,351	16,812	60,528
Non-Labor Overhead	0	0	0	0
Non-Labor Other**	865	1,768	1,013	3,646
Contingency	0	0	0	0
5 Other Equipment	329	820	652	1,800
Labor	0	0	0	0
Capitalized E&S	0	0	0	0
Materials	263	656	521	1,440
Contractor	49	123	98	270
Non-Labor Overhead	0	0	0	0
Non-Labor Other**	16	41	33	90
Contingency	0	0	0	0
6 Total Operations Support Capital	17,637	36,182	20,907	74,726
Labor	1,039	2,122	1,215	4,376
Capitalized E&S	0	0	0	0
Materials	1,301	2,778	1,737	5,816
Contractor	14,415	29,474	16,909	60,798
Non-Labor Overhead	0	0	0	0
Non-Labor Other**	882	1,809	1,045	3,736
Contingency	0	0	0	0

**The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level.*

***Unless noted otherwise, capital "other" costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).*

Schedule B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Information Technology
Summary of Actual & Projected Gas and Common Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (SHB-4)
Schedule: B-5.1
Page: 1 of 2
Witness: SHBaker
Date: December 2024

Line No.	(a) Description	(b) Historical 12 Mos Ended 12/31/2023	(c) Capital Expenditures Projected Bridge Year 12 Mos Ending 12/31/2024	(d) Projected Bridge Year 10 Mos Ending 10/31/2025	(e) Projected Bridge Year 22 Mos Ending 10/31/2025	(f) Projected Test Year 12 mos. Ending 10/31/2026
1	**Corporate**	**775**	**684**	**1,136**	**1,820**	**1,187**
	Labor	101	436	688	1,124	695
	Software	98	111	0	111	0
	Materials	0	0	10	10	38
	Contractor	488	117	63	180	75
	Non-Labor Overhead	26	4	63	67	56
	Non-Labor Other	62	15	311	327	323
	Contingency	0	0	0	0	0
2	**Customer**	**1,096**	**686**	**2,550**	**3,235**	**2,371**
	Labor	214	126	1,122	1,249	925
	Software	3	78	0	78	0
	Materials	9	0	0	0	0
	Contractor	714	436	736	1,172	872
	Non-Labor Overhead	55	15	88	103	79
	Non-Labor Other	101	30	603	633	496
	Contingency	0	0	0	0	0
3	**Electric & Gas Shared**	**2,020**	**1,943**	**591**	**2,534**	**586**
	Labor	403	995	165	1,159	190
	Software	412	213	0	213	0
	Materials	22	99	20	119	32
	Contractor	902	531	222	753	168
	Non-Labor Overhead	74	13	30	43	40
	Non-Labor Other	206	93	154	247	155
	Contingency	0	0	0	0	0
4	**Gas**	**4,535**	**9,811**	**11,741**	**21,552**	**10,180**
	Labor	330	1,499	2,651	4,150	2,930
	Software	1,592	1,198	2,937	4,135	1,123
	Materials	994	949	329	1,278	2,753
	Contractor	1,323	5,583	3,710	9,292	1,393
	Non-Labor Overhead	69	40	587	627	328
	Non-Labor Other	226	543	1,527	2,069	1,653
	Contingency	0	0	0	0	0
5	**IT/Digital Foundation**	**12,847**	**12,734**	**8,946**	**21,680**	**32,467**
	Labor	926	1,827	931	2,758	4,111
	Software	3,784	534	68	602	7,448
	Materials	6,291	6,202	5,953	12,156	9,590
	Contractor	1,423	3,642	1,441	5,083	8,182
	Non-Labor Overhead	75	91	110	201	588
	Non-Labor Other	349	438	442	880	2,549
	Contingency	0	0	0	0	0
6	**Security**	**6,348**	**6,188**	**3,762**	**9,950**	**3,902**
	Labor	1,196	709	692	1,401	392
	Software	203	502	73	576	1,335
	Materials	1,148	1,155	1,336	2,491	1,039
	Contractor	3,293	3,589	1,131	4,720	686
	Non-Labor Overhead	73	7	285	292	219
	Non-Labor Other	435	226	244	470	230
	Contingency	0	0	0	0	0
7	**Total Information Technology Capital**	**27,620**	**32,046**	**28,724**	**60,770**	**50,693**
	Labor	3,170	5,593	6,248	11,841	9,242
	Software	6,093	2,637	3,078	5,715	9,906
	Materials	8,463	8,404	7,649	16,054	13,453
	Contractor	8,142	13,898	7,303	21,201	11,377
	Non-Labor Overhead	373	169	1,164	1,334	1,310
	Non-Labor Other	1,380	1,344	3,281	4,625	5,406
	Contingency	0	0	0	0	0

The Company fully plans to perform the projects included in the Information Technology cost projections, but the projections do not incorporate a specific confidence level. These costs were not projected using confidence levels. Rough Order of Magnitude (ROM) estimates have been reduced by 20% as discussed in my testimony.

Schedule B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Information Technology
Summary of Actual & Projected Gas and Common Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (SHB-4)
Schedule: B-5.1
Page: 2 of 2
Witness: SHBaker
Date: December 2024

	(a)	(b)	(c)	(d)	(e)
		Projected			
		10 mos. Ending 10/31/2024	12 mos. Ending 10/31/2025	12 mos. Ending 10/31/2026	34 mos. Ending 10/31/2026
8	**Corporate**	**380**	**1,440**	**1,187**	**3,007**
	Labor	132	993	695	1,819
	Software	111	0	0	111
	Materials	0	10	38	48
	Contractor	117	63	75	256
	Non-Labor Overhead	4	63	56	123
	Non-Labor Other	15	311	323	650
	Contingency	0	0	0	0
9	**Customer**	**587**	**2,649**	**2,371**	**5,607**
	Labor	126	1,122	925	2,174
	Software	78	0	0	78
	Materials	0	0	0	0
	Contractor	337	835	872	2,044
	Non-Labor Overhead	15	88	79	182
	Non-Labor Other	30	603	496	1,129
	Contingency	0	0	0	0
10	**Electric & Gas Shared**	**1,525**	**1,009**	**586**	**3,120**
	Labor	610	549	190	1,349
	Software	215	(2)	0	213
	Materials	99	20	32	151
	Contractor	495	259	168	922
	Non-Labor Overhead	13	30	40	83
	Non-Labor Other	93	153	155	402
	Contingency	0	0	0	0
11	**Gas**	**8,790**	**12,762**	**10,180**	**31,732**
	Labor	1,165	2,985	2,930	7,079
	Software	1,077	3,058	1,123	5,258
	Materials	949	329	2,753	4,031
	Contractor	5,115	4,178	1,393	10,686
	Non-Labor Overhead	40	587	328	955
	Non-Labor Other	445	1,624	1,653	3,723
	Contingency	0	0	0	0
12	**IT/Digital Foundation**	**10,880**	**10,800**	**32,467**	**54,147**
	Labor	1,195	1,563	4,111	6,868
	Software	439	163	7,448	8,050
	Materials	5,388	6,768	9,590	21,746
	Contractor	3,421	1,662	8,182	13,264
	Non-Labor Overhead	91	110	588	789
	Non-Labor Other	346	534	2,549	3,429
	Contingency	0	0	0	0
13	**Security**	**5,749**	**4,201**	**3,902**	**13,852**
	Labor	898	503	392	1,793
	Software	502	73	1,335	1,911
	Materials	870	1,621	1,039	3,530
	Contractor	3,270	1,451	686	5,406
	Non-Labor Overhead	7	285	219	511
	Non-Labor Other	203	267	230	699
	Contingency	0	0	0	0
14	**Total Capital**	**27,910**	**32,860**	**50,693**	**111,464**
	Labor	4,127	7,715	9,242	21,083
	Software	2,422	3,293	9,906	15,621
	Materials	7,305	8,749	13,453	29,507
	Contractor	12,754	8,447	11,377	32,578
	Non-Labor Overhead	169	1,164	1,310	2,644
	Non-Labor Other	1,133	3,493	5,406	10,031
	Contingency	0	0	0	0

The Company fully plans to perform the projects included in the Information Technology cost projections, but the projections do not incorporate a specific confidence level. These costs were not projected using confidence levels. Rough Order of Magnitude (ROM) estimates have been reduced by 20% as discussed in my testimony.

Schedule: B-5.7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Gas Compression and Gas Storage
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (TKJ-5)
Schedule: B-5.7
Page: 1 of 6
Witness: TKJoyce
Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Period 12 Mos Ending 12/31/2024	(d) Projected Bridge Period 10 Mos Ending 10/31/2025	(e) Projected Bridge Period 22 Mos Ending 10/31/2025	(f) Projected Test Year 12 Mos Ending 10/31/2026
1	Freedom Upgrade Project	8,413	726	0	726	0
2	Compression	39,197	62,267	44,597	106,864	66,198
3	Storage	6,765	28,548	35,690	64,238	25,234
4	New Well	11,403	17,202	28,004	45,205	32,296
5	Well Rehabilitation	31,031	23,681	22,341	46,022	7,498
6	Storage Pipeline Replacement	3,550	14,836	24,398	39,233	20,930
7	Well Data Acquisition	239	203	3,671	3,875	4,568
8	Riverside Field Retirement	12,449	25,439	23,756	49,195	3,504
9	Safety Valve Installation	0	2,438	1,599	4,037	1,811
10	Total Capital Expenditures	113,046	175,339	184,056	359,395	162,039

		Projected 10 Mos Ending 10/31/2024	Projected 12 Mos Ending 10/31/2025	Projected 12 Mos Ending 10/31/2026	Projected 34 Mos Ending 10/31/2026
11	Freedom Upgrade Project	579	147	0	726
12	Compression	39,551	67,312	66,198	173,062
13	Storage	23,302	40,935	25,234	89,472
14	New Well	10,961	34,244	32,296	77,501
15	Well Rehabilitation	23,303	22,720	7,498	53,521
16	Storage Pipeline Replacement	11,961	27,272	20,930	60,163
17	Well Data Acquisition	38	3,837	4,568	8,443
18	Riverside Field Retirement	22,084	27,111	3,504	52,699
19	Safety Valve Installation	2,527	1,510	1,811	5,848
20	Total Capital Expenditures	134,307	225,089	162,039	521,434

Schedule: B-5.7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Gas Compression and Gas Storage
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (TKJ-5)
Schedule: B-5.7
Page: 2 of 6
Witness: TKJoyce
Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Period 12 Mos Ending 12/31/2024	(d) Projected Bridge Period 10 Mos Ending 10/31/2025	(e) Projected Bridge Period 22 Mos Ending 10/31/2025	(f) Projected Test Year 12 Mos Ending 10/31/2026
1	Freedom Upgrade Project	8,413	726	0	726	0
2	Freedom Compression	239	232	424	656	153
3	Muskegon River Compression	4,210	21,435	14,576	36,011	14,126
4	Northville Compression	2,382	2,786	3,890	6,676	11,055
5	Overisel Compression	28,178	24,925	17,025	41,950	15,561
6	Ray Compression	1,657	7,010	3,563	10,573	4,476
7	St Clair Compression	2,074	3,610	3,623	7,234	14,502
8	White Pigeon Compression	457	2,268	1,497	3,765	6,324
9	Marion Storage Fields	2,547	1,562	3,082	4,644	13,501
10	Northville Storage Field	1,382	8,453	25,351	33,804	4,672
11	Overisel Storage Fields	1,500	4,877	1,742	6,619	4,526
12	Ray Storage Fields	81	4,061	5,215	9,275	791
13	St Clair Storage Fields	1,255	9,595	301	9,896	1,743
14	Storage New Wells	11,403	17,202	28,004	45,205	32,296
15	Well Rehabilitation	31,031	23,681	22,341	46,022	7,498
16	Storage Pipeline Replacement	3,550	14,836	24,398	39,233	20,930
17	Well Data Acquisition	239	203	3,671	3,875	4,568
18	Riverside Field Retirement	12,449	25,439	23,756	49,195	3,504
19	Safety Valve Installation	0	2,438	1,599	4,037	1,811
20	Total Capital Expenditures	113,046	175,339	184,056	359,395	162,039

Unless noted otherwise, capital “other” costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.). This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were

Schedule: B-5.7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Gas Compression and Gas Storage
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (TKJ-5)
Schedule: B-5.7
Page: 3 of 6
Witness: TKJoyce
Date: December 2024

Line No	Description	Historical Year 12 Mos Ended 12/31/2023	Projected Bridge Year 12 Mos Ending 12/31/2024	Projected Bridge Year 10 Mos Ending 10/31/2025	Projected Bridge Year 22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
	(a)	(b)	(c)	(d)	(e)	(f)
1	**Freedom Upgrade Project**	**8,413**	**726**	**0**	**726**	**0**
4%	Labor	337	31	0	31	0
15%	Capitalized Engineering/Supv	1,245	107	0	107	0
1%	Materials	90	8	0	8	0
74%	Contractor	6,265	539	0	539	0
0%	Non-Labor Overhead	12	1	0	1	0
6%	Non-Labor Other	464	40	0	40	0
2	**Freedom Compression**	**239**	**232**	**424**	**656**	**153**
5%	Labor	8	11	19	30	7
1%	Capitalized Engineering/Supv	0	3	5	7	2
80%	Materials	224	186	340	527	123
9%	Contractor	(4)	22	40	61	14
0%	Non-Labor Overhead	0	0	0	0	0
5%	Non-Labor Other	11	11	20	30	7
3	**Muskegon River Compression**	**4,210**	**21,435**	**14,576**	**36,011**	**14,126**
11%	Labor	629	2,336	1,589	3,925	1,540
12%	Capitalized Engineering/Supv	593	2,527	1,718	4,246	1,666
5%	Materials	153	1,039	707	1,746	685
65%	Contractor	2,451	13,835	9,408	23,243	9,118
0%	Non-Labor Overhead	15	38	26	64	25
8%	Non-Labor Other	369	1,659	1,128	2,788	1,094
4	**Northville Compression**	**2,382**	**2,786**	**3,890**	**6,676**	**11,055**
11%	Labor	248	295	412	707	1,171
13%	Capitalized Engineering/Supv	354	361	504	865	1,432
10%	Materials	177	288	403	691	1,144
58%	Contractor	1,427	1,627	2,271	3,898	6,455
0%	Non-Labor Overhead	5	4	6	10	17
8%	Non-Labor Other	170	211	295	505	837
5	**Overisel Compression**	**28,178**	**24,925**	**17,025**	**41,950**	**15,561**
5%	Labor	1,086	1,191	814	2,005	744
13%	Capitalized Engineering/Supv	4,085	3,316	2,265	5,581	2,070
23%	Materials	7,533	5,855	3,999	9,855	3,655
50%	Contractor	13,676	12,463	8,513	20,976	7,781
0%	Non-Labor Overhead	(4)	7	5	11	4
8%	Non-Labor Other	1,803	2,092	1,429	3,522	1,306

Unless noted otherwise, capital “other” costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and
This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop these cost projections.

Schedule: B-5.7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Gas Compression and Gas Storage
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (TKJ-5)
Schedule: B-5.7
Page: 4 of 6
Witness: TKJoyce
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026
6	**Ray Compression**	**1,657**	**7,010**	**3,563**	**10,573**	**4,476**
7%	Labor	77	518	263	782	331
11%	Capitalized Engineering/Supv	227	760	386	1,146	485
7%	Materials	45	487	247	734	311
68%	Contractor	1,205	4,772	2,425	7,198	3,047
0%	Non-Labor Overhead	1	20	10	31	13
6%	Non-Labor Other	103	452	230	682	289
7	**St Clair Compression**	**2,074**	**3,610**	**3,623**	**7,234**	**14,502**
7%	Labor	148	262	262	524	1,051
12%	Capitalized Engineering/Supv	295	450	452	902	1,807
16%	Materials	83	588	591	1,179	2,364
57%	Contractor	1,418	2,074	2,081	4,155	8,329
0%	Non-Labor Overhead	0	8	8	16	32
6%	Non-Labor Other	130	229	230	459	920
8	**White Pigeon Compression**	**457**	**2,268**	**1,497**	**3,765**	**6,324**
17%	Labor	63	385	254	639	1,073
13%	Capitalized Engineering/Supv	64	284	187	471	791
3%	Materials	14	68	45	113	191
55%	Contractor	277	1,257	830	2,087	3,505
0%	Non-Labor Overhead	0	1	0	1	2
12%	Non-Labor Other	38	274	181	454	763
9	**Marion Storage Fields**	**2,547**	**1,562**	**3,082**	**4,644**	**13,501**
7%	Labor	168	103	203	305	888
14%	Capitalized Engineering/Supv	363	216	427	643	1,869
13%	Materials	338	200	395	596	1,732
58%	Contractor	1,471	901	1,778	2,679	7,788
0%	Non-Labor Overhead	6	4	7	11	31
9%	Non-Labor Other	201	138	272	410	1,193
10	**Northville Storage Field**	**1,382**	**8,453**	**25,351**	**33,804**	**4,672**
5%	Labor	83	460	1,381	1,841	254
8%	Capitalized Engineering/Supv	132	689	2,065	2,753	381
0%	Materials	0	0	0	0	0
63%	Contractor	1,105	5,353	16,054	21,407	2,959
0%	Non-Labor Overhead	0	0	0	0	0
23%	Non-Labor Other	62	1,951	5,852	7,803	1,078

Unless noted otherwise, capital “other” costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and

This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop these cost projections.

Schedule: B-5.7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Gas Compression and Gas Storage
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (TKJ-5)
Schedule: B-5.7
Page: 5 of 6
Witness: TKJoyce
Date: December 2024

Line No	Description	Historical Year 12 Mos Ended 12/31/2023	Projected Bridge Year 12 Mos Ending 12/31/2024	Projected Bridge Year 10 Mos Ending 10/31/2025	Projected Bridge Year 22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
	(a)	(b)	(c)	(d)	(e)	(f)
11	**Overisel Storage Fields**	**1,500**	**4,877**	**1,742**	**6,619**	**4,526**
11%	Labor	143	528	189	717	490
14%	Capitalized Engineering/Supv	220	660	236	896	612
6%	Materials	81	309	111	420	287
57%	Contractor	932	2,793	997	3,790	2,592
0%	Non-Labor Overhead	1	5	2	7	5
12%	Non-Labor Other	123	581	208	789	540
12	**Ray Storage Fields**	**81**	**4,061**	**5,215**	**9,275**	**791**
5%	Labor	22	193	247	440	38
10%	Capitalized Engineering/Supv	11	417	535	952	81
55%	Materials	0	2,226	2,859	5,086	434
23%	Contractor	38	952	1,223	2,175	186
0%	Non-Labor Overhead	0	10	12	22	2
6%	Non-Labor Other	10	263	338	601	51
13	**St Clair Storage Fields**	**1,255**	**9,595**	**301**	**9,896**	**1,743**
8%	Labor	204	803	25	828	146
10%	Capitalized Engineering/Supv	176	1,005	31	1,036	183
21%	Materials	374	2,000	63	2,063	363
54%	Contractor	371	5,165	162	5,327	938
0%	Non-Labor Overhead	2	25	1	26	5
6%	Non-Labor Other	127	597	19	616	108
14	**Storage New Wells**	**11,403**	**17,202**	**28,004**	**45,205**	**32,296**
4%	Labor	366	686	1,116	1,801	1,287
13%	Capitalized Engineering/Supv	1,739	2,309	3,760	6,069	4,336
7%	Materials	858	1,285	2,092	3,378	2,413
62%	Contractor	7,471	10,670	17,370	28,041	20,033
0%	Non-Labor Overhead	5	7	12	20	14
13%	Non-Labor Other	964	2,244	3,653	5,897	4,213
15	**Well Rehabilitation**	**31,031**	**23,681**	**22,341**	**46,022**	**7,498**
5%	Labor	1,668	1,300	1,226	2,526	412
14%	Capitalized Engineering/Supv	4,588	3,259	3,074	6,333	1,032
2%	Materials	589	493	465	958	156
71%	Contractor	21,722	16,842	15,889	32,731	5,333
0%	Non-Labor Overhead	24	18	17	36	6
7%	Non-Labor Other	2,442	1,769	1,669	3,438	560

Unless noted otherwise, capital “other” costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and
This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop these cost projections.

Schedule: B-5.7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Gas Compression and Gas Storage
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.:	U-21806
Exhibit No.:	A-12 (TKJ-5)
Schedule:	B-5.7
Page:	6 of 6
Witness:	TKJoyce
Date:	December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026
16	**Storage Pipeline Replacement**	**3,550**	**14,836**	**24,398**	**39,233**	**20,930**
8%	Labor	439	1,182	1,944	3,127	1,668
12%	Capitalized Engineering/Supv	518	1,761	2,896	4,657	2,485
34%	Materials	824	5,023	8,261	13,284	7,087
37%	Contractor	1,480	5,493	9,033	14,526	7,749
0%	Non-Labor Overhead	14	46	75	121	65
9%	Non-Labor Other	275	1,330	2,187	3,518	1,877
17	**Well Data Acquisition**	**239**	**203**	**3,671**	**3,875**	**4,568**
33%	Labor	76	67	1,213	1,280	1,509
14%	Capitalized Engineering/Supv	33	28	502	530	624
28%	Materials	71	57	1,037	1,095	1,291
10%	Contractor	23	21	382	403	475
0%	Non-Labor Overhead	0	0	0	0	0
15%	Non-Labor Other	35	30	538	568	670
18	**Riverside Field Retirement**	**12,449**	**25,439**	**23,756**	**49,195**	**3,504**
8%	Labor	831	1,933	1,805	3,739	266
24%	Capitalized Engineering/Supv	3,203	6,112	5,708	11,820	842
13%	Materials	2,436	3,312	3,093	6,406	456
36%	Contractor	3,791	9,105	8,503	17,609	1,254
0%	Non-Labor Overhead	16	71	66	137	10
19%	Non-Labor Other	2,172	4,905	4,580	9,485	676
19	**Safety Valve Installation**	**0**	**2,438**	**1,599**	**4,037**	**1,811**
12%	Labor	0	292	191	483	217
8%	Capitalized Engineering/Supv	0	207	136	343	154
0%	Materials	0	0	0	0	0
74%	Contractor	0	1,806	1,184	2,989	1,341
0%	Non-Labor Overhead	0	0	0	0	0
5%	Non-Labor Other	0	134	88	222	99
20	Total Capital	113,046	175,339	184,056	359,395	162,039
	Labor	6,594	12,576	13,154	25,731	13,090
	Capitalized Engineering/Supv	17,847	24,469	24,886	49,355	20,851
	Materials	13,891	23,428	24,709	48,138	22,692
	Contractor	65,117	95,690	98,143	193,833	88,897
	Non-Labor Overhead	98	264	248	512	228
	Non-Labor Other	9,499	18,911	22,916	41,827	16,281

Unless noted otherwise, capital “other” costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee
This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop these cost projections.

Schedule: C-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Net Operating Income
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-13 (HLR-36)
Schedule: C-1
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Sales revenues	Exhibit No.: A-13 (HLR-39)	2,182,075
2	Transportation revenues	Exhibit No.: A-13 (HLR-39)	102,396
3	Other revenues	Exhibit No.: A-13 (HLR-39)	28,666
4	Total operating revenues	Sum of Lines 1 through 3	2,313,137
5	Cost of gas sold	Exhibit No.: A-13 (HLR-40)	737,588
6	LAUF	Exhibit No.: A-13 (HLR-41), Line 1	12,709
7	Company use gas	Exhibit No.: A-13 (HLR-41), Line 2	5,502
8	Operations and maintenance	Exhibit No.: A-13 (HLR-41), Line 34	297,904
9	Depreciation	Exhibit No.: A-13 (HLR-43), Line 18	374,164
10	Amortization	Exhibit No.: A-13 (HLR-43), Line 21	10,239
11	Property taxes	Exhibit No.: A-13 (HLR-44), Line 1	201,200
12	General taxes	Exhibit No.: A-13 (HLR-44), Line 6 + Line 15	19,785
13	Other (local) taxes	Exhibit No.: A-13 (HLR-47)	838
14	State income taxes	Exhibit No.: A-13 (HLR-46)	25,256
15	Federal income taxes	Exhibit No.: A-13 (HLR-45)	83,757
16	Total operating expenses	Sum of Lines 5 through 15	1,768,943
17	Net operating income	Line 4 - Line 16	544,194
18	AFUDC	Exhibit No.: A-13 (HLR-48)	1,298
19	Net operating income, including AFUDC	Line 17 + Line 18	545,492
	Net Operating Income Adjustments		
20	Income tax effect of interest {a}	---------- Included in Lines 13, 14, and 15 ----------	
21	Interest synchronization adjustment {a}	---------- Included in Lines 13, 14, and 15 ----------	
22	Total adjusted net operating income	Line 19	545,492

Notes

{a} Income tax effect of interest and the interest synchronization adjustment are included in the calculation of local, state, and federal income tax. The separate calculations can be found on Exhibit No.: A-13 (HLR-49) and Exhibit No.: A-13 (HLR-50)

Schedule: C-1.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of Adjusted Net Operating Income
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-13 (HLR-37)
Schedule: C-1.1
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No.	(a) Description	(b) Source	(c) Sales Revenues	(d) Transporation Revenues	(e) Other Revenues	(f) COGS	(g) LAUF	(h) Company Use Gas	(i) Other O&M	(j) Depreciation	(k) Amortization	(l) Property Taxes	(m) General Taxes	(n) CIT	(o) SIT	(p) FIT	(q) NOI	(r) AFUDC	(s) Adjusted NOI
1	Net operating income - historical year	Exhibit No.: A-3 (HLR-9)	2,178,973	115,122	105,825	875,604	21,116	(820)	423,918	337,042	8,946	156,077	18,829	778	17,273	73,864	467,293	5,808	473,101
	Historical Adjustments																		
2	Sales revenue weather adjustment	Exh. A-15 (MA-14), Col.(d), Line 5	106,805	-	-	-	-	-	-	-	-	-	-	171	5,597	21,218	79,820	-	79,820
3	Transportation revenue weather adjustment	Exh. A-15 (MA-14), Col.(d), Line 8	-	4,853	-	-	-	-	-	-	-	-	-	8	254	964	3,627	-	3,627
4	EWR surcharge revenues	WP-HLR-9	(90,336)	-	-	-	-	-	-	-	-	-	-	(145)	(4,734)	(17,946)	(67,512)	-	(67,512)
5	Jobwork revenues	WP-HLR-10	-	-	304	-	-	-	-	-	-	-	-	0	16	60	227	-	227
6	Interest income on cash operating accounts	WP-HLR-11	-	-	473	-	-	-	-	-	-	-	-	1	25	94	353	-	353
7	Other revenues adjustments	WP-HLR-32, Lines 40 through 42	-	-	(6,475)	-	-	-	-	-	-	-	-	(10)	(339)	(1,286)	(4,839)	-	(4,839)
8	EWR surcharge expenses	WP-HLR-9	-	-	-	-	-	-	(90,336)	-	-	-	-	145	4,734	17,946	67,512	-	67,512
9	Jobwork expenses	WP-HLR-10	-	-	-	-	-	-	61	-	-	-	-	(0)	(3)	(12)	(45)	-	(45)
10	Compensation expenses	WP-HLR-12	-	-	-	-	-	-	(110)	-	-	-	-	0	6	22	82	-	82
11	Advertising expenses	WP-HLR-13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Dues, donations, & lobbying expenses	WP-HLR-14	-	-	-	-	-	-	(331)	-	-	-	-	1	17	66	247	-	247
13	Interest expense on security deposits	WP-HLR-15	-	-	-	-	-	-	237	-	-	-	-	(0)	(12)	(47)	(177)	-	(177)
14	Voluntary Separation Program (VSP) expenses	WP-HLR-16	-	-	-	-	-	-	(12,582)	-	-	-	(718)	21	697	2,642	9,939	-	9,939
15	Income tax effect of interest	Exhibit No.: A-3 (HLR-21)	-	-	-	-	-	-	-	-	-	-	-	5	176	668	(850)	-	(850)
16	Interest synchronization adjustment	Exhibit No.: A-3 (HLR-22)	-	-	-	-	-	-	-	-	-	-	-	(2)	(50)	(188)	239	-	239
17	Adjusted net operating income - historical year	Sum of Lines 1 through 16	2,195,442	119,975	100,126	875,604	21,116	(820)	320,857	337,042	8,946	156,077	18,111	973	23,657	98,065	555,916	5,808	561,724
	Test Year Adjustments																		
18	Sales revenues		(13,368)	-	-	-	-	-	-	-	-	-	-	(21)	(700)	(2,656)	(9,990)	-	(9,990)
19	Transportation revenues		-	(17,579)	-	-	-	-	-	-	-	-	-	(28)	(921)	(3,492)	(13,137)	-	(13,137)
20	Other revenues		-	-	(71,459)	-	-	-	-	-	-	-	-	(114)	(3,744)	(14,196)	(53,404)	-	(53,404)
21	Cost of gas sold		-	-	-	(138,016)	-	-	-	-	-	-	-	221	7,232	27,418	103,145	-	103,145
22	LAUF		-	-	-		(8,407)	-	-	-	-	-	-	13	441	1,670	6,283	-	6,283
23	Company use gas		-	-	-	-	-	6,322	-	-	-	-	-	(10)	(331)	(1,256)	(4,725)	-	(4,725)
24	Other operation and maintenance		-	-	-	-	-	-	(22,953)	-	-	-	-	37	1,203	4,560	17,153	-	17,153
25	Depreciation		-	-	-	-	-	-	-	37,123	-	-	-	(59)	(1,945)	(7,375)	(27,743)	-	(27,743)
26	Amortization		-	-	-	-	-	-	-	-	1,293	-	-	(2)	(68)	(257)	(967)	-	(967)
27	Property taxes		-	-	-	-	-	-	-	-	-	45,123	-	(72)	(2,364)	(8,964)	(33,722)	-	(33,722)
28	Other general taxes		-	-	-	-	-	-	-	-	-	-	1,674	(3)	(88)	(333)	(1,251)	-	(1,251)
29	Other (local) income taxes		-	-	-	-	-	-	-	-	-	-	-	(96)	-	20	76	-	76
30	State income taxes		-	-	-	-	-	-	-	-	-	-	-	-	2,886	(606)	(2,280)	-	(2,280)
31	Federal income taxes		-	-	-	-	-	-	-	-	-	-	-	-	-	(8,842)	8,842	-	8,842
32	AFUDC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(4,510)	(4,510)
33	Adjusted net operating income - projected test year	Exhibit No.: A-13 (HLR-36)	2,182,075	102,396	28,666	737,588	12,709	5,502	297,904	374,164	10,239	201,200	19,785	838	25,256	83,757	544,194	1,298	545,492

Schedule: C-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of the Revenue Conversion Factor
For the Projected 12-Month Period Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-13 (HLR-38)
Schedule: C-2
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Income base - before taxes		100.0000
2	State income tax	Line 1 * 5.24% State Income Tax Rate	5.2400
3	Other (local) income tax	Line 1 * 0.16% Other {Local) Income Tax Rate	0.1600
4	Federal income tax base	Line 1 - Line 2 - Line 3	94.6000
5	Federal income tax	Line 4 * 21.00% Federal Income Tax Rate	19.8660
6	Income base - after taxes	Line 4 - Line 5	74.7340
7	Revenue conversion factor	Line 1 / Line 6	1.3381

Schedule: C-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Operating Revenues
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-13 (HLR-39)
Schedule: C-3
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Sales revenues	Exhibit No.: A-15 (MA-14) Col.(h), Line 5	2,182,075
2	Transportation revenues	Exhibit No.: A-15 (MA-14) Col.(h), Line 8	102,396
3	Other revenues	WP-HLR-32	28,666
4	Total operating revenues	Sum of Lines 1 through 3	2,313,137

Schedule: C-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Gas Sold
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-13 (HLR-40)
Schedule: C-4
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Total cost of gas sold	Exhibit No.: A-15 (MA-14) Col.(f), Line 11	737,588

Schedule: C-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Operation and Maintenance Expenses
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-13 (HLR-41)
Schedule: C-5
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Historical Year	(d) Change	(e) Projected Year
1	LAUF	Exhibit No.: A-73 (TKJ-2)	21,116	(8,407)	12,709
2	Company use gas	Exhibit No.: A-73 (TKJ-2)	(820)	6,322	5,502
3	Compression and storage	Exhibit No.: A-72 (TKJ-1)	17,880	(303)	17,577
4	Gas operations	Exhibit No.: A-86 (JPP-1)	111,299	22,336	133,635
5	Pipeline integrity	Exhibit No.: A-58 (MPG-1)	17,900	649	18,549
6	Transmission	Exhibit No.: A-58 (MPG-1)	2,134	2,446	4,580
7	Gas engineering and supply	Exhibit No.: A-81 (KAP-2)	16,015	6,180	22,195
8	Customer experience and operations	Exhibit No.: A-37 (JRB-2)	36,689	(4,843)	31,846
9	Operations support	Exhibit No.: A-68 (QAG-2)	9,639	(113)	9,525
10	Information technology and security - operations	Exhibit No.: A-17 (SHB-1)	28,338	8,420	36,758
11	Information technology and security - investments	Exhibit No.: A-19 (SHB-3)	4,912	13,036	17,948
12	Pension plans A/B	Exhibit No.: A-64 (KKG-1)	(28,482)	(6,319)	(34,801)
13	Defined company contribution plan	Exhibit No.: A-64 (KKG-1)	7,952	203	8,155
14	401(k) employees' savings plan	Exhibit No.: A-64 (KKG-1)	6,449	166	6,615
15	Active healthcare/ insurance/ LTD	Exhibit No.: A-64 (KKG-1)	18,359	1,406	19,765
16	Retiree healthcare and life insurance	Exhibit No.: A-64 (KKG-1)	(33,761)	(8,941)	(42,702)
17	Other benefits	Exhibit No.: A-64 (KKG-1)	2,493	725	3,218
18	Pension volatility mechanism deferral	Exhibit No.: A-64 (KKG-1)	(266)	266	-
19	OPEB volatility mechanism deferral	Exhibit No.: A-64 (KKG-1)	655	(655)	-
20	Pension volatility mechanism amortization	Exhibit No.: A-64 (KKG-1)	-	(791)	(791)
21	OPEB volatility mechanism amortization	Exhibit No.: A-64 (KKG-1)	-	(1,423)	(1,423)
22	Incentive compensation	Exhibit No.: A-41 (AMC-3)	1,974	(428)	1,546
23	Uncollectibles expense	Exhibit No.: A-43 (MJF-1)	17,234	(1,907)	15,327
24	Injuries and damages	Exhibit No.: A-43 (MJF-1)	1,467	812	2,279
25	MGP direct projected management costs	Exhibit No.: A-43 (MJF-1)	949	(18)	930
26	Corporate services	Exhibit No.: A-44 (MJF-2)	27,105	(231)	26,874
27	Jobwork expenses	WP-HLR-10	61	-	61
28	ASP expenses	WP-HLR-10	52,866	(52,866)	-
29	Interest expense on security deposits	WP-HLR-15	237	-	237
30	Demand response amortization	Exhibit No.: A-3 (HLR-14)	853	(853)	-
31	Total operation and maintenance expenses	Sum of Lines 1 through 30	341,246	(25,131)	316,115
32	Less: LAUF	Line 1	21,116	(8,407)	12,709
33	Less: Company Use Gas	Line 2	(820)	6,322	5,502
34	Total other operation and maintenance expenses	Line 31 - Line 32 - Line 33	320,950	(23,046)	297,904

Schedule: C-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Inflation and Merit Increases Included in Operation and Maintenance Expenses
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-13 (HLR-42)
Schedule: C-5.1
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No.	(a) Description	(b) Source	(c) Historical O&M for the 12 Months Ended 12/31/2023	Projected Adjustments (d) Inflation & Merit for the 12 Months Ended 12/31/2024	(e) Inflation & Merit for the 12 Months Ended 12/31/2025	(f) Inflation & Merit for the 10 Months Ended 10/31/2026	(g) Other Adjustments	(h) Total Projected Adjustments ∑ (d) thru (g)	(i) Projected O&M for the 12 Months Ended 10/31/2026 (c) + (h)
1	LAUF	Exhibit No.: A-73 (TKJ-2)	21,116	-	-	-	(8,407)	(8,407)	12,709
2	Company use gas	Exhibit No.: A-73 (TKJ-2)	(820)	-	-	-	6,322	6,322	5,502
3	Compression and storage	Exhibit No.: A-72 (TKJ-1)	17,880	-	-	-	(303)	(303)	17,577
4	Gas operations	Exhibit No.: A-86 (JPP-1)	111,299	-	-	-	22,336	22,336	133,635
5	Pipeline integrity	Exhibit No.: A-58 (MPG-1)	17,900	-	-	-	649	649	18,549
6	Transmission	Exhibit No.: A-58 (MPG-1)	2,134	-	-	-	2,446	2,446	4,580
7	Gas engineering and supply	Exhibit No.: A-81 (KAP-2)	16,015	-	-	-	6,180	6,180	22,195
8	Customer experience and operations	Exhibit No.: A-37 (JRB-2)	36,689	1,174	909	808	(7,734)	(4,843)	31,846
9	Operations support	Exhibit No.: A-68 (QAG-2)	9,639	-	-	-	(113)	(113)	9,525
10	Information technology and security - operations	Exhibit No.: A-17 (SHB-1)	28,338	252	198	176	7,794	8,420	36,758
11	Information technology and security - investments	Exhibit No.: A-19 (SHB-3)	4,912	-	-	-	13,036	13,036	17,948
12	Pension plans A/B	Exhibit No.: A-64 (KKG-1)	(28,482)	(911)	(705)	(627)	(4,075)	(6,319)	(34,801)
13	Defined company contribution plan	Exhibit No.: A-64 (KKG-1)	7,952	254	197	175	(423)	203	8,155
14	401(k) employees' savings plan	Exhibit No.: A-64 (KKG-1)	6,449	206	160	142	(342)	166	6,615
15	Active healthcare/ insurance/ LTD	Exhibit No.: A-64 (KKG-1)	18,359	587	455	404	(40)	1,406	19,765
16	Retiree healthcare and life insurance	Exhibit No.: A-64 (KKG-1)	(33,761)	(1,080)	(836)	(743)	(6,281)	(8,941)	(42,702)
17	Other benefits	Exhibit No.: A-64 (KKG-1)	2,493	80	62	55	529	725	3,218
18	Pension volatility mechanism deferral	Exhibit No.: A-64 (KKG-1)	(266)	(9)	(7)	(6)	287	266	-
19	OPEB volatility mechanism deferral	Exhibit No.: A-64 (KKG-1)	655	21	16	14	(707)	(655)	-
20	Pension volatility mechanism amortization	Exhibit No.: A-64 (KKG-1)	-	-	-	-	(791)	(791)	(791)
21	OPEB volatility mechanism amortization	Exhibit No.: A-64 (KKG-1)	-	-	-	-	(1,423)	(1,423)	(1,423)
22	Incentive compensation	Exhibit No.: A-41 (AMC-3)	1,974	52	36	32	(547)	(428)	1,546
23	Uncollectibles expense	Exhibit No.: A-43 (MJF-1)	17,234	-	-	-	(1,907)	(1,907)	15,327
24	Injuries and damages	Exhibit No.: A-43 (MJF-1)	1,467	-	-	-	812	812	2,279
25	MGP direct projected management costs	Exhibit No.: A-43 (MJF-1)	949	-	-	-	(18)	(18)	930
26	Corporate services	Exhibit No.: A-44 (MJF-2)	27,105	867	671	597	(2,366)	(231)	26,874
27	Jobwork expenses	WP-HLR-10	61	-	-	-	-	-	61
28	ASP expenses	WP-HLR-10	52,866	-	-	-	(52,866)	(52,866)	-
29	Interest expense on security deposits	WP-HLR-15	237	-	-	-	-	-	237
30	Demand response amortization	Exhibit No.: A-3 (HLR-14)	853	-	-	-	(853)	(853)	-
31	Total operation and maintenance expenses	Sum of Lines 1 through 30	341,246	1,494	1,155	1,027	(28,806)	(25,131)	316,115
32	Less: LAUF	Line 1	21,116	-	-	-	(8,407)	(8,407)	12,709
33	Less: Company use gas	Line 2	(820)	-	-	-	6,322	6,322	5,502
34	Net operation and maintenance expenses	Line 31 - Line 32 - Line 33	320,950	1,494	1,155	1,027	(26,721)	(23,046)	297,904

Schedule: C-6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Depreciation and Amortization Expenses
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-13 (HLR-43)
Schedule: C-6
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Distribution	WP-HLR-20, Col. (d), Line 57	218,868
2	Transmission	WP-HLR-20, Col. (d), Line 58	76,856
3	Transmission Other	WP-HLR-20, Col. (d), Line 59	-
4	UGS Amortization	WP-HLR-20, Col. (d), Line 60	113
5	UGS Depreciation	WP-HLR-20, Col. (d), Line 61	39,239
6	UGS Non-Current	WP-HLR-20, Col. (d), Line 62	-
7	G-Intangibles	WP-HLR-20, Col. (d), Line 63	2,322
8	C-Intangibles	WP-HLR-20, Col. (d), Line 64	9,565
9	NGP	WP-HLR-20, Col. (d), Line 65	-
10	G-GP Structures	WP-HLR-20, Col. (d), Line 66	2,759
11	G-GP Computers	WP-HLR-20, Col. (d), Line 67	1,359
12	G-GP Transportation	WP-HLR-20, Col. (d), Line 68	-
13	G-GP Other	WP-HLR-20, Col. (d), Line 69	3,710
14	C-GP Structures	WP-HLR-20, Col. (d), Line 70	9,018
15	C-GP Computers	WP-HLR-20, Col. (d), Line 71	5,703
16	C-GP Transportation	WP-HLR-20, Col. (d), Line 72	-
17	C-GP Other	WP-HLR-20, Col. (d), Line 73	4,652
18	Total depreciation expenses	Sum of Lines 1 through 17	374,164
19	MGP amortization	Exhibit No.: A-47 (MJF-5), p.1, Line 23, Col. (y)	7,280
20	Riverside Storage Field regulatory asset amortization	WP-HLR-34	2,959
21	Total amortization expenses	Line 19 + Line 20	10,239
22	Total depreciation and amortization expenses	Line 18 + Line 21	384,404

Schedule: C-7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
General Taxes
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-13 (HLR-44)
Schedule: C-7
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Real and personal property taxes	Exhibit No.: A-99 (BJV-1), Line 10	201,200
	Projected payroll taxes		
2	Total payroll taxes - historical year	Exhibit No.: A-3 (HLR-16)	13,540
3	Inflation factor 2024	WP-HLR-33	103.20%
4	Inflation factor 2025	WP-HLR-33	102.40%
5	Inflation factor 2026	WP-HLR-33	102.50%
6	Total payroll taxes - projected year	Line 2 * Line 3 * Line 4 * Line 5	14,666
	Projected other general taxes		
7	State MPSC assessment	P-521, p.262.1, Col.(j), Lines 36 - 37	4,694
8	Total operating revenues - historical year	Exhibit No.: A-3 (HLR-9)	2,399,920
9	Average State MPSC assessment rate	Line 7 / Line 8	0.20%
10	Total operating revenues - projected year	Exhibit No.: A-13 (HLR-36)	2,313,137
11	Average State MPSC assessment rate	Line 9	0.20%
12	Projected State MPSC assessment	Line 10 * Line 11	4,524
13	Incremental change in State MPSC assessment	Line 12 - Line 7	(170)
14	Other general taxes - historical year	Exhibit No.: A-3 (HLR-16)	5,288
15	Total other general taxes - projected year	Line 13 + Line 14	5,119
16	Total general taxes	Line 1 + Line 6 + Line 15	220,985

Schedule: C-8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Federal Income Taxes
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-13 (HLR-45)
Schedule: C-8
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Operating revenues	Exhibit No.: A-13 (HLR-39)	2,313,137
2	Cost of gas sold	Exhibit No.: A-13 (HLR-40)	(737,588)
3	LAUF and company use gas	Exhibit No.: A-13 (HLR-41)	(18,211)
4	Other O&M expenses	Exhibit No.: A-13 (HLR-41)	(297,904)
5	Depreciation and amortization expenses	Exhibit No.: A-13 (HLR-43)	(384,404)
6	General taxes	Exhibit No.: A-13 (HLR-44)	(220,985)
7	State income taxes	Exhibit No.: A-13 (HLR-46), Line 22 * -1	(25,256)
8	Other (local) income taxes	Exhibit No.: A-13 (HLR-47), Line 19 * -1	(838)
9	Net operating income	Sum of Lines 1 through 8	627,952
10	Allowable interest expense	Exhibit No.: A-13 (HLR-49)	(214,171)
11	Allowable JDITC interest expense	Exhibit No.: A-13 (HLR-50)	(937)
12	Pre-tax operating income	Sum of Lines 9 through 11	412,843
	Permanent Differences		
13	Meals and entertainment	Tax Department	461
14	Non-deductible parking	Tax Department	59
15	Total permanent differences	Line 13 + Line 14	520
	Temporary Differences		
16	Book depreciation	Exhibit No.: A-13 (HLR-43), Line 18	374,164
17	Tax depreciation	Tax Department	(640,746)
18	263A - mixed service costs deduction	Tax Department	(20,558)
19	Contributions in aid of construction	Tax Department	18,356
20	Cost of removal	Tax Department	(63,981)
21	Gain/loss on ACRS/MACRS dispositions	Tax Department	(11,061)
22	Software expense	Tax Department	-
23	Tax interest during construction	Tax Department	13,107
24	Bad debt allowance	Tax Department	-
25	Gas cost recovery	Tax Department	-
26	Gas inventory adjustment	Tax Department	(8,483)
27	MGP reg liability	Exhibit No.: A-13 (HLR-43), Line 19	7,280
28	OPEB - book expense	Exhibit No.: A-13 (HLR-41), Line 16	(42,702)
29	OPEB - payments	Tax Department	(3,600)
30	Pension book expense	Exhibit No.: A-13 (HLR-41), Line 12	(34,801)
31	Pension - payments	Tax Department	-
32	Premium, discount & debt expense amortization	Tax Department	1,600
33	Real and personal property taxes	Tax Department	(30,416)
34	Regulatory liability - revenue reserves	Tax Department	1,840
35	Deferred state income taxes	Exhibit No.: A-13 (HLR-46), Line 21	27,995
36	Deferred city income taxes	Exhibit No.: A-13 (HLR-47), Line 18	834
37	Total temporary differences	Sum of Lines 16 through 36	(411,171)
38	Federal taxable income	Line 12 + Line 15 + Line 37	2,192
	Calculation of Current Federal Income Tax Expenses		
39	Current federal income taxes	Line 38 * 21.00% Federal Income Tax Rate	460
40	Research & development credit	Tax Department	(360)
41	Total current federal income tax exenses	Line 39 + Line 40	100
	Calculation of Deferred Federal Income Tax Expenses		
42	Deferred federal income taxes	(Line 37 * 21.00% Federal Income Tax Rate) * -1	86,346
43	TCJA Tracker - U-20309	Tax Department	2,540
44	FAS 109	Tax Department	(229)
45	Investment tax credit amortization	Tax Department	(418)
46	Repealed Medicare subsidy benefit	Tax Department	-
47	TCJA amortization - ARAM	Tax Department	(7,635)
48	TCJA amortization - non-ARAM	Tax Department	3,053
49	Total deferred federal income tax expenses	Sum of Lines 42 through 48	83,657
50	Total federal income taxes	Line 41 + Line 49	83,757

Schedule: C-9

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
State Income Taxes
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-13 (HLR-46)
Schedule: C-9
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Operating revenues	Exhibit No.: A-13 (HLR-39)	2,313,137
2	Cost of gas sold	Exhibit No.: A-13 (HLR-40)	(737,588)
3	LAUF and company use gas	Exhibit No.: A-13 (HLR-41)	(18,211)
4	Other O&M expenses	Exhibit No.: A-13 (HLR-41)	(297,904)
5	Depreciation and amortization expenses	Exhibit No.: A-13 (HLR-43)	(384,404)
6	General taxes	Exhibit No.: A-13 (HLR-44)	(220,985)
7	Net operating income	Sum of Lines 1 through 6	654,045
8	Allowable interest expense	Exhibit No.: A-13 (HLR-49)	(214,171)
9	Allowable JDITC interest expense	Exhibit No.: A-13 (HLR-50)	(937)
10	Pre-tax operating income	Sum of Lines 7 through 9	438,937
11	Total permanent differences	Exhibit No.: A-13 (HLR-45), Line 15	520
12	Schedule M temp diff, excluding DSIT and DCIT	Exhibit No.: A-13 (HLR-45), Lines 16 - 34	(440,001)
13	Depreciation/gain-loss adjustment	Tax Department	(51,737)
14	State taxable income	Sum of Lines 10 through 13	(52,281)
15	Current state income taxes	Line 14 * 5.24% State Income Tax Rate	(2,740)
	Calculation of Deferred State Income Tax Expenses		
16	Deferred state income tax expenses, tax effected	((Lines 12 + 13) * 5.24% State Income Tax Rate) * -1	25,767
17	FAS 109	Tax Department	51
18	Repealed Medicare subsidy benefit - state	Tax Department	-
19	Deferred - amortization of regulatory asset per U-15986	Tax Department	-
20	Deferred - amortization of state income tax transition reg asset	Tax Department	2,177
21	Deferred state income taxes	Sum of Lines 16 through 20	27,995
22	Total state income taxes	Line 15 + Line 21	25,256

Schedule: C-10

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Other (or Local) Taxes
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-13 (HLR-47)
Schedule: C-10
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Operating revenues	Exhibit No.: A-13 (HLR-39)	2,313,137
2	Cost of gas sold	Exhibit No.: A-13 (HLR-40)	(737,588)
3	LAUF and company use gas	Exhibit No.: A-13 (HLR-41)	(18,211)
4	Other O&M expenses	Exhibit No.: A-13 (HLR-41)	(297,904)
5	Depreciation and amortization expenses	Exhibit No.: A-13 (HLR-43)	(384,404)
6	General taxes	Exhibit No.: A-13 (HLR-44)	(220,985)
7	State income taxes	Exhibit No.: A-13 (HLR-46)	(25,256)
8	Net operating income	Sum of Lines 1 through 7	628,789
9	Allowable interest expense	Exhibit No.: A-13 (HLR-49)	(214,171)
10	Allowable JDITC interest expense	Exhibit No.: A-13 (HLR-50)	(937)
11	Pre-tax operating income	Sum of Lines 8 through 10	413,681
12	Total permanent differences	Exhibit No.: A-13 (HLR-45), Line 15	520
13	Schedule M temp diff, excluding DCIT	Exhibit No.: A-13 (HLR-45), Lines 16 - 35	(412,006)
14	Other (local) taxable income	Sum of Lines 11 through 13	2,195
15	Current other (local) income taxes	Line 14 * 0.16% Other (Local) Income Tax Rate	4
	Calculation of Deferred Other (Local) Income Tax Expenses		
16	Deferred other (local) income tax expenses, tax effected	(Line 13 * 0.16% Other (Local) Income Tax Rate) * -1	659
17	Deferred - amortization of reg asset	Tax Department	175
18	Total deferred other (local) income taxes	Line 16 + Line 17	834
19	Total other (local) income taxes	Line 15 + Line 18	838

Schedule: C-11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Allowance for Funds Used During Construction
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-13 (HLR-48)
Schedule: C-11
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Total allowance for funds used during construction	WP-HLR-21	1,298

Schedule: C-12

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Income Tax Effect of Interest
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-13 (HLR-49)
Schedule: C-12
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Rate base	Exhibit No.: A-12 (HLR-31)	11,750,740
2	Weighted cost of debt {1}	Exhibit No.: A-14 (MRB-1)	1.82%
3	Allowable interest expense	Line 1 * Line 2	214,171
4	Pro forma interest expense - historical year	Exhibit No.: A-3 (HLR-21)	158,965
5	Increase/ (decrease) in allowable interest deduction	Line 3 - Line 4	55,206
6	Impact on taxable income	Line 5 * -1	(55,206)
7	Impact on local income taxes	Line 6 * 0.16% Local Income Tax Rate	(88)
8	Impact on state income taxes	Line 6 * 5.24% State Income Tax Rate	(2,893)
9	Impact on federal taxable income	Line 6 - Line 7 - Line 8	(52,225)
10	Impact on federal income taxes	Line 9 * 21.00% Federal Income Tax Rate	(10,967)
11	Total impact on net operating income	(Line 7 + Line 8 + Line 10) * -1	13,948

Notes

{1} Excludes JDITC

Schedule: C-13

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Interest Synchronization Adjustment
For the Projected 12-Month Period Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-13 (HLR-50)
Schedule: C-13
Page: 1 of 1
Witness: HLRayl
Date: December 2024

Line No	(a) Description	(b) Source	(c) Amount
1	Rate base	Exhibit No.: A-12 (HLR-31)	11,750,740
2	JDITC debt-related portion of the capital structure	Source: Exhibit No.: A-14 (MRB-1)	0.18%
3	Portion of rate base funded by JDITC	Line 1 * Line 2	21,532
4	Cost of JDITC - debt portion	Source: Exhibit No.: A-14 (MRB-1)	4.35%
5	Allowable JDITC interest expense	Line 3 * Line 4	937
6	Allowable JDITC interest expense - historical year	Exhibit No.: A-3 (HLR-22)	945
7	Increase/ (decrease) in allowable JDITC interest expense	Line 5 - Line 6	(8)
8	Impact on taxable income	Line 7 * -1	8
9	Impact on local income taxes	Line 7 * 0.16% Local Income Tax Rate	0
10	Impact on state income taxes	Line 8 * 5.24% State Income Tax Rate	0
11	Impact on federal taxable income	Line 8 - Line 9 - Line 10	8
12	Impact on federal income taxes	Line 11 * 21.00% Federal Income Tax Rate	2
13	Total impact on net operating income	(Line 9 + Line 10 + Line 12) * -1	(2)

COST OF EQUITY ANALYSES
SUMMARY OF RESULTS

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	8.59%	9.87%	11.30%
90-Day Avg. Stock Price	8.79%	10.06%	11.50%
180-Day Avg. Stock Price	8.95%	10.23%	11.66%
Average	8.78%	10.05%	11.49%
Median Results:			
30-Day Avg. Stock Price	8.48%	9.83%	11.33%
90-Day Avg. Stock Price	8.72%	10.05%	11.57%
180-Day Avg. Stock Price	8.86%	10.17%	11.71%
Average	8.69%	10.02%	11.54%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.05%	11.04%	11.07%
Current Bloomberg Beta	10.15%	10.13%	10.20%
Long-term Avg. *Value Line* Beta	10.08%	10.06%	10.13%
ECAPM:			
Current *Value Line* Beta	11.30%	11.29%	11.32%
Current Bloomberg Beta	10.62%	10.61%	10.66%
Long-term Avg. *Value Line* Beta	10.57%	10.56%	10.61%
Bond Yield Risk Premium	10.22%	10.19%	10.35%

PROXY GROUP SCREENING DATA AND RESULTS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
Company	Ticker	Dividends	S&P Credit Rating Between BBB- and AAA	Covered by More Than 1 Analyst	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	% Regulated Operating Income > 70%	% Regulated Natural Gas Operating Income > 60%	Announced Merger
Atmos Energy Corporation	ATO	Yes	A-	Yes	Yes	100.00%	66.30%	No
NiSource Inc.	NI	Yes	BBB+	Yes	Yes	99.89%	67.83%	No
Northwest Natural Gas Company	NWN	Yes	A	Yes	Yes	100.00%	90.55%	No
ONE Gas, Inc.	OGS	Yes	A-	Yes	Yes	100.00%	100.00%	No
Southwest Gas Corporation	SWX	Yes	BBB-	Yes	Yes	86.75%	90.89%	No
Spire, Inc.	SR	Yes	BBB+	Yes	Yes	83.38%	100.00%	No

Notes:
[1] Bloomberg Professional
[2] Bloomberg Professional
[3] Yahoo! Finance and Zacks
[4] Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] Form 10-K's for 2023, 2022, and 2021
[6] Form 10-K's for 2023, 2022, and 2021
[7] S&P Capital IQ Pro Financial News Releases

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.22	$133.50	2.41%	2.50%	7.00%	7.40%	7.00%	7.13%	9.50%	9.63%	9.90%
NiSource Inc.	NI	$1.06	$33.46	3.17%	3.30%	9.50%	7.70%	7.00%	8.07%	10.28%	11.36%	12.82%
Northwest Natural Gas Company	NWN	$1.95	$39.87	4.89%	5.00%	6.50%	2.80%	n/a	4.65%	7.76%	9.65%	11.55%
ONE Gas, Inc.	OGS	$2.64	$70.80	3.73%	3.81%	3.50%	5.00%	5.00%	4.50%	7.29%	8.31%	8.82%
Southwest Gas Corporation	SWX	$2.48	$72.18	3.44%	3.55%	10.00%	4.00%	6.00%	6.67%	7.50%	10.22%	13.61%
Spire, Inc.	SR	$3.02	$65.59	4.60%	4.73%	4.50%	6.36%	5.00%	5.29%	9.21%	10.01%	11.11%
Mean		$2.40	$69.23	3.71%	3.81%	6.83%	5.54%	6.00%	6.05%	8.59%	9.87%	11.30%
Median		$2.56	$68.20	3.58%	3.68%	6.75%	5.68%	6.00%	5.98%	8.48%	9.83%	11.33%

Notes:
[1] Bloomberg Professional as of September 30, 2024
[2] Bloomberg Professional 30-day average as of September 30, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	3.22	$124.16	2.59%	2.69%	7.00%	7.40%	7.00%	7.13%	9.68%	9.82%	10.09%
NiSource Inc.	NI	1.06	$30.78	3.44%	3.58%	9.50%	7.70%	7.00%	8.07%	10.56%	11.65%	13.11%
Northwest Natural Gas Company	NWN	1.95	$37.96	5.14%	5.26%	6.50%	2.80%	n/a	4.65%	8.01%	9.91%	11.80%
ONE Gas, Inc.	OGS	2.64	$66.14	3.99%	4.08%	3.50%	5.00%	5.00%	4.50%	7.56%	8.58%	9.09%
Southwest Gas Corporation	SWX	2.48	$72.50	3.42%	3.53%	10.00%	4.00%	6.00%	6.67%	7.49%	10.20%	13.59%
Spire, Inc.	SR	3.02	$62.70	4.82%	4.94%	4.50%	6.36%	5.00%	5.29%	9.42%	10.23%	11.33%
Mean		$2.40	$65.71	3.90%	4.01%	6.83%	5.54%	6.00%	6.05%	8.79%	10.06%	11.50%
Median		$2.56	$64.42	3.72%	3.83%	6.75%	5.68%	6.00%	5.98%	8.72%	10.05%	11.57%

Notes:
[1] Bloomberg Professional as of September 30, 2024
[2] Bloomberg Professional 90-day average as of September 30, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.22	$118.94	2.71%	2.80%	7.00%	7.40%	7.00%	7.13%	9.80%	9.94%	10.21%
NiSource Inc.	NI	$1.06	$28.63	3.70%	3.85%	9.50%	7.70%	7.00%	8.07%	10.83%	11.92%	13.38%
Northwest Natural Gas Company	NWN	$1.95	$37.19	5.24%	5.36%	6.50%	2.80%	n/a	4.65%	8.12%	10.01%	11.91%
ONE Gas, Inc.	OGS	$2.64	$63.46	4.16%	4.25%	3.50%	5.00%	5.00%	4.50%	7.73%	8.75%	9.26%
Southwest Gas Corporation	SWX	$2.48	$70.20	3.53%	3.65%	10.00%	4.00%	6.00%	6.67%	7.60%	10.32%	13.71%
Spire, Inc.	SR	$3.02	$60.50	4.99%	5.12%	4.50%	6.36%	5.00%	5.29%	9.60%	10.41%	11.51%
Mean		$2.40	$63.15	4.06%	4.17%	6.83%	5.54%	6.00%	6.05%	8.95%	10.23%	11.66%
Median		$2.56	$61.98	3.93%	4.05%	6.75%	5.68%	6.00%	5.98%	8.86%	10.17%	11.71%

Notes:
[1] Bloomberg Professional as of September 30, 2024
[2] Bloomberg Professional 180-day average as of September 30, 2024
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta	[3] Market Return	[4] Market Risk Premium	[5] Cost of Equity: CAPM	[6] Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.07%	0.85	12.04%	7.97%	10.85%	11.15%
NiSource Inc.	NI	4.07%	0.95	12.04%	7.97%	11.64%	11.74%
Northwest Natural Gas Company	NWN	4.07%	0.85	12.04%	7.97%	10.85%	11.15%
ONE Gas, Inc.	OGS	4.07%	0.85	12.04%	7.97%	10.85%	11.15%
Southwest Gas Corporation	SWX	4.07%	0.90	12.04%	7.97%	11.25%	11.44%
Spire, Inc.	SR	4.07%	0.85	12.04%	7.97%	10.85%	11.15%
Mean						11.05%	11.30%
Median						10.85%	11.15%

Notes:
[1] Bloomberg Professional 30-day average as of September 30, 2024
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2025 - Q1 2026)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.02%	0.85	12.04%	8.02%	10.84%	11.14%
NiSource Inc.	NI	4.02%	0.95	12.04%	8.02%	11.64%	11.74%
Northwest Natural Gas Company	NWN	4.02%	0.85	12.04%	8.02%	10.84%	11.14%
ONE Gas, Inc.	OGS	4.02%	0.85	12.04%	8.02%	10.84%	11.14%
Southwest Gas Corporation	SWX	4.02%	0.90	12.04%	8.02%	11.24%	11.44%
Spire, Inc.	SR	4.02%	0.85	12.04%	8.02%	10.84%	11.14%
Mean						11.04%	11.29%
Median						10.84%	11.14%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 10, October 1, 2024, at 2
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.30%	0.85	12.04%	7.74%	10.88%	11.17%
NiSource Inc.	NI	4.30%	0.95	12.04%	7.74%	11.66%	11.75%
Northwest Natural Gas Company	NWN	4.30%	0.85	12.04%	7.74%	10.88%	11.17%
ONE Gas, Inc.	OGS	4.30%	0.85	12.04%	7.74%	10.88%	11.17%
Southwest Gas Corporation	SWX	4.30%	0.90	12.04%	7.74%	11.27%	11.46%
Spire, Inc.	SR	4.30%	0.85	12.04%	7.74%	10.88%	11.17%
Mean						11.07%	11.32%
Median						10.88%	11.17%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 14
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta	[3] Market Return	[4] Market Risk Premium	[5] Cost of Equity: CAPM	[6] Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.07%	0.74	12.04%	7.97%	9.98%	10.50%
NiSource Inc.	NI	4.07%	0.79	12.04%	7.97%	10.38%	10.79%
Northwest Natural Gas Company	NWN	4.07%	0.69	12.04%	7.97%	9.60%	10.21%
ONE Gas, Inc.	OGS	4.07%	0.76	12.04%	7.97%	10.16%	10.63%
Southwest Gas Corporation	SWX	4.07%	0.82	12.04%	7.97%	10.63%	10.98%
Spire, Inc.	SR	4.07%	0.76	12.04%	7.97%	10.12%	10.60%
Mean						10.15%	10.62%
Median						10.14%	10.62%

Notes:
[1] Bloomberg Professional 30-day average as of September 30, 2024
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta\,(Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2025 - Q1 2026)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.02%	0.74	12.04%	8.02%	9.97%	10.49%
NiSource Inc.	NI	4.02%	0.79	12.04%	8.02%	10.37%	10.78%
Northwest Natural Gas Company	NWN	4.02%	0.69	12.04%	8.02%	9.58%	10.20%
ONE Gas, Inc.	OGS	4.02%	0.76	12.04%	8.02%	10.15%	10.62%
Southwest Gas Corporation	SWX	4.02%	0.82	12.04%	8.02%	10.62%	10.98%
Spire, Inc.	SR	4.02%	0.76	12.04%	8.02%	10.11%	10.59%
Mean						10.13%	10.61%
Median						10.13%	10.61%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 10, October 1, 2024, at 2
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.30%	0.74	12.04%	7.74%	10.04%	10.54%
NiSource Inc.	NI	4.30%	0.79	12.04%	7.74%	10.42%	10.83%
Northwest Natural Gas Company	NWN	4.30%	0.69	12.04%	7.74%	9.67%	10.26%
ONE Gas, Inc.	OGS	4.30%	0.76	12.04%	7.74%	10.22%	10.67%
Southwest Gas Corporation	SWX	4.30%	0.82	12.04%	7.74%	10.67%	11.02%
Spire, Inc.	SR	4.30%	0.76	12.04%	7.74%	10.18%	10.64%
Mean						10.20%	10.66%
Median						10.20%	10.66%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 14
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.07%	0.75	12.04%	7.97%	10.05%	10.55%
NiSource Inc.	NI	4.07%	0.76	12.04%	7.97%	10.09%	10.58%
Northwest Natural Gas Company	NWN	4.07%	0.71	12.04%	7.97%	9.72%	10.30%
ONE Gas, Inc.	OGS	4.07%	0.74	12.04%	7.97%	9.95%	10.47%
Southwest Gas Corporation	SWX	4.07%	0.83	12.04%	7.97%	10.67%	11.01%
Spire, Inc.	SR	4.07%	0.74	12.04%	7.97%	9.98%	10.49%
Mean						10.08%	10.57%
Median						10.01%	10.52%

Notes:
[1] Bloomberg Professional 30-day average as of September 30, 2024
[2] Source: LT Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q1 2025 - Q1 2026)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.02%	0.75	12.04%	8.02%	10.04%	10.54%
NiSource Inc.	NI	4.02%	0.76	12.04%	8.02%	10.08%	10.57%
Northwest Natural Gas Company	NWN	4.02%	0.71	12.04%	8.02%	9.71%	10.29%
ONE Gas, Inc.	OGS	4.02%	0.74	12.04%	8.02%	9.94%	10.46%
Southwest Gas Corporation	SWX	4.02%	0.83	12.04%	8.02%	10.66%	11.00%
Spire, Inc.	SR	4.02%	0.74	12.04%	8.02%	9.96%	10.48%
Mean						10.06%	10.56%
Median						10.00%	10.51%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 10, October 1, 2024, at 2
[2] Source: LT Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.30%	0.75	12.04%	7.74%	10.11%	10.59%
NiSource Inc.	NI	4.30%	0.76	12.04%	7.74%	10.15%	10.62%
Northwest Natural Gas Company	NWN	4.30%	0.71	12.04%	7.74%	9.79%	10.35%
ONE Gas, Inc.	OGS	4.30%	0.74	12.04%	7.74%	10.01%	10.52%
Southwest Gas Corporation	SWX	4.30%	0.83	12.04%	7.74%	10.71%	11.04%
Spire, Inc.	SR	4.30%	0.74	12.04%	7.74%	10.04%	10.54%
Mean						10.13%	10.61%
Median						10.07%	10.56%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 14
[2] Source: LT Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL BETA

Company	Ticker	[1] 12/31/2013	[2] 12/31/2014	[3] 12/31/2015	[4] 12/31/2016	[5] 12/31/2017	[6] 12/31/2018	[7] 12/31/2019	[8] 12/31/2020	[9] 12/31/2021	[10] 12/31/2022	[11] 12/31/2023	[12] Average
Atmos Energy Corporation	ATO	0.80	0.80	0.80	0.70	0.70	0.60	0.60	0.80	0.80	0.80	0.85	0.75
NiSource Inc.	NI	0.85	0.85	NMF	NMF	0.60	0.50	0.55	0.85	0.85	0.85	0.90	0.76
Northwest Natural Gas Company	NWN	0.65	0.70	0.65	0.65	0.70	0.60	0.60	0.80	0.85	0.80	0.80	0.71
ONE Gas, Inc.	OGS				0.70	0.70	0.65	0.65	0.80	0.80	0.80	0.80	0.74
Southwest Gas Corporation	SWX	0.80	0.85	0.80	0.75	0.80	0.70	0.70	0.95	0.95	0.90	0.90	0.83
Spire, Inc.	SR	0.65	0.70	0.70	0.70	0.70	0.65	0.65	0.85	0.85	0.85	0.85	0.74
Mean		0.75	0.78	0.74	0.70	0.70	0.62	0.63	0.84	0.85	0.83	0.85	0.75

Notes:
[1] Value Line, December 26, 2013
[2] Value Line, December 31, 2014
[3] Value Line, December 30, 2015
[4] Value Line, December 29, 2016
[5] Value Line, December 28, 2017
[6] Value Line, December 27, 2018
[7] Value Line, December 26, 2019
[8] Value Line, December 30, 2020
[9] Value Line, December 29, 2021
[10] Value Line, December 30, 2022
[11] Value Line, December 29, 2023
[11] Average ([1] - [11])

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.52%
[2] Estimate of the S&P 500 Growth Rate	10.45%
[3] S&P 500 Estimated Required Market Return	12.04%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	325.089	95.9	31,176.04		5.59%		-8.57%	
American Express Co	AXP	710.912	271.2	192,799.33	0.52%	1.03%	0.01%	15.62%	0.08%
Verizon Communications Inc	VZ	4209.52	44.91	189,049.54	0.51%	6.03%	0.03%	3.00%	0.02%
Broadcom Inc	AVGO	4670.576	172.5	805,674.36	2.17%	1.23%	0.03%	16.94%	0.37%
Boeing Co/The	BA	616.167	152.04	93,682.03				38.60%	
Solventum Corp	SOLV	172.711	69.72	12,041.41				-2.00%	
Caterpillar Inc	CAT	484.898	391.12	189,653.31	0.51%	1.44%	0.01%	8.38%	0.04%
JPMorgan Chase & Co	JPM	2845.165	210.86	599,931.49	1.62%	2.37%	0.04%	3.55%	0.06%
Chevron Corp	CVX	1828.917	147.27	269,344.61	0.73%	4.43%	0.03%	7.00%	0.05%
Coca-Cola Co/The	KO	4309.868	71.86	309,707.11	0.83%	2.70%	0.02%	6.36%	0.05%
AbbVie Inc	ABBV	1766.344	197.48	348,817.61	0.94%	3.14%	0.03%	8.80%	0.08%
Walt Disney Co/The	DIS	1813.587	96.19	174,448.93	0.47%	0.94%	0.00%	15.77%	0.07%
Corpay Inc	CPAY	69.433	312.76	21,715.87	0.06%			14.87%	0.01%
Extra Space Storage Inc	EXR	211.929	180.19	38,187.49		3.60%		-0.20%	
Exxon Mobil Corp	XOM	4442.827	117.22	520,788.18	1.40%	3.24%	0.05%	5.00%	0.07%
Phillips 66	PSX	418.569	131.45	55,020.90		3.50%		-9.00%	
General Electric Co	GE	1084.311	188.58	204,479.37		0.59%		29.30%	
HP Inc	HPQ	963.718	35.87	34,568.56	0.09%	3.07%	0.00%	1.05%	0.00%
Home Depot Inc/The	HD	993.293	405.2	402,482.32	1.08%	2.22%	0.02%	3.87%	0.04%
Monolithic Power Systems Inc	MPWR	48.752	924.5	45,071.22		0.54%			
International Business Machines Corp	IBM	921.148	221.08	203,647.40	0.55%	3.02%	0.02%	3.90%	0.02%
Johnson & Johnson	JNJ	2407.244	162.06	390,117.96	1.05%	3.06%	0.03%	3.73%	0.04%
Lululemon Athletica Inc	LULU	117.661	271.35	31,927.31	0.09%			7.00%	0.01%
McDonald's Corp	MCD	717.343	304.51	218,438.12	0.59%	2.33%	0.01%	5.15%	0.03%
Merck & Co Inc	MRK	2534.809	113.56	287,852.91		2.71%		53.04%	
3M Co	MMM	549.354	136.7	75,096.69		2.05%		-5.37%	
American Water Works Co Inc	AWK	194.863	146.24	28,496.77	0.08%	2.09%	0.00%	7.89%	0.01%
Bank of America Corp	BAC	7759.577	39.68	307,900.02		2.62%			
Pfizer Inc	PFE	5666.695	28.94	163,994.15	0.44%	5.81%	0.03%	6.39%	0.03%
Procter & Gamble Co/The	PG	2349.708	173.2	406,969.43	1.10%	2.32%	0.03%	7.37%	0.08%
AT&T Inc	T	7170.244	22	157,745.37	0.42%	5.05%	0.02%	1.84%	0.01%
Travelers Cos Inc/The	TRV	227.931	234.12	53,363.21	0.14%	1.79%	0.00%	18.11%	0.03%
RTX Corp	RTX	1330.239	121.16	161,171.76	0.43%	2.08%	0.01%	10.23%	0.04%
Analog Devices Inc	ADI	496.493	230.17	114,277.79		1.60%		-5.82%	
Walmart Inc	WMT	8038.251	80.75	649,088.77	1.75%	1.03%	0.02%	9.24%	0.16%
Cisco Systems Inc	CSCO	3990.735	53.22	212,386.92	0.57%	3.01%	0.02%	3.40%	0.02%
Intel Corp	INTC	4276	23.46	100,314.96	0.27%			4.26%	0.01%
General Motors Co	GM	1123.922	44.84	50,396.66	0.14%	1.07%	0.00%	11.02%	0.01%
Microsoft Corp	MSFT	7433.038	430.3	3,198,436.25	8.61%	0.77%	0.07%	16.10%	1.39%
Dollar General Corp	DG	219.915	84.57	18,598.21		2.79%		-7.74%	
Cigna Group/The	CI	279.549	346.44	96,846.96	0.26%	1.62%	0.00%	11.65%	0.03%
Kinder Morgan Inc	KMI	2219.463	22.09	49,027.94	0.13%	5.21%	0.01%	6.52%	0.01%
Citigroup Inc	C	1907.795	62.6	119,427.97		3.58%		27.26%	
American International Group Inc	AIG	643.951	73.23	47,156.53	0.13%	2.18%	0.00%	12.42%	0.02%
Altria Group Inc	MO	1706.224	51.04	87,085.67	0.23%	7.99%	0.02%	4.20%	0.01%
HCA Healthcare Inc	HCA	258.074	406.43	104,889.02	0.28%	0.65%	0.00%	10.81%	0.03%
International Paper Co	IP	347.379	48.85	16,969.46		3.79%		-2.00%	
Hewlett Packard Enterprise Co	HPE	1298.669	20.46	26,570.77	0.07%	2.54%	0.00%	2.42%	0.00%
Abbott Laboratories	ABT	1739.897	114.01	198,365.66	0.53%	1.93%	0.01%	8.12%	0.04%
Aflac Inc	AFL	560.026	111.8	62,610.91	0.17%	1.79%	0.00%	9.37%	0.02%
Air Products and Chemicals Inc	APD	222.315	295.9699	65,798.55	0.18%	2.39%	0.00%	9.52%	0.02%
Super Micro Computer Inc	SMCI	585.565	41.64	24,382.93				69.00%	
Royal Caribbean Cruises Ltd	RCL	257.42	177.36	45,656.01		0.90%		30.00%	
Hess Corp	HES	308.115	135.8	41,842.02	0.11%	1.47%	0.00%	16.00%	0.02%
Archer-Daniels-Midland Co	ADM	478.142	59.74	28,564.20		3.35%		-3.62%	
Automatic Data Processing Inc	ADP	407.826	276.73	112,857.69		2.02%			
Verisk Analytics Inc	VRSK	142.424	267.96	38,163.94	0.10%	0.58%	0.00%	13.00%	0.01%
AutoZone Inc	AZO	17.083	3150.04	53,812.13	0.14%			13.50%	0.02%
Linde PLC	LIN	477.503	476.86	227,702.08	0.61%	1.17%	0.01%	11.76%	0.07%
Avery Dennison Corp	AVY	80.519	220.76	17,775.37	0.05%	1.59%	0.00%	12.84%	0.01%
Enphase Energy Inc	ENPH	135.422	113.02	15,305.39	0.04%			7.45%	0.00%
MSCI Inc	MSCI	78.65	582.93	45,847.44	0.12%	1.10%	0.00%	12.00%	0.01%
Ball Corp	BALL	303.565	67.91	20,615.10	0.06%	1.18%	0.00%	13.35%	0.01%
Axon Enterprise Inc	AXON	75.574	399.6	30,199.37				20.81%	
Dayforce Inc	DAY	158.1	61.25	9,683.63					
Carrier Global Corp	CARR	902.752	80.49	72,662.51	0.20%	0.94%	0.00%	6.74%	0.01%
Bank of New York Mellon Corp/The	BK	737.957	71.86	53,029.59	0.14%	2.62%	0.00%	10.55%	0.02%
Otis Worldwide Corp	OTIS	400.555	103.94	41,633.69	0.11%	1.50%	0.00%	10.00%	0.01%
Baxter International Inc	BAX	510.178	37.97	19,371.46	0.05%	3.06%	0.00%	3.50%	0.00%
Becton Dickinson & Co	BDX	289.042	241.1	69,688.03	0.19%	1.58%	0.00%	8.34%	0.02%
Berkshire Hathaway Inc	BRK/B	1325.193	460.26	609,933.33					
Best Buy Co Inc	BBY	214.725	103.3	22,181.09	0.06%	3.64%	0.00%	4.17%	0.00%
Boston Scientific Corp	BSX	1472.626	83.8	123,406.06	0.33%			12.58%	0.04%
Bristol-Myers Squibb Co	BMY	2027.395	51.74	104,897.42		4.64%		-2.61%	
Brown-Forman Corp	BF/B	303.537	49.2	14,934.02		1.77%		-2.38%	
Coterra Energy Inc	CTRA	739.274	23.95	17,705.61	0.05%	3.51%	0.00%	10.06%	0.00%
Hilton Worldwide Holdings Inc	HLT	246.427	230.5	56,801.42	0.15%	0.26%	0.00%	14.97%	0.02%
Carnival Corp	CCL	1154.165	18.48	21,328.97					
Qorvo Inc	QRVO	94.861	103.3	9,799.14	0.03%			17.09%	0.00%
Builders FirstSource Inc	BLDR	116.454	193.86	22,575.77	0.06%			1.45%	0.00%
UDR Inc	UDR	329.824	45.34	14,954.22	0.04%	3.75%	0.00%	1.85%	0.00%
Clorox Co/The	CLX	123.862	162.91	20,178.36	0.05%	3.00%	0.00%	11.33%	0.01%
Paycom Software Inc	PAYC	57.432	166.57	9,566.45	0.03%	0.90%	0.00%	9.41%	0.00%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
CMS Energy Corp	CMS	298.635	70.63	21,092.59	0.06%	2.92%	0.00%	7.28%	0.00%
Colgate-Palmolive Co	CL	817.087	103.81	84,821.80	0.23%	1.93%	0.00%	8.73%	0.02%
EPAM Systems Inc	EPAM	56.935	199.03	11,331.77	0.03%			5.29%	0.00%
Conagra Brands Inc	CAG	479.05	32.52	15,578.71	0.04%	4.31%	0.00%	1.81%	0.00%
Airbnb Inc	ABNB	440.002	126.81	55,796.65	0.15%			19.84%	0.03%
Consolidated Edison Inc	ED	346.147	104.13	36,044.29	0.10%	3.19%	0.00%	5.58%	0.01%
Corning Inc	GLW	855.701	45.15	38,634.90	0.10%	2.48%	0.00%	13.57%	0.01%
GoDaddy Inc	GDDY	140.973	156.78	22,101.75					
Cummins Inc	CMI	137.048	323.79	44,374.77	0.12%	2.25%	0.00%	8.28%	0.01%
Caesars Entertainment Inc	CZR	216.338	41.74	9,029.95				-28.25%	
Danaher Corp	DHR	722.213	278.02	200,789.66	0.54%	0.39%	0.00%	1.89%	0.01%
Target Corp	TGT	460.675	155.86	71,800.81	0.19%	2.87%	0.01%	14.38%	0.03%
Deere & Co	DE	273.6	417.33	114,181.49		1.41%		-9.99%	
Dominion Energy Inc	D	838.938	57.79	48,482.23		4.62%		21.64%	
Dover Corp	DOV	137.458	191.74	26,356.20	0.07%	1.07%	0.00%	7.72%	0.01%
Alliant Energy Corp	LNT	256.5	60.69	15,566.99	0.04%	3.16%	0.00%	7.34%	0.00%
Steel Dynamics Inc	STLD	154.303	126.08	19,454.52		1.46%		-4.43%	
Duke Energy Corp	DUK	771	115.3	88,896.30	0.24%	3.63%	0.01%	6.78%	0.02%
Regency Centers Corp	REG	181.497	72.23	13,109.53	0.04%	3.71%	0.00%	3.79%	0.00%
Eaton Corp PLC	ETN	398.1	331.44	131,946.26	0.36%	1.13%	0.00%	14.60%	0.05%
Ecolab Inc	ECL	284.538	255.33	72,651.09	0.20%	0.89%	0.00%	15.76%	0.03%
Revvity Inc	RVTY	123.337	127.75	15,756.30	0.04%	0.22%	0.00%	9.44%	0.00%
Dell Technologies Inc	DELL	333.874	118.54	39,577.42	0.11%	1.50%	0.00%	9.83%	0.01%
Emerson Electric Co	EMR	572.7	109.37	62,636.20	0.17%	1.92%	0.00%	15.10%	0.03%
EOG Resources Inc	EOG	568.6	122.93	69,898.00	0.19%	2.96%	0.01%	3.28%	0.01%
Aon PLC	AON	217.242	345.99	75,163.56	0.20%	0.78%	0.00%	11.10%	0.02%
Entergy Corp	ETR	213.831	131.61	28,142.30	0.08%	3.43%	0.00%	7.17%	0.01%
Equifax Inc	EFX	123.736	293.86	36,361.06		0.53%			
EQT Corp	EQT	594.021	36.64	21,764.93		1.72%			
IQVIA Holdings Inc	IQV	182.3	236.97	43,199.63	0.12%			10.83%	0.01%
Gartner Inc	IT	77.06	506.76	39,050.93	0.11%			7.00%	0.01%
FedEx Corp	FDX	244.323	273.68	66,866.32	0.18%	2.02%	0.00%	12.33%	0.02%
FMC Corp	FMC	124.824	65.94	8,230.89	0.02%	3.52%	0.00%	15.67%	0.00%
Brown & Brown Inc	BRO	285.261	103.6	29,553.04	0.08%	0.50%	0.00%	10.85%	0.01%
Ford Motor Co	F	3904.398	10.56	41,230.44	0.11%	5.68%	0.01%	1.34%	0.00%
NextEra Energy Inc	NEE	2055	84.53	173,709.15	0.47%	2.44%	0.01%	8.78%	0.04%
Franklin Resources Inc	BEN	522.998	20.15	10,538.41	0.03%	6.15%	0.00%	3.00%	0.00%
Garmin Ltd	GRMN	192.214	176.03	33,835.43	0.09%	1.70%	0.00%	9.55%	0.01%
Freeport-McMoRan Inc	FCX	1436.856	49.92	71,727.85	0.19%	1.20%	0.00%	17.59%	0.03%
Dexcom Inc	DXCM	400.727	67.04	26,864.74				21.07%	
General Dynamics Corp	GD	274.778	302.2	83,037.91	0.22%	1.88%	0.00%	15.55%	0.03%
General Mills Inc	GIS	555.159	73.85	40,998.49	0.11%	3.25%	0.00%	2.45%	0.00%
Genuine Parts Co	GPC	139.318	139.68	19,459.94		2.86%			
Atmos Energy Corp	ATO	155.233	138.71	21,532.37		2.32%			
WW Grainger Inc	GWW	48.826	1038.81	50,720.94		0.79%			
Halliburton Co	HAL	882.829	29.05	25,646.18	0.07%	2.34%	0.00%	8.17%	0.01%
L3Harris Technologies Inc	LHX	189.705	237.87	45,125.13	0.12%	1.95%	0.00%	8.77%	0.01%
Healthpeak Properties Inc	DOC	699.291	22.87	15,992.79	0.04%	5.25%	0.00%	5.33%	0.00%
Insulet Corp	PODD	70.115	232.75	16,319.27				20.81%	
Catalent Inc	CTLT	181.464	60.57	10,991.27					
Fortive Corp	FTV	350.342	78.93	27,652.49	0.07%	0.41%	0.00%	10.49%	0.01%
Hershey Co/The	HSY	147.674	191.78	28,320.92	0.08%	2.86%	0.00%	2.21%	0.00%
Synchrony Financial	SYF	395.227	49.88	19,713.92		2.00%		64.00%	
Hormel Foods Corp	HRL	548.364	31.7	17,383.14	0.05%	3.56%	0.00%	6.23%	0.00%
Arthur J Gallagher & Co	AJG	219.1	281.37	61,648.17	0.17%	0.85%	0.00%	12.78%	0.02%
Mondelez International Inc	MDLZ	1335.798	73.67	98,408.24	0.27%	2.55%	0.01%	6.93%	0.02%
CenterPoint Energy Inc	CNP	651.721	29.42	19,173.63	0.05%	2.86%	0.00%	7.62%	0.00%
Humana Inc	HUM	120.402	316.74	38,136.13		1.12%		-1.30%	
Willis Towers Watson PLC	WTW	101.556	294.53	29,911.29	0.08%	1.20%	0.00%	11.69%	0.01%
Illinois Tool Works Inc	ITW	296.9	262.07	77,808.58	0.21%	2.29%	0.00%	6.90%	0.01%
CDW Corp/DE	CDW	133.576	226.3	30,228.25	0.08%	1.10%	0.00%	7.02%	0.01%
Trane Technologies PLC	TT	225.67	388.73	87,724.70	0.24%	0.86%	0.00%	15.56%	0.04%
Interpublic Group of Cos Inc/The	IPG	375.591	31.63	11,879.94	0.03%	4.17%	0.00%	2.12%	0.00%
International Flavors & Fragrances Inc	IFF	255.659	104.93	26,826.30	0.07%	1.52%	0.00%	2.12%	0.00%
Generac Holdings Inc	GNRC	60.153	158.88	9,557.11	0.03%			7.00%	0.00%
NXP Semiconductors NV	NXPI	254.733	240.01	61,138.47	0.16%	1.69%	0.00%	5.89%	0.01%
Kellanova	K	344.685	80.71	27,819.53	0.07%	2.82%	0.00%	9.29%	0.01%
Broadridge Financial Solutions Inc	BR	116.709	215.03	25,095.94		1.64%			
Kimberly-Clark Corp	KMB	336.804	142.28	47,920.47	0.13%	3.43%	0.00%	8.36%	0.01%
Kimco Realty Corp	KIM	674.116	23.22	15,652.97	0.04%	4.13%	0.00%	3.63%	0.00%
Oracle Corp	ORCL	2771.063	170.4	472,189.14	1.27%	0.94%	0.01%	11.95%	0.15%
Kroger Co/The	KR	723.486	57.3	41,455.75	0.11%	2.23%	0.00%	3.11%	0.00%
Lennar Corp	LEN	241.703	187.48	45,314.48	0.12%	1.07%	0.00%	9.07%	0.01%
Eli Lilly & Co	LLY	950.426	885.94	842,020.41		0.59%		33.00%	
Charter Communications Inc	CHTR	142.741	324.08	46,259.50	0.12%			7.07%	0.01%
Loews Corp	L	219.517	79.05	17,352.82		0.32%			
Lowe's Cos Inc	LOW	567.294	270.85	153,651.58		1.70%		-0.19%	
Hubbell Inc	HUBB	53.681	428.35	22,994.26		1.14%			
IDEX Corp	IEX	75.703	214.5	16,238.29		1.29%			
Marsh & McLennan Cos Inc	MMC	491.756	223.09	109,705.85	0.30%	1.46%	0.00%	9.10%	0.03%
Masco Corp	MAS	218.249	83.94	18,319.82	0.05%	1.38%	0.00%	7.76%	0.00%
S&P Global Inc	SPGI	320.2	516.62	165,421.72	0.45%	0.70%	0.00%	14.00%	0.06%
Medtronic PLC	MDT	1282.49	90.03	115,462.57	0.31%	3.11%	0.01%	5.66%	0.02%
Viatris Inc	VTRS	1193.52	11.61	13,856.77		4.13%		-3.41%	
CVS Health Corp	CVS	1257.979	62.88	79,101.72	0.21%	4.23%	0.01%	1.82%	0.00%
DuPont de Nemours Inc	DD	417.495	89.11	37,202.98	0.10%	1.71%	0.00%	2.50%	0.00%
Micron Technology Inc	MU	1108.841	103.71	114,997.90		0.44%		53.55%	
Motorola Solutions Inc	MSI	166.841	449.63	75,016.72	0.20%	0.87%	0.00%	9.36%	0.02%
Cboe Global Markets Inc	CBOE	104.634	204.87	21,436.37	0.06%	1.23%	0.00%	13.78%	0.01%
Newmont Corp	NEM	1152.488	53.45	61,600.48		1.87%		40.36%	
NIKE Inc	NKE	1201.462	88.4	106,209.24	0.29%	1.67%	0.00%	4.53%	0.01%
NiSource Inc	NI	448.51	34.65	15,540.87	0.04%	3.06%	0.00%	7.90%	0.00%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Norfolk Southern Corp	NSC	226.096	248.5	56,184.86	0.15%	2.17%	0.00%	9.92%	0.02%
Principal Financial Group Inc	PFG	231.584	85.9	19,893.07	0.05%	3.35%	0.00%	13.00%	0.01%
Eversource Energy	ES	357.385	68.05	24,320.05	0.07%	4.20%	0.00%	5.46%	0.00%
Northrop Grumman Corp	NOC	146.245	528.07	77,227.60	0.21%	1.56%	0.00%	8.68%	0.02%
Wells Fargo & Co	WFC	3403.77	56.49	192,278.97	0.52%	2.83%	0.01%	7.95%	0.04%
Nucor Corp	NUE	237.338	150.34	35,681.39		1.44%		-1.63%	
Occidental Petroleum Corp	OXY	916.197	51.54	47,220.79		1.71%		24.00%	
Omnicom Group Inc	OMC	195.649	103.39	20,228.15	0.05%	2.71%	0.00%	5.45%	0.00%
ONEOK Inc	OKE	584.074	91.13	53,226.66	0.14%	4.35%	0.01%	2.95%	0.00%
Raymond James Financial Inc	RJF	205.943	122.01	25,127.11	0.07%	1.48%	0.00%	13.70%	0.01%
PG&E Corp	PCG	2137.461	19.77	42,257.60	0.11%	0.20%	0.00%	9.84%	0.01%
Parker-Hannifin Corp	PH	128.67	631.82	81,296.28	0.22%	1.03%	0.00%	13.44%	0.03%
Rollins Inc	ROL	484.314	50.58	24,496.60	0.07%	1.19%	0.00%	14.00%	0.01%
PPL Corp	PPL	737.773	33.08	24,405.53	0.07%	3.11%	0.00%	7.01%	0.00%
ConocoPhillips	COP	1161.25	105.28	122,256.40	0.33%	2.96%	0.01%	13.00%	0.04%
PulteGroup Inc	PHM	207.524	143.53	29,785.92	0.08%	0.56%	0.00%	8.99%	0.01%
Pinnacle West Capital Corp	PNW	113.612	88.59	10,064.89	0.03%	3.97%	0.00%	8.22%	0.00%
PNC Financial Services Group Inc/The	PNC	397.496	184.85	73,477.14	0.20%	3.46%	0.01%	18.04%	0.04%
PPG Industries Inc	PPG	233.3	132.46	30,902.92	0.08%	2.05%	0.00%	8.33%	0.01%
Progressive Corp/The	PGR	585.667	253.76	148,618.86		0.16%		39.61%	
Veralto Corp	VLTO	247.106	111.86	27,641.28		0.32%			
Public Service Enterprise Group Inc	PEG	498.162	89.21	44,441.03	0.12%	2.69%	0.00%	7.47%	0.01%
Cooper Cos Inc/The	COO	199.156	110.34	21,974.87	0.06%			12.43%	0.01%
Edison International	EIX	383.925	87.09	33,436.03	0.09%	3.58%	0.00%	7.36%	0.01%
Schlumberger NV	SLB	1419.841	41.95	59,562.33	0.16%	2.62%	0.00%	12.22%	0.02%
Charles Schwab Corp/The	SCHW	1778.445	64.81	115,261.02	0.31%	1.54%	0.00%	14.04%	0.04%
Sherwin-Williams Co/The	SHW	252.258	381.67	96,279.31	0.26%	0.75%	0.00%	9.88%	0.03%
West Pharmaceutical Services Inc	WST	72.542	300.16	21,774.21	0.06%	0.27%	0.00%	2.89%	0.00%
J M Smucker Co/The	SJM	106.406	121.1	12,885.77	0.03%	3.57%	0.00%	6.07%	0.00%
Snap-on Inc	SNA	52.683	289.71	15,262.79	0.04%	2.57%	0.00%	3.83%	0.00%
AMETEK Inc	AME	231.536	171.71	39,757.05	0.11%	0.65%	0.00%	7.02%	0.01%
Uber Technologies Inc	UBER	2100.937	75.16	157,906.42				60.59%	
Southern Co/The	SO	1094.633	90.18	98,714.00	0.27%	3.19%	0.01%	7.23%	0.02%
Truist Financial Corp	TFC	1339.143	42.77	57,275.15	0.15%	4.86%	0.01%	10.91%	0.02%
Southwest Airlines Co	LUV	599.157	29.63	17,753.02		2.43%			
W R Berkley Corp	WRB	380.551	56.73	21,588.66	0.06%	0.56%	0.00%	13.27%	0.01%
Stanley Black & Decker Inc	SWK	153.959	110.13	16,955.50		2.98%			
Public Storage	PSA	175.703	363.87	63,933.05	0.17%	3.30%	0.01%	2.48%	0.00%
Arista Networks Inc	ANET	314.153	383.82	120,578.20	0.32%			18.60%	0.06%
Sysco Corp	SYY	491.521	78.06	38,368.13	0.10%	2.61%	0.00%	7.00%	0.01%
Corteva Inc	CTVA	687.797	58.79	40,435.59	0.11%	1.16%	0.00%	9.85%	0.01%
Texas Instruments Inc	TXN	913.046	206.57	188,607.91		2.63%		-2.86%	
Textron Inc	TXT	187.363	88.58	16,596.61	0.04%	0.09%	0.00%	10.05%	0.00%
Thermo Fisher Scientific Inc	TMO	381.996	618.57	236,291.27	0.64%	0.25%	0.00%	8.74%	0.06%
TJX Cos Inc/The	TJX	1127.873	117.54	132,570.19	0.36%	1.28%	0.00%	8.20%	0.03%
Globe Life Inc	GL	89.82	105.91	9,512.84	0.03%	0.91%	0.00%	6.00%	0.00%
Johnson Controls International plc	JCI	668.014	77.61	51,844.57	0.14%	1.91%	0.00%	9.26%	0.01%
Ulta Beauty Inc	ULTA	47.115	389.12	18,333.39	0.05%			1.64%	0.00%
Union Pacific Corp	UNP	609.198	246.48	150,155.12	0.40%	2.17%	0.01%	10.27%	0.04%
Keysight Technologies Inc	KEYS	173.543	158.93	27,581.19				-1.19%	
UnitedHealth Group Inc	UNH	923.418	584.68	539,904.04	1.45%	1.44%	0.02%	10.44%	0.15%
Blackstone Inc	BX	720.077	153.13	110,265.39		2.14%		22.74%	
Marathon Oil Corp	MRO	559.383	26.63	14,896.37		1.65%		-5.00%	
Ventas Inc	VTR	413.154	63.68	26,309.65	0.07%	2.83%	0.00%	8.22%	0.01%
Labcorp Holdings Inc	LH	83.963	223.48	18,764.05	0.05%	1.29%	0.00%	8.45%	0.00%
Vulcan Materials Co	VMC	132.06	250.43	33,071.79	0.09%	0.73%	0.00%	19.00%	0.02%
Weyerhaeuser Co	WY	727.315	33.86	24,626.89		2.36%		-11.50%	
Williams Cos Inc/The	WMB	1218.931	45.65	55,644.20	0.15%	4.16%	0.01%	4.28%	0.01%
Constellation Energy Corp	CEG	315.121	260.02	81,937.76		0.54%		24.22%	
WEC Energy Group Inc	WEC	316.079	96.18	30,400.48	0.08%	3.47%	0.00%	7.82%	0.01%
Adobe Inc	ADBE	440.2	517.78	227,926.76	0.61%			16.34%	0.10%
Vistra Corp	VST	343.561	118.54	40,725.72		0.74%			
AES Corp/The	AES	710.924	20.06	14,261.14		3.44%			
Expeditors International of Washington Inc	EXPD	141.128	131.4	18,544.22	0.05%	1.11%	0.00%	4.39%	0.00%
Amgen Inc	AMGN	537.329	322.21	173,132.78	0.47%	2.79%	0.01%	3.52%	0.02%
Apple Inc	AAPL	15204.137	233	3,542,563.92	9.54%	0.43%	0.04%	8.04%	0.77%
Autodesk Inc	ADSK	215	275.48	59,228.20	0.16%			10.23%	0.02%
Cintas Corp	CTAS	403.258	205.88	83,022.76	0.22%	0.76%	0.00%	12.00%	0.03%
Comcast Corp	CMCSA	3863.057	41.77	161,359.89	0.43%	2.97%	0.01%	8.16%	0.04%
Molson Coors Beverage Co	TAP	192.591	57.52	11,077.83	0.03%	3.06%	0.00%	5.29%	0.00%
KLA Corp	KLAC	133.976	774.41	103,752.35	0.28%	0.75%	0.00%	14.10%	0.04%
Marriott International Inc/MD	MAR	281.523	248.6	69,986.62	0.19%	1.01%	0.00%	4.25%	0.01%
Fiserv Inc	FI	575.725	179.65	103,429.00	0.28%			11.52%	0.03%
McCormick & Co Inc/MD	MKC	252.015	82.3	20,740.83	0.06%	2.04%	0.00%	5.83%	0.00%
PACCAR Inc	PCAR	524.222	98.68	51,730.23	0.14%	1.22%	0.00%	0.48%	0.00%
Costco Wholesale Corp	COST	443.335	886.52	393,025.34	1.06%	0.52%	0.01%	9.88%	0.10%
Stryker Corp	SYK	381.075	361.26	137,667.15	0.37%	0.89%	0.00%	8.60%	0.03%
Tyson Foods Inc	TSN	285.821	59.56	17,023.50		3.29%			
Lamb Weston Holdings Inc	LW	143.671	64.74	9,301.26	0.03%	2.22%	0.00%	2.16%	0.00%
Applied Materials Inc	AMAT	824.404	202.05	166,570.83	0.45%	0.79%	0.00%	9.28%	0.04%
Cardinal Health Inc	CAH	241.962	110.0144	26,619.30	0.07%	1.84%	0.00%	9.84%	0.01%
Cincinnati Financial Corp	CINF	156.24	136.12	21,267.39	0.06%	2.38%	0.00%	7.83%	0.00%
Paramount Global	PARA	626.012	10.62	6,648.25		1.88%		49.00%	
DR Horton Inc	DHI	326.04	190.77	62,198.65	0.17%	0.63%	0.00%	8.27%	0.01%
Electronic Arts Inc	EA	264.2	143.44	37,896.85	0.10%	0.53%	0.00%	12.97%	0.01%
Erie Indemnity Co	ERIE	46.189	539.82	24,933.75		0.94%			
Fair Isaac Corp	FICO	24.519	1943.52	47,653.17				23.00%	
Fastenal Co	FAST	572.646	71.42	40,898.38		2.18%			
M&T Bank Corp	MTB	167.001	178.12	29,746.22	0.08%	3.03%	0.00%	3.87%	0.00%
Xcel Energy Inc	XEL	557.501	65.3	36,404.82	0.10%	3.35%	0.00%	7.10%	0.01%
Fifth Third Bancorp	FITB	676.797	42.84	28,993.98		3.45%		25.00%	
Gilead Sciences Inc	GILD	1244.992	83.84	104,380.13	0.28%	3.67%	0.01%	15.38%	0.04%

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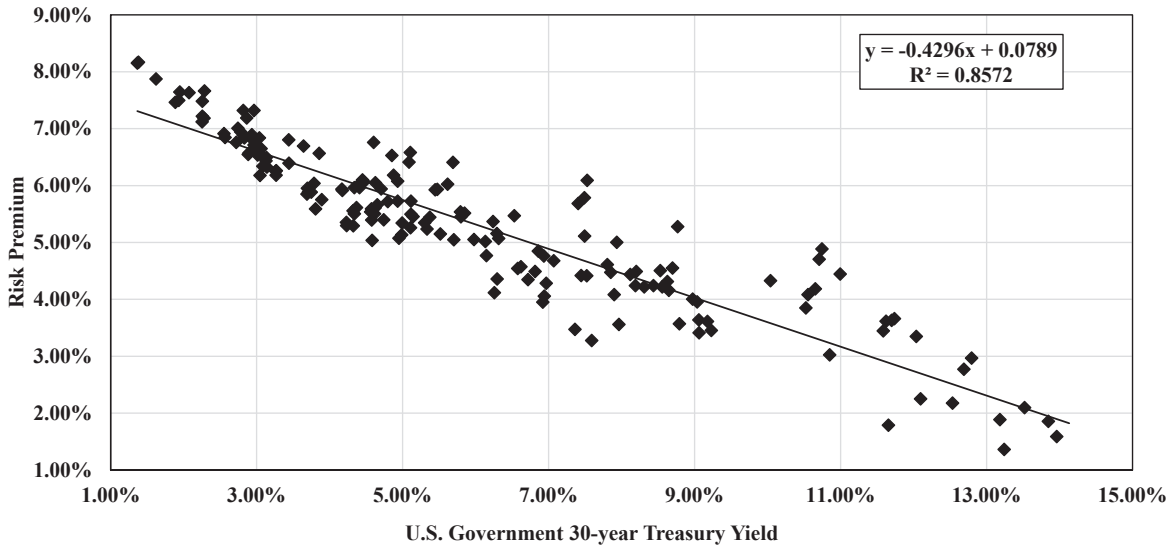
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Hasbro Inc	HAS	139.407	72.32	10,081.91		3.87%		34.01%	
Huntington Bancshares Inc/OH	HBAN	1452.433	14.7	21,350.77	0.06%	4.22%	0.00%	3.32%	0.00%
Welltower Inc	WELL	609.148	128.03	77,989.22	0.21%	2.09%	0.00%	15.65%	0.03%
Biogen Inc	BIIB	145.662	193.84	28,235.12	0.08%			6.10%	0.00%
Northern Trust Corp	NTRS	201.638	90.03	18,153.47	0.05%	3.33%	0.00%	10.11%	0.00%
Packaging Corp of America	PKG	89.812	215.4	19,345.50	0.05%	2.32%	0.00%	5.83%	0.00%
Paychex Inc	PAYX	359.742	134.19	48,273.78	0.13%	2.92%	0.00%	7.54%	0.01%
QUALCOMM Inc	QCOM	1114	170.05	189,435.70	0.51%	2.00%	0.01%	10.64%	0.05%
Ross Stores Inc	ROST	331.763	150.51	49,933.65	0.13%	0.98%	0.00%	8.85%	0.01%
IDEXX Laboratories Inc	IDXX	82.306	505.22	41,582.64	0.11%			11.25%	0.01%
Starbucks Corp	SBUX	1133.2	97.49	110,475.67	0.30%	2.34%	0.01%	9.67%	0.03%
KeyCorp	KEY	928.116	16.75	15,545.94	0.04%	4.90%	0.00%	20.00%	0.01%
Fox Corp	FOXA	224.646	42.33	9,509.27	0.03%	1.28%	0.00%	8.68%	0.00%
Fox Corp	FOX	235.581	38.8	9,140.54	0.02%	1.39%	0.00%	8.68%	0.00%
State Street Corp	STT	298.62	87.71	26,191.96	0.07%	3.47%	0.00%	8.82%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	439.691	20.51	9,018.06				50.58%	
US Bancorp	USB	1560.514	45.73	71,362.31	0.19%	4.37%	0.01%	5.00%	0.01%
A O Smith Corp	AOS	119.959	89.83	10,775.92		1.42%			
Gen Digital Inc	GEN	615.525	27.43	16,883.85	0.05%	1.82%	0.00%	10.49%	0.00%
T Rowe Price Group Inc	TROW	222.598	108.93	24,247.60	0.07%	4.55%	0.00%	7.30%	0.00%
Waste Management Inc	WM	401.315	207.6	83,312.99	0.22%	1.45%	0.00%	13.29%	0.03%
Palantir Technologies Inc	PLTR	2142.323	37.2	79,694.42				30.06%	
Constellation Brands Inc	STZ	182.192	257.69	46,949.06	0.13%	1.57%	0.00%	11.27%	0.01%
Invesco Ltd	IVZ	450.032	17.56	7,902.56	0.02%	4.67%	0.00%	9.64%	0.00%
Intuit Inc	INTU	280.292	621	174,061.33	0.47%	0.67%	0.00%	18.79%	0.09%
Morgan Stanley	MS	1620.887	104.24	168,961.26	0.46%	3.55%	0.02%	9.60%	0.04%
Microchip Technology Inc	MCHP	536.505	80.29	43,075.99		2.26%		-10.99%	
Crowdstrike Holdings Inc	CRWD	232.717	280.47	65,270.14				35.70%	
Chubb Ltd	CB	403.934	288.39	116,490.53	0.31%	1.26%	0.00%	2.20%	0.01%
Hologic Inc	HOLX	232.272	81.46	18,920.88	0.05%			8.86%	0.00%
Citizens Financial Group Inc	CFG	448.3	41.07	18,411.68		4.09%			
Jabil Inc	JBL	113.445	119.83	13,594.11	0.04%	0.27%	0.00%	10.82%	0.00%
O'Reilly Automotive Inc	ORLY	58.006	1151.6	66,799.71	0.18%			10.21%	0.02%
Allstate Corp/The	ALL	264.041	189.65	50,075.38		1.94%		168.00%	
Equity Residential	EQR	379.136	74.46	28,230.47	0.08%	3.63%	0.00%	2.83%	0.00%
BorgWarner Inc	BWA	227.769	36.29	8,265.74	0.02%	1.21%	0.00%	4.40%	0.00%
Keurig Dr Pepper Inc	KDP	1356.086	37.48	50,826.10	0.14%	2.45%	0.00%	6.90%	0.01%
Host Hotels & Resorts Inc	HST	702.44	17.6	12,362.94		4.55%		-1.83%	
Incyte Corp	INCY	192.598	66.1	12,730.73				33.16%	
Simon Property Group Inc	SPG	326.035	169.02	55,106.44	0.15%	4.85%	0.01%	1.42%	0.00%
Eastman Chemical Co	EMN	116.86	111.95	13,082.48	0.04%	2.89%	0.00%	6.10%	0.00%
AvalonBay Communities Inc	AVB	142.217	225.25	32,034.38	0.09%	3.02%	0.00%	4.93%	0.00%
Prudential Financial Inc	PRU	357	121.1	43,232.70	0.12%	4.29%	0.01%	9.48%	0.01%
United Parcel Service Inc	UPS	732.509	136.34	99,870.28	0.27%	4.78%	0.01%	0.60%	0.00%
Walgreens Boots Alliance Inc	WBA	863.275	8.96	7,734.94		11.16%		-24.69%	
STERIS PLC	STE	98.617	242.54	23,918.57		0.94%			
McKesson Corp	MCK	129.677	494.42	64,114.90	0.17%	0.57%	0.00%	11.18%	0.02%
Lockheed Martin Corp	LMT	238.358	584.56	139,334.55	0.38%	2.16%	0.01%	2.11%	0.01%
Cencora Inc	COR	196.008	225.08	44,117.48	0.12%	0.91%	0.00%	9.84%	0.01%
Capital One Financial Corp	COF	381.856	149.73	57,175.30	0.15%	1.60%	0.00%	12.30%	0.02%
Campbell Soup Co	CPB	298.106	48.92	14,583.35	0.04%	3.03%	0.00%	5.71%	0.00%
Waters Corp	WAT	59.362	359.89	21,363.79	0.06%			7.80%	0.00%
Nordson Corp	NDSN	57.182	262.63	15,017.71		1.19%			
Dollar Tree Inc	DLTR	214.992	70.32	15,118.24	0.04%			6.86%	0.00%
Darden Restaurants Inc	DRI	117.5	164.13	19,285.28	0.05%	3.41%	0.00%	9.75%	0.01%
Evergy Inc	EVRG	229.746	62.01	14,246.55	0.04%	4.14%	0.00%	5.35%	0.00%
Match Group Inc	MTCH	257.895	37.84	9,758.75				36.15%	
Domino's Pizza Inc	DPZ	34.973	430.14	15,043.29	0.04%	1.40%	0.00%	12.56%	0.01%
NVR Inc	NVR	3.078	9811.8	30,200.72	0.08%			7.60%	0.01%
NetApp Inc	NTAP	204.783	123.51	25,292.75	0.07%	1.68%	0.00%	5.34%	0.00%
Old Dominion Freight Line Inc	ODFL	214.297	198.64	42,567.96	0.11%	0.52%	0.00%	2.77%	0.00%
DaVita Inc	DVA	83.9	163.93	13,753.73	0.04%			20.00%	0.01%
Hartford Financial Services Group Inc/The	HIG	293.014	117.61	34,461.38	0.09%	1.60%	0.00%	12.37%	0.01%
Iron Mountain Inc	IRM	293.336	118.83	34,857.12		2.41%			
Estee Lauder Cos Inc/The	EL	233.432	99.69	23,270.84	0.06%	2.65%	0.00%	14.58%	0.01%
Cadence Design Systems Inc	CDNS	273.82	271.03	74,213.43	0.20%			16.20%	0.03%
Tyler Technologies Inc	TYL	42.673	583.72	24,909.08					
Universal Health Services Inc	UHS	59.462	229.01	13,617.39	0.04%	0.35%	0.00%	15.50%	0.01%
Skyworks Solutions Inc	SWKS	159.716	98.77	15,775.15		2.83%		-2.57%	
Quest Diagnostics Inc	DGX	111.317	155.25	17,281.96	0.05%	1.93%	0.00%	6.05%	0.00%
Rockwell Automation Inc	ROK	113.467	268.46	30,461.35	0.08%	1.86%	0.00%	1.73%	0.00%
Kraft Heinz Co/The	KHC	1209.079	35.11	42,450.76	0.11%	4.56%	0.01%	2.51%	0.00%
American Tower Corp	AMT	467.082	232.56	108,624.59	0.29%	2.79%	0.01%	12.31%	0.04%
Regeneron Pharmaceuticals Inc	REGN	108.417	1051.24	113,972.29	0.31%			8.67%	0.03%
Amazon.com Inc	AMZN	10495.567	186.33	1,955,639.00				34.66%	
Jack Henry & Associates Inc	JKHY	72.917	176.54	12,872.77	0.03%	1.25%	0.00%	9.73%	0.00%
Ralph Lauren Corp	RL	40.058	193.87	7,766.04	0.02%	1.70%	0.00%	11.05%	0.00%
BXP Inc	BXP	157.934	80.46	12,707.37	0.03%	4.87%	0.00%	0.90%	0.00%
Amphenol Corp	APH	1204.289	65.16	78,471.47	0.21%	1.01%	0.00%	16.86%	0.04%
Howmet Aerospace Inc	HWM	408.147	100.25	40,916.74		0.32%		22.11%	
Valero Energy Corp	VLO	320.38	135.03	43,260.91		3.17%		-24.00%	
Synopsys Inc	SNPS	153.614	506.39	77,788.59	0.21%			16.33%	0.03%
CH Robinson Worldwide Inc	CHRW	117.283	110.37	12,944.52	0.03%	2.25%	0.00%	17.48%	0.01%
Accenture PLC	ACN	626.384	353.48	221,414.22	0.60%	1.67%	0.01%	8.18%	0.05%
TransDigm Group Inc	TDG	56.111	1427.13	80,077.69	0.22%			19.57%	0.04%
Yum! Brands Inc	YUM	281.165	139.71	39,281.56	0.11%	1.92%	0.00%	11.41%	0.01%
Prologis Inc	PLD	925.911	126.28	116,924.04	0.31%	3.04%	0.01%	5.36%	0.02%
FirstEnergy Corp	FE	575.922	44.35	25,542.14	0.07%	3.83%	0.00%	7.02%	0.00%
VeriSign Inc	VRSN	97.6	189.96	18,540.10					
Quanta Services Inc	PWR	147.33	298.06	43,913.18		0.12%			
Henry Schein Inc	HSIC	126.708	72.9	9,237.01	0.02%			9.01%	0.00%
Ameren Corp	AEE	266.511	87.46	23,309.05	0.06%	3.06%	0.00%	6.08%	0.00%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
ANSYS Inc	ANSS	87.387	318.63	27,844.12					
FactSet Research Systems Inc	FDS	38.04	459.85	17,492.69	0.05%	0.90%	0.00%	9.17%	0.00%
NVIDIA Corp	NVDA	24530	121.44	2,978,923.20		0.03%		44.35%	
Cognizant Technology Solutions Corp	CTSH	495.658	77.18	38,254.88	0.10%	1.55%	0.00%	6.20%	0.01%
Intuitive Surgical Inc	ISRG	355.354	491.27	174,574.76	0.47%			17.51%	0.08%
Take-Two Interactive Software Inc	TTWO	175.283	153.71	26,942.75				60.49%	
Republic Services Inc	RSG	314.068	200.84	63,077.42	0.17%	1.16%	0.00%	10.33%	0.02%
eBay Inc	EBAY	489	65.11	31,838.79	0.09%	1.66%	0.00%	10.12%	0.01%
Goldman Sachs Group Inc/The	GS	315.8	495.11	156,355.74	0.42%	2.42%	0.01%	14.20%	0.06%
SBA Communications Corp	SBAC	107.472	240.7	25,868.51	0.07%	1.63%	0.00%	15.96%	0.01%
Sempra	SRE	633.146	83.63	52,950.00	0.14%	2.97%	0.00%	5.35%	0.01%
Moody's Corp	MCO	182.1	474.59	86,422.84	0.23%	0.72%	0.00%	13.00%	0.03%
ON Semiconductor Corp	ON	428.356	72.61	31,102.93	0.08%			1.28%	0.00%
Booking Holdings Inc	BKNG	33.524	4212.12	141,207.11	0.38%	0.83%	0.00%	14.59%	0.06%
F5 Inc	FFIV	58.284	220.2	12,834.14	0.03%			7.83%	0.00%
Akamai Technologies Inc	AKAM	151.526	100.95	15,296.55	0.04%			6.12%	0.00%
Charles River Laboratories International Inc	CRL	51.631	196.97	10,169.76	0.03%			5.20%	0.00%
MarketAxess Holdings Inc	MKTX	37.752	256.2	9,672.06	0.03%	1.16%	0.00%	4.02%	0.00%
Devon Energy Corp	DVN	626.2	39.12	24,496.94	0.07%	2.25%	0.00%	6.60%	0.00%
Bio-Techne Corp	TECH	158.665	79.93	12,682.09	0.03%	0.40%	0.00%	5.00%	0.00%
Alphabet Inc	GOOGL	5859	165.85	971,715.15	2.62%	0.48%	0.01%	15.01%	0.39%
Teleflex Inc	TFX	47.117	247.32	11,652.98	0.03%	0.55%	0.00%	7.95%	0.00%
Allegion plc	ALLE	87.128	145.74	12,698.03	0.03%	1.32%	0.00%	7.73%	0.00%
Netflix Inc	NFLX	429.165	709.27	304,393.86				35.72%	
Agilent Technologies Inc	A	287.328	148.2441	42,594.68	0.11%	0.64%	0.00%	5.74%	0.01%
Warner Bros Discovery Inc	WBD	2451.908	8.25	20,228.24				28.63%	
Elevance Health Inc	ELV	231.886	520	120,580.72	0.32%	1.25%	0.00%	11.79%	0.04%
Trimble Inc	TRMB	244.208	62.09	15,162.87					
CME Group Inc	CME	360.094	220.65	79,454.74	0.21%	2.08%	0.00%	2.96%	0.01%
Juniper Networks Inc	JNPR	329.163	38.98	12,830.77	0.03%	2.26%	0.00%	6.00%	0.00%
BlackRock Inc	BLK	148.128	949.51	140,649.02	0.38%	2.15%	0.01%	9.76%	0.04%
DTE Energy Co	DTE	206.925	128.41	26,571.24	0.07%	3.18%	0.00%	10.27%	0.01%
Nasdaq Inc	NDAQ	575.94	73.01	42,049.38	0.11%	1.31%	0.00%	10.76%	0.01%
Celanese Corp	CE	109.264	135.96	14,855.53	0.04%	2.06%	0.00%	0.56%	0.00%
Philip Morris International Inc	PM	1554.802	121.4	188,752.96	0.51%	4.45%	0.02%	9.36%	0.05%
Salesforce Inc	CRM	956	273.71	261,666.76	0.70%	0.58%	0.00%	17.52%	0.12%
Ingersoll Rand Inc	IR	403.484	98.16	39,605.99		0.08%			
Huntington Ingalls Industries Inc	HII	39.215	264.38	10,367.66	0.03%	1.97%	0.00%	7.62%	0.00%
Roper Technologies Inc	ROP	107.199	556.44	59,649.81		0.54%			
MetLife Inc	MET	700.325	82.48	57,762.81	0.16%	2.64%	0.00%	14.21%	0.02%
Tapestry Inc	TPR	232.603	46.98	10,927.69	0.03%	2.98%	0.00%	5.52%	0.00%
CSX Corp	CSX	1938.74	34.53	66,944.69	0.18%	1.39%	0.00%	8.83%	0.02%
Edwards Lifesciences Corp	EW	602.4	65.99	39,752.38	0.11%			8.56%	0.01%
Ameriprise Financial Inc	AMP	98.189	469.81	46,130.17	0.12%	1.26%	0.00%	16.59%	0.02%
Zebra Technologies Corp	ZBRA	51.58	370.32	19,101.11					
Zimmer Biomet Holdings Inc	ZBH	203.652	107.95	21,984.23	0.06%	0.89%	0.00%	6.46%	0.00%
CBRE Group Inc	CBRE	306.431	124.48	38,144.53					
Camden Property Trust	CPT	106.635	123.53	13,172.62	0.04%	3.34%	0.00%	1.87%	0.00%
Mastercard Inc	MA	916.711	493.8	452,671.89	1.22%	0.53%	0.01%	15.18%	0.19%
CarMax Inc	KMX	154.924	77.38	11,988.02	0.03%			17.91%	0.01%
Intercontinental Exchange Inc	ICE	574.142	160.64	92,230.17	0.25%	1.12%	0.00%	9.95%	0.02%
Smurfit WestRock PLC	SW	519.96	49.42	25,696.42	0.07%	2.45%	0.00%	1.00%	0.00%
Fidelity National Information Services Inc	FIS	545.566	83.75	45,691.15		1.72%		22.20%	
Chipotle Mexican Grill Inc	CMG	1369.476	57.62	78,909.21				22.64%	
Wynn Resorts Ltd	WYNN	110.992	95.88	10,641.91		1.04%		-12.14%	
Live Nation Entertainment Inc	LYV	232.114	109.49	25,414.16				32.54%	
Assurant Inc	AIZ	51.793	198.86	10,299.56	0.03%	1.45%	0.00%	7.14%	0.00%
NRG Energy Inc	NRG	206.38	91.1	18,801.22	0.05%	1.79%	0.00%	4.00%	0.00%
Regions Financial Corp	RF	915.125	23.33	21,349.87	0.06%	4.29%	0.00%	4.68%	0.00%
Monster Beverage Corp	MNST	979.544	52.17	51,102.81	0.14%			10.18%	0.01%
Mosaic Co/The	MOS	318.638	26.78	8,533.13		3.14%		-21.74%	
Baker Hughes Co	BKR	993.424	36.15	35,912.28		2.32%		27.42%	
Expedia Group Inc	EXPE	124.656	148.02	18,451.58	0.05%			19.59%	0.01%
CF Industries Holdings Inc	CF	180.412	85.8	15,479.35		2.33%		-9.54%	
Leidos Holdings Inc	LDOS	134.714	163	21,958.38	0.06%	0.93%	0.00%	11.76%	0.01%
APA Corp	APA	369.905	24.46	9,047.88		4.09%		-7.60%	
Alphabet Inc	GOOG	5585	167.19	933,756.15	2.52%	0.48%	0.01%	15.01%	0.38%
First Solar Inc	FSLR	107.047	249.44	26,701.80				41.25%	
Discover Financial Services	DFS	251.072	140.29	35,222.89	0.09%	2.00%	0.00%	11.62%	0.01%
Visa Inc	V	1670.445	274.95	459,288.85	1.24%	0.76%	0.01%	12.33%	0.15%
Mid-America Apartment Communities Inc	MAA	116.876	158.9	18,571.60	0.05%	3.70%	0.00%	0.65%	0.00%
Xylem Inc/NY	XYL	242.893	135.03	32,797.84		1.07%			
Marathon Petroleum Corp	MPC	334.684	162.91	54,523.37		2.03%		-13.00%	
Advanced Micro Devices Inc	AMD	1618.482	164.08	265,560.53				25.66%	
Tractor Supply Co	TSCO	107.869	290.93	31,382.33	0.08%	1.51%	0.00%	5.68%	0.00%
ResMed Inc	RMD	146.932	244.12	35,869.04	0.10%	0.87%	0.00%	11.49%	0.01%
Mettler-Toledo International Inc	MTD	21.357	1499.7	32,029.09	0.09%			9.15%	0.01%
Jacobs Solutions Inc	J	124.248	130.9	16,264.06	0.04%	0.89%	0.00%	10.87%	0.00%
Copart Inc	CPRT	963.287	52.4	50,476.24					
VICI Properties Inc	VICI	1043.137	33.31	34,746.89	0.09%	5.19%	0.00%	1.83%	0.00%
Fortinet Inc	FTNT	764.908	77.55	59,318.62	0.16%			8.66%	0.01%
Albemarle Corp	ALB	117.533	94.71	11,131.55		1.71%		35.42%	
Moderna Inc	MRNA	384.396	66.83	25,689.18	0.07%			16.57%	0.01%
Essex Property Trust Inc	ESS	64.218	295.42	18,971.28	0.05%	3.32%	0.00%	3.49%	0.00%
CoStar Group Inc	CSGP	409.817	75.44	30,916.59					
Realty Income Corp	O	870.868	63.1565	55,000.97	0.15%	5.01%	0.01%	3.85%	0.01%
Westinghouse Air Brake Technologies Corp	WAB	175.183	181.77	31,843.01	0.09%	0.44%	0.00%	16.12%	0.01%
Pool Corp	POOL	38.258	376.8	14,415.61		1.27%		-0.04%	
Western Digital Corp	WDC	343.452	68.29	23,454.34				-10.00%	
PepsiCo Inc	PEP	1373.572	170.05	233,575.92	0.63%	3.19%	0.02%	6.97%	0.04%
TE Connectivity PLC	TEL	380.372	150.99	57,432.37	0.15%	1.72%	0.00%	7.43%	0.01%
Diamondback Energy Inc	FANG	295.694	172.4	50,977.65	0.14%	5.43%	0.01%	8.34%	0.01%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Palo Alto Networks Inc	PANW	325.6	341.8	111,290.08	0.30%			11.52%	0.03%
ServiceNow Inc	NOW	206	894.39	184,244.34					
Church & Dwight Co Inc	CHD	244.815	104.72	25,637.03	0.07%	1.08%	0.00%	7.35%	0.01%
Federal Realty Investment Trust	FRT	83.67	113.87	9,527.50	0.03%	3.86%	0.00%	4.97%	0.00%
Amentum Holdings Inc	AMTM	153.28	32.25	4,943.28					
MGM Resorts International	MGM	303.77	39.09	11,874.37				20.60%	
American Electric Power Co Inc	AEP	532.12	102.6	54,595.51	0.15%	3.43%	0.01%	6.25%	0.01%
Invitation Homes Inc	INVH	612.594	35.26	21,600.06	0.06%	3.18%	0.00%	4.16%	0.00%
PTC Inc	PTC	120.135	180.66	21,703.59	0.06%			14.76%	0.01%
JB Hunt Transport Services Inc	JBHT	101.987	172.33	17,575.42	0.05%	1.00%	0.00%	9.73%	0.00%
Lam Research Corp	LRCX	129.611	816.08	105,772.94	0.28%	1.13%	0.00%	16.29%	0.05%
Mohawk Industries Inc	MHK	63.117	160.68	10,141.64	0.03%			4.45%	0.00%
Pentair PLC	PNR	165.498	97.79	16,184.05	0.04%	0.94%	0.00%	12.50%	0.01%
GE HealthCare Technologies Inc	GEHC	456.662	93.85	42,857.73	0.12%	0.13%	0.00%	10.92%	0.01%
Vertex Pharmaceuticals Inc	VRTX	258.102	465.08	120,038.08	0.32%			11.00%	0.04%
Amcor PLC	AMCR	1445.343	11.33	16,375.74	0.04%	4.41%	0.00%	3.71%	0.00%
Meta Platforms Inc	META	2184.729	572.44	1,250,626.27	3.37%	0.35%	0.01%	19.80%	0.67%
T-Mobile US Inc	TMUS	1166.784	206.36	240,777.55	0.65%	1.71%	0.01%	5.00%	0.03%
United Rentals Inc	URI	66.136	809.73	53,552.30	0.14%	0.81%	0.00%	7.45%	0.01%
Honeywell International Inc	HON	649.671	206.71	134,293.49	0.36%	2.19%	0.01%	8.65%	0.03%
Alexandria Real Estate Equities Inc	ARE	174.926	118.75	20,772.46	0.06%	4.38%	0.00%	3.03%	0.00%
Delta Air Lines Inc	DAL	645.419	50.79	32,780.83	0.09%	1.18%	0.00%	8.44%	0.01%
Seagate Technology Holdings PLC	STX	210.49	109.53	23,054.97		2.56%			
United Airlines Holdings Inc	UAL	328.803	57.06	18,761.50	0.05%			2.27%	0.00%
News Corp	NWS	190.083	27.95	5,312.82		0.72%			
Centene Corp	CNC	526.03	75.28	39,599.54	0.11%			4.40%	0.00%
Martin Marietta Materials Inc	MLM	61.117	538.25	32,896.23	0.09%	0.59%	0.00%	7.47%	0.01%
Teradyne Inc	TER	163.176	133.93	21,854.16	0.06%	0.36%	0.00%	16.14%	0.01%
PayPal Holdings Inc	PYPL	1022.333	78.03	79,772.64	0.21%			12.03%	0.03%
Tesla Inc	TSLA	3194.64	261.63	835,813.66				-11.00%	
Arch Capital Group Ltd	ACGL	376.058	111.88	42,073.37	0.11%			6.13%	0.01%
KKR & Co Inc	KKR	887.44	130.58	115,881.92		0.54%		29.00%	
Dow Inc	DOW	703.268	54.63	38,419.53		5.13%		-2.67%	
Everest Group Ltd	EG	43.274	391.83	16,956.05	0.05%	2.04%	0.00%	2.33%	0.00%
Teledyne Technologies Inc	TDY	46.784	437.66	20,475.49	0.06%			7.34%	0.00%
GE Vernova Inc	GEV	274.802	254.98	70,069.01				80.76%	
News Corp	NWSA	379.531	26.63	10,106.91		0.75%			
Exelon Corp	EXC	999.735	40.55	40,539.25	0.11%	3.75%	0.00%	5.31%	0.01%
Global Payments Inc	GPN	254.437	102.42	26,059.44	0.07%	0.98%	0.00%	8.80%	0.01%
Crown Castle Inc	CCI	434.567	118.63	51,552.68	0.14%	5.28%	0.01%	1.13%	0.00%
Aptiv PLC	APTV	265.76	72.01	19,137.38	0.05%			16.91%	0.01%
Align Technology Inc	ALGN	74.697	254.32	18,996.94	0.05%			9.53%	0.00%
Kenvue Inc	KVUE	1915.167	23.13	44,297.81	0.12%	3.55%	0.00%	13.58%	0.02%
Targa Resources Corp	TRGP	219.08	148.01	32,426.03	0.09%	2.03%	0.00%	16.74%	0.01%
Bunge Global SA	BG	141.651	96.64	13,689.15		2.81%		-8.59%	
Deckers Outdoor Corp	DECK	152.463	159.45	24,310.23	0.07%			10.80%	0.01%
LKQ Corp	LKQ	263.256	39.92	10,509.18		3.01%			
Zoetis Inc	ZTS	453.051	195.38	88,517.10	0.24%	0.88%	0.00%	10.36%	0.02%
Digital Realty Trust Inc	DLR	327.411	161.83	52,984.92	0.14%	3.02%	0.00%	3.21%	0.00%
Equinix Inc	EQIX	94.945	887.63	84,276.03	0.23%	1.92%	0.00%	14.03%	0.03%
Las Vegas Sands Corp	LVS	736.432	50.34	37,071.99		1.59%			
Molina Healthcare Inc	MOH	58.6	344.56	20,191.22	0.05%			11.98%	0.01%

Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Bloomberg Professional as of September 30, 2024
[5] Bloomberg Professional as of September 30, 2024
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of September 30, 2024
[9] Equals [7] x [8]
[10] Bloomberg Professional, as of September 30, 2024
[11] Equals [7] x [10]



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9258710
R Square	0.8572370
Adjusted R Square	0.8564118
Standard Error	0.0054250
Observations	175

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.03057	0.03057	1,038.79871	0.00000
Residual	173	0.00509	0.00003		
Total	174	0.03566			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0789	0.00	87.26	0.0000	0.0772	0.0807	0.0772	0.0807
U.S. Govt. 30-year Treasury	(0.4296)	0.01	(32.23)	0.0000	(0.4559)	(0.4033)	(0.4559)	(0.4033)

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.07%	6.15%	10.22%
Blue Chip Near-Term Projected Forecast (Q1 2025 - Q1 2026) [5]	4.02%	6.17%	10.19%
Blue Chip Long-Term Projected Forecast (2026-2030) [6]	4.30%	6.05%	10.35%
AVERAGE			10.25%

Notes:
[1] Regulatory Research Associates, rate cases through September 30, 2024
[2] S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] S&P Capital IQ Pro, 30-day average as of September 30, 2024
[5] Blue Chip Financial Forecasts, Vol. 43, No. 6, October 1, 2024, at 2
[6] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.078948 + (-0.429628 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized Natural Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
1980.1	13.45%	11.66%	1.79%
1980.2	14.38%	10.52%	3.85%
1980.3	13.87%	10.85%	3.02%
1980.4	14.35%	12.10%	2.25%
1981.1	14.71%	12.53%	2.18%
1981.2	14.61%	13.24%	1.36%
1981.3	14.86%	14.13%	0.72%
1981.4	15.70%	13.85%	1.86%
1982.1	15.55%	13.96%	1.59%
1982.2	15.62%	13.52%	2.10%
1982.3	15.77%	12.79%	2.97%
1982.4	15.63%	10.75%	4.89%
1983.1	15.41%	10.71%	4.71%
1983.2	14.84%	10.65%	4.19%
1983.3	15.24%	11.62%	3.62%
1983.4	15.40%	11.74%	3.66%
1984.1	15.39%	12.04%	3.35%
1984.2	15.07%	13.18%	1.89%
1984.3	15.46%	12.69%	2.77%
1984.4	15.33%	11.70%	3.63%
1985.1	15.03%	11.58%	3.45%
1985.2	15.44%	11.00%	4.45%
1985.3	14.64%	10.55%	4.08%
1985.4	14.37%	10.04%	4.33%
1986.1	14.05%	8.77%	5.28%
1986.2	13.28%	7.49%	5.79%
1986.3	13.09%	7.40%	5.69%
1986.4	13.62%	7.53%	6.09%
1987.1	12.61%	7.49%	5.11%
1987.2	13.04%	8.53%	4.51%
1987.3	12.70%	9.06%	3.64%
1987.4	12.69%	9.23%	3.46%
1988.1	12.94%	8.63%	4.31%
1988.2	12.48%	9.06%	3.41%
1988.3	12.79%	9.18%	3.61%
1988.4	12.98%	8.97%	4.00%
1989.1	12.99%	9.04%	3.96%
1989.2	13.25%	8.70%	4.55%
1989.3	12.56%	8.12%	4.44%
1989.4	12.94%	7.93%	5.00%
1990.1	12.68%	8.44%	4.24%
1990.2	12.81%	8.65%	4.16%
1990.3	12.36%	8.79%	3.57%
1990.4	12.78%	8.56%	4.22%
1991.1	12.69%	8.20%	4.49%
1991.2	12.53%	8.31%	4.22%
1991.3	12.43%	8.19%	4.24%
1991.4	12.33%	7.85%	4.48%
1992.1	12.42%	7.81%	4.61%
1992.2	11.98%	7.90%	4.09%
1992.3	11.87%	7.45%	4.42%
1992.4	11.94%	7.52%	4.42%
1993.1	11.75%	7.07%	4.68%
1993.2	11.71%	6.86%	4.85%
1993.3	11.39%	6.32%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.58%	4.54%
1994.2	10.84%	7.36%	3.47%
1994.3	10.87%	7.59%	3.28%

	[1]	[2]	[3]
Quarter	Average Authorized Natural Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
1994.4	11.53%	7.96%	3.56%
1995.2	11.00%	6.94%	4.06%
1995.3	11.07%	6.72%	4.35%
1995.4	11.61%	6.24%	5.37%
1996.1	11.45%	6.29%	5.16%
1996.2	10.88%	6.92%	3.95%
1996.3	11.25%	6.97%	4.28%
1996.4	11.19%	6.62%	4.57%
1997.1	11.31%	6.82%	4.49%
1997.2	11.70%	6.94%	4.76%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.15%	4.77%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.48%	5.93%
1998.4	11.69%	5.11%	6.58%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.80%	5.45%
1999.4	10.38%	6.26%	4.12%
2000.1	10.66%	6.30%	4.36%
2000.2	11.03%	5.98%	5.05%
2000.3	11.33%	5.79%	5.54%
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.45%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.52%	5.15%
2002.2	11.64%	5.62%	6.03%
2002.3	11.50%	5.09%	6.41%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.85%	6.53%
2003.2	11.36%	4.60%	6.76%
2003.3	10.61%	5.11%	5.50%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.88%	6.18%
2004.2	10.57%	5.34%	5.24%
2004.3	10.37%	5.11%	5.26%
2004.4	10.66%	4.93%	5.73%
2005.1	10.65%	4.71%	5.94%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.42%	6.05%
2005.4	10.32%	4.65%	5.66%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	5.00%	5.34%
2006.4	10.14%	4.74%	5.40%
2007.1	10.52%	4.80%	5.72%
2007.2	10.13%	4.99%	5.14%
2007.3	10.03%	4.95%	5.08%
2007.4	10.12%	4.61%	5.50%
2008.1	10.38%	4.41%	5.97%
2008.2	10.17%	4.57%	5.59%
2008.3	10.55%	4.45%	6.10%
2008.4	10.34%	3.64%	6.69%
2009.1	10.24%	3.44%	6.80%
2009.2	10.11%	4.17%	5.94%
2009.3	9.88%	4.32%	5.56%
2009.4	10.31%	4.34%	5.97%
2010.1	10.24%	4.62%	5.61%
2010.2	9.99%	4.37%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.92%

	[1]	[2]	[3]
Quarter	Average Authorized Natural Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.70%	5.95%
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%
2012.2	9.83%	2.94%	6.89%
2012.3	9.75%	2.74%	7.01%
2012.4	10.06%	2.86%	7.19%
2013.1	9.57%	3.13%	6.44%
2013.2	9.47%	3.14%	6.33%
2013.3	9.60%	3.71%	5.89%
2013.4	9.83%	3.79%	6.04%
2014.1	9.54%	3.69%	5.85%
2014.2	9.84%	3.44%	6.39%
2014.3	9.45%	3.27%	6.18%
2014.4	10.28%	2.96%	7.32%
2015.1	9.47%	2.55%	6.91%
2015.2	9.43%	2.88%	6.55%
2015.3	9.75%	2.96%	6.79%
2015.4	9.68%	2.96%	6.71%
2016.1	9.48%	2.72%	6.76%
2016.2	9.42%	2.57%	6.85%
2016.3	9.47%	2.28%	7.19%
2016.4	9.67%	2.83%	6.84%
2017.1	9.60%	3.05%	6.55%
2017.2	9.47%	2.90%	6.57%
2017.3	10.14%	2.82%	7.32%
2017.4	9.70%	2.82%	6.88%
2018.1	9.68%	3.02%	6.66%
2018.2	9.43%	3.09%	6.34%
2018.3	9.71%	3.06%	6.65%
2018.4	9.53%	3.27%	6.26%
2019.1	9.55%	3.01%	6.54%
2019.2	9.73%	2.78%	6.94%
2019.3	9.95%	2.29%	7.67%
2019.4	9.74%	2.26%	7.48%
2020.1	9.35%	1.89%	7.46%
2020.2	9.55%	1.38%	8.17%
2020.3	9.52%	1.37%	8.15%
2020.4	9.50%	1.62%	7.87%
2021.1	9.71%	2.07%	7.63%
2021.2	9.48%	2.26%	7.22%
2021.3	9.43%	1.93%	7.50%
2021.4	9.59%	1.95%	7.65%
2022.1	9.38%	2.25%	7.12%
2022.2	9.23%	3.05%	6.18%
2022.3	9.52%	3.26%	6.26%
2022.4	9.65%	3.89%	5.75%
2023.1	9.64%	3.75%	5.89%
2023.2	9.40%	3.81%	5.59%
2023.3	9.53%	4.23%	5.30%
2023.4	9.62%	4.58%	5.04%
2024.1	9.62%	4.32%	5.29%
2024.2	9.97%	4.58%	5.40%
2024.3	9.58%	4.23%	5.35%
AVERAGE	11.35%	6.05%	5.30%
MEDIAN	10.75%	5.11%	5.47%

FLOTATION COST ADJUSTMENT

Company	Ticker	Date [i]	[1] Shares Issued (000)	[2] Offering Price	[3] Under-writing Discount [ii]	[4] Offering Expense ($000)	[5] Net Proceeds Per Share	[6] Total Flotation Costs ($000)	[7] Gross Equity Issue Before Costs ($000)	[8] Net Proceeds ($000)	[9] Flotation Cost Percentage
CMS Energy Corporation	CMS	3/30/2005	23,000	12.25	0.429	325	11.81	10,187	281,750	271,563	3.62%
CMS Energy Corporation	CMS	10/7/2004	32,775	9.10	0.319	325	8.77	10,764	298,253	287,489	3.61%
								$ 20,951	$ 580,003	$ 559,051	3.61%

[i] Offering Completion Date
[ii] Underwriting discount is calculated as the market price minus the offering price when not explicitly given in the prospectus.

The flotation cost adjustment is derived by dividing the dividend yield by 1 − F (where F = flotation costs expressed in percentage terms), or by 0.9639, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + 0.5g)}{P \times (1 - F)} + g$$

Company	Ticker	[10] Annualized Dividend	[11] Stock Price	[12] Dividend Yield	[13] Expected Dividend Yield	[14] Expected Dividend Yield Adjusted for Flotation Costs	[15] Value Line Earnings Growth	[16] Yahoo! Finance Earnings Growth	[17] Zacks Earnings Growth	[18] Average Earnings Growth	[19] Cost of Equity: Mean Growth Rate	[20] Cost of Equity Adjusted for Flotation Costs	
Atmos Energy Corporation	ATO	$ 3.22	$ 133.50	2.41%	2.50%	2.59%	7.00%	7.40%	7.00%	7.13%	9.63%	9.72%	
NiSource Inc.	NI	$ 1.06	$ 33.46	3.17%	3.30%	3.42%	9.50%	7.70%	7.00%	8.07%	11.36%	11.49%	
Northwest Natural Gas Company	NWN	$ 1.95	$ 39.87	4.89%	5.00%	5.19%	6.50%	2.80%	n/a	4.65%	9.65%	9.84%	
ONE Gas, Inc.	OGS	$ 2.64	$ 70.80	3.73%	3.81%	3.96%	3.50%	5.00%	5.00%	4.50%	8.31%	8.46%	
Southwest Gas Corporation	SWX	$ 2.48	$ 72.18	3.44%	3.55%	3.68%	10.00%	4.00%	6.00%	6.67%	10.22%	10.35%	
Spire, Inc.	SR	$ 3.02	$ 65.59	4.60%	4.73%	4.90%	4.50%	6.36%	5.00%	5.29%	10.01%	10.19%	
Mean											9.87%	10.01%	
Median											9.83%	10.02%	
Flotation Cost Adjustment (Mean)												0.14%	[21]
Flotation Cost Adjustment (Median)												0.18%	[22]

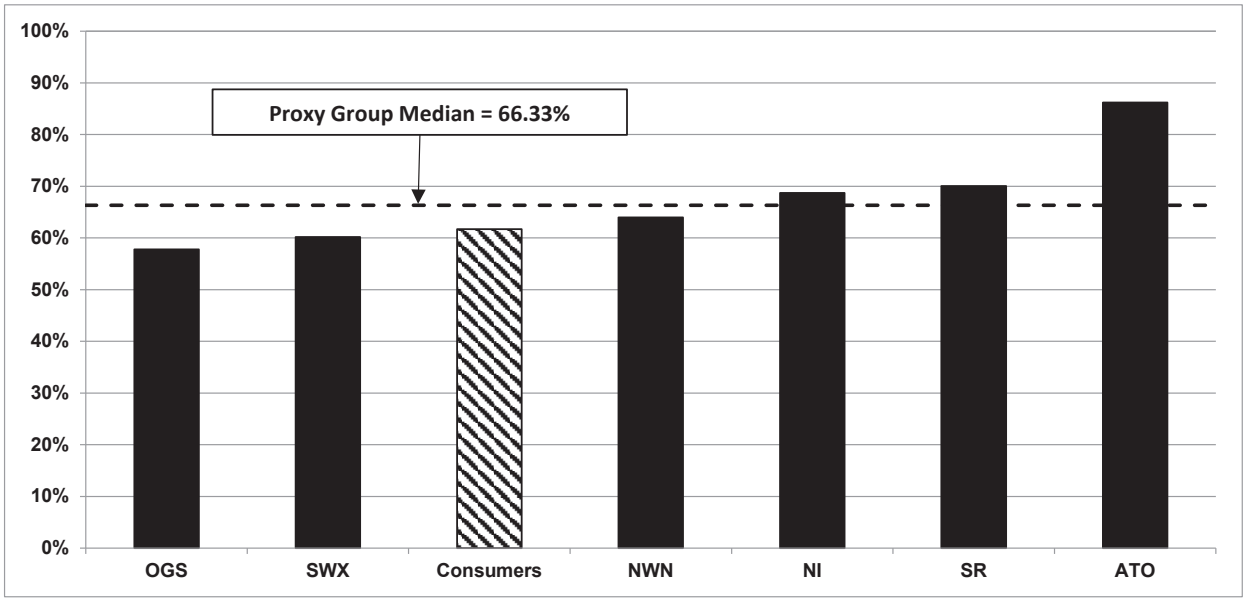
Notes:
[1] - [4] Sources: CMS Energy Corporation - Prospectus dated March 30, 2005 and Prospectus dated October 7, 2004.
[5] Equals [8]/[1]
[6] Equals [4] + ([1] x [3])
[7] Equals [1] x [2]
[8] Equals [7] - [6]
[9] Equals [6] / [7]
[10] Bloomberg Professional
[11] Bloomberg Professional, equals 30-day average as of September 30, 2024
[12] Equals [10] / [11]
[13] Equals [12] x (1 + 0.5 x [18])
[14] Equals [13] / (1 − Flotation Cost)
[15] Value Line
[16] Yahoo! Finance
[17] Zacks Investment Research
[18] Equals Average of [15], [16], [17]
[19] Equals [13] + [18]
[20] Equals [14] + [18]
[21] Equals [20] (Mean) − [19] (Mean)
[22] Equals [20] (Median) − [19] (Median)

PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF 2023 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2023	2025	2026	2027	2028	2029	Projected Cap. Ex. / 2023 Net Plant
Atmos Energy Corporation	ATO							
Capital Spending per Share			$20.25	$20.25	$20.00	$20.00	$20.00	
Common Shares Outstanding			158.00	158.00	175.00	175.00	175.00	
Capital Expenditures			$3,199.5	$3,199.5	$3,500.0	$3,500.0	$3,500.0	86.2%
Net Plant		$19,607.0						
NiSource Inc.	NI							
Capital Spending per Share			$6.50	$6.50	$7.00	$7.00	$7.00	
Common Shares Outstanding			450.00	450.00	450.00	450.00	450.00	
Capital Expenditures			$2,925.0	$2,925.0	$3,150.0	$3,150.0	$3,150.0	68.7%
Net Plant		$22,275.0						
Northwest Natural Gas Company	NWN							
Capital Spending per Share			$9.50	$9.50	$10.00	$10.00	$10.00	
Common Shares Outstanding			42.00	42.00	45.00	45.00	45.00	
Capital Expenditures			$399.0	$399.0	$450.0	$450.0	$450.0	64.0%
Net Plant		$3,358.0						
ONE Gas, Inc.	OGS							
Capital Spending per Share			$12.30	$12.30	$12.60	$12.60	$12.60	
Common Shares Outstanding			56.50	56.50	57.00	57.00	57.00	
Capital Expenditures			$695.0	$695.0	$718.2	$718.2	$718.2	57.8%
Net Plant		$6,135.2						
Southwest Gas Corporation	SWX							
Capital Spending per Share			$12.50	$12.50	$12.00	$12.00	$12.00	
Common Shares Outstanding			73.00	73.00	75.00	75.00	75.00	
Capital Expenditures			$912.5	$912.5	$900.0	$900.0	$900.0	60.19%
Net Plant		$7,518.2						
Spire, Inc.	SR							
Capital Spending per Share			$11.25	$11.25	$14.50	$14.50	$14.50	
Common Shares Outstanding			60.00	60.00	62.00	62.00	62.00	
Capital Expenditures			$675.0	$675.0	$899.0	$899.0	$899.0	70.0%
Net Plant		$5,778.9						
Consumers Energy Natural Gas Operations	Consumers							
Capital Expenditures [8]			$1,200.0	$1,200.0	$1,200.0	$1,200.0	$1,200.0	61.71%
Net Plant [9]		$9,723.5						

Notes:
[1] - [6] Value Line, as of October 31, 2024
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] Source: Exhibit A-42 (NPD-1), page 86
[9] Source: Exhibit No. A-2 (HLR-8), Schedule B-6, pg. 1

PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF 2023 NET PLANT



Projected CAPEX / 2023 Net Plant

Rank	Company		Percent
1	ONE Gas, Inc.	OGS	57.8%
2	Southwest Gas Corporation	SWX	60.2%
3	Consumers Energy Natural Gas Operations	Consumers	61.7%
4	Northwest Natural Gas Company	NWN	64.0%
5	NiSource Inc.	NI	68.7%
6	Spire, Inc.	SR	70.0%
7	Atmos Energy Corporation	ATO	86.2%
	Proxy Group Median		66.33%
	Consumers as % of Median		0.93

Notes:
Source: Exhibit A-14 (AEB-1), Schedule D-5, page 27, column [7]

COMPARISON OF
REGULATORY RISK ASSESSMENT

Company	Operating Subsidiary	State	Utility Type	[1] Test Year Convention	[2] Revenue Stabilization: Revenue Decoupling	[3] Revenue Stabilization: Formula-Based Rates	[4] Revenue Stabilization: Straight Fixed Variable Rate Design	[5] Overall Revenue Stabilization	[6] Capital Cost Recovery
Atmos Energy Corporation									
	Atmos Energy Corporation	Kansas	Gas	Historical	Partial	No	No	Yes	Yes
	Atmos Energy Corporation	Kentucky	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Atmos Energy Corporation	Louisiana	Gas	Historical	Partial	Yes	No	Yes	No
	Atmos Energy Corporation	Mississippi	Gas	Historical	Partial	Yes	No	Yes	Yes
	Atmos Energy Corporation	Tennessee	Gas	Historical	Partial	Yes	No	Yes	No
	Atmos Energy Corporation	Texas	Gas	Historical	Partial	Yes	No	Yes	Yes
NiSource Inc.									
	Northern Indiana Public Service Co.	Indiana	Electric	Fully Forecast	Partial	No	No	Yes	Yes
	Northern Indiana Public Service Co.	Indiana	Gas	Fully Forecast	No	No	No	No	Yes
	Columbia Gas of Kentucky Inc.	Kentucky	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Columbia Gas of Maryland Inc.	Maryland	Gas	Partially Forecast	Partial	No	No	Yes	Yes
	Columbia Gas of Ohio Inc.	Ohio	Gas	Partially Forecast	No	No	Yes	Yes	Yes
	Columbia Gas of Pennsylvania Inc.	Pennsylvania	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Columbia Gas of Virginia Inc.	Virginia	Gas	Historical	Partial	No	No	Yes	Yes
Northwest Natural Gas Company									
	Northwest Natural Gas Co.	Oregon	Gas	Fully Forecast	Partial	No	No	Yes	Yes
	Northwest Natural Gas Co.	Washington	Gas	Historical	No	No	No	No	No
ONE Gas, Inc.									
	Kansas Gas Service Co.	Kansas	Gas	Historical	Partial	No	No	Yes	Yes
	Oklahoma Natural Gas Co.	Oklahoma	Gas	Historical	Partial	Yes	No	Yes	No
	Texas Gas Service Co. Inc.	Texas	Gas	Historical	Partial	Yes	No	Yes	Yes
Southwest Gas Corporation									
	Southwest Gas Corporation	Arizona	Gas	Historical	Full	No	No	Yes	Yes
	Southwest Gas Corporation	California	Gas	Fully Forecast	Full	No	No	Yes	No
	Southwest Gas Corporation	Nevada	Gas	Historical	Full	No	No	Yes	Yes
Spire, Inc.									
	Spire Alabama Inc.	Alabama	Gas	Fully Forecast	Partial	Yes	No	Yes	No
	Spire Gulf Inc.	Alabama	Gas	Fully Forecast	Partial	Yes	No	Yes	No
	Spire Missouri Inc.	Missouri	Gas	Partially Forecast	Partial	No	No	Yes	Yes
Proxy Group Totals				Fully Forecast 9					
				Partially Forecast 3				Yes 22	Yes 17
				Historical 12				No 2	No 7
				% Forecast 50.0%				% Yes 91.7%	% Yes 70.8%
Consumers Energy [7]		Michigan	Gas	Projected	No	No	No	No	No

Notes:
[1] Regulatory Research Associates, Rate Case History, Company Tariffs, Company Form 10-K.
[2] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit.
[3] Company Form 10-K, Company Tariffs, S&P Capital IQ Pro
[4] Company Form 10-K, Company Tariffs, S&P Capital IQ Pro
[5] Equals IF(AND([3]=No, [4]=No, [5]=No), No, Yes)
[6] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[7] Data provided by the Company

Schedule D-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Overall Rate of Return Summary
for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-14 (MRB-1)
Schedule: D-1
Page: 1 of 1
Witness: MRBleckman
Date: December 2024

Line No.	(a) Description	(b) Amount ($000,000) (1)	(c) Capital Structure Percent Permanent Capital (2)	(d) Percent of Total Capital	(e) Cost Rate %	(f) Permanent Capital (7)	(g) Weighted Cost Total Cost % (8)	(h) Conversion Factor	(i) Pre-Tax Return (9)
1									
2	Long-Term Debt	$ 12,645	49.10%	41.19%	4.35% (3)	2.14%	1.79%	1.0000	1.79%
3									
4	Preferred Stock	37	0.14%	0.12%	4.50% (4)	0.01%	0.01%	1.3381	0.01%
5									
6	Common Shareholder's Equity	13,070	50.75%	42.58%	10.25% (5)	5.20%	4.36%	1.3381	5.84%
7									
8	Total Permanent Capital	$ 25,752	100.00%						
9									
10	Short-Term Debt	201		0.66%	4.52% (6)		0.03%	1.0000	0.03%
11									
12	Deferred Income Taxes	4,629		15.08%	0.00%		0.00%	1.0000	0.00%
13									
14	Investment Tax Credit								
15	Long-Term Debt	56		0.18%	4.35%		0.01%	1.0000	0.01%
16	Preferred Stock	0		0.00%	4.50%		0.00%	1.3381	0.00%
17	Common Equity	58		0.19%	10.25%		0.02%	1.3381	0.03%
18									
19	Total	$ 30,697		100.00%			6.22%		7.70%

(1) See Exhibit A-14 (MRB-2), Schedule D-1a, Page 1.
(2) Excludes Short-term Debt, Deferred Income Taxes, and Investment Tax Credit to calculate the rate of return for Investment Tax Credit purposes in accordance with Internal Revenue Service Income Tax Regulation Section 1.46-6.
(3) See Exhibit A-14 (MRB-4), Schedule D-2.
(4) See Exhibit A-14 (MRB-6), Schedule D-4.
(5) See Exhibit A-14 (AEB-1), Schedule D-5.
(6) See Exhibit A-14 (MRB-5), Schedule D-3, Page 1.
(7) Column (c) x column (e).
(8) Column (d) x column (e).
(9) Column (g) x column (h).

Schedule D-1a

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Structure Development
for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-14 (MRB-2)
Schedule: D-1a
Page: 1 of 4
Witness: MRBleckman
Date: December 2024

Line No.	(a) Description	(b) Historical Capital Structure 13-Month Avg. For Yr. Ended December 31, 2023 Amount Outstanding (000,000)	(c) % of Permanent Capital	(d) % of Total Capital	(e) Balances as of Dec. 31, 2023 (000,000)	(f) Test Year Adjustments (000,000)	(g) Recommended Capital Structure Amount Outstanding (000,000)	(h) % of Permanent Capital	(i) % of Total Capital
1									
2	Long-Term Debt	$ 10,135	49.10%	40.40%	$ 10,397	$ 2,248	$ 12,645	49.10%	41.19%
3									
4	Preferred Stock	37	0.18%	0.15%	37	-	37	0.14%	0.12%
5									
6	Common Equity	10,470	50.72%	41.74%	10,779	2,291	13,070	50.75%	42.58%
7									
8	Total Permanent Capital	$ 20,643	100.00%		$ 21,213	$ 4,539	$ 25,752	100.00%	
9									
10	Short-Term Debt	290		1.16%	122	79	201		0.66%
11									
12	Deferred Income Taxes	4,024		16.04%	4,103	526	4,629		15.08%
13									
14	Investment Tax Credit								
15	Long-Term Debt	63		0.25%	62	(5)	56		0.18%
16	Preferred Stock	0		0.00%	0	(0)	0		0.00%
17	Common Equity	65		0.26%	64	(6)	58		0.19%
18									
19	Total Investment Tax Credit	128		0.51%	126	(11)	115		0.37%
20									
21	Total Capitalization	$ 25,085		100.00%	$ 25,564	$ (10)	$ 30,697		100.00%

Sources and Support, by Column:

(b) Consumers Energy General Ledger 13-month average balances as of December 31, 2023.
(c) Each line 2, 4, and 6 in column (b) is divided by line 8, column (b).
(d) Each line 2, 4, 6, 10, 12, 15, 16, 17, and 19 in column (b) is divided by line 21, column (b).
(e) Consumers Energy General Ledger balances as of December 31, 2023.
(f) Line 2 Debt maturities and debt issues, line 6 Adjustment for retained earnings and equity contributions, line 10 Adjustment to project short-term debt, line 12 Adjustment to project Deferred Income Taxes balance, lines 15-17 Adjustment to project Investment Tax Credit balance.
(g) Column (e) + column (f). Represents 13-month averages.
(h) Each line 2, 4, and 6 in column (g) is divided by line 8, column (g).
(i) Each line 2, 4, 6, 10, 12, 15, 16, 17, and 19 in column (g) is divided by line 21, column (g).

Schedule D-1a

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Structure Development - Projected Long-Term Debt Balance
for the Projected Year Ending October 31, 2026
(in millions)

Case No.: U-21806
Exhibit No.: A-14 (MRB-2)
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Witness: MRBleckman
Date: December 2024

Line No.	(a) Long-Term Debt	(b) Actual Jan-23	(c) Actual Feb-23	(d) Actual Mar-23	(e) Actual Apr-23	(f) Actual May-23	(g) Actual Jun-23	(h) Actual Jul-23	(i) Actual Aug-23	(j) Actual Sep-23	(k) Actual Oct-23	(l) Actual Nov-23	(m) Actual Dec-23
1													
2	Beginning Balance	$ 9,106	$ 9,532	$ 10,232	$ 10,232	$ 10,232	$ 10,632	$ 10,332	$ 10,332	$ 10,507	$ 10,507	$ 10,507	$ 10,507
3	Add: Issuances	426	700	-	-	400	-	-	500	-	-	-	-
4	Less: Retirements	-	-	-	-	-	(300)	-	(325)	-	-	-	-
5	Subtotal	$ 9,532	$ 10,232	$ 10,232	$ 10,232	$ 10,632	$ 10,332	$ 10,332	$ 10,507	$ 10,507	$ 10,507	$ 10,507	$ 10,507
6													
7	Less: Unamortized Fees	$ (102)	(110)	(110)	(109)	(109)	(109)	(108)	(112)	(111)	(110)	(110)	(110)
8													
9	Ending Balance	$ 9,430	$ 10,122	$ 10,122	$ 10,123	$ 10,523	$ 10,223	$ 10,224	$ 10,395	$ 10,396	$ 10,397	$ 10,397	$ 10,397
10													
11													
12													
13	Long-Term Debt	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
14													
15	Beginning Balance	$ 10,507	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,807	$ 11,557	$ 11,557	$ 11,557
16	Add: Issuances	600	-	-	-	-	-	-	700	-	-	-	-
17	Less: Retirements	-	-	-	-	-	-	-	-	(250)	-	-	(52)
18	Subtotal	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,107	$ 11,807	$ 11,557	$ 11,557	$ 11,557	$ 11,505
19													
20	Less: Unamortized Fees	(115)	(114)	(113)	(113)	(112)	(112)	(111)	(116)	(116)	(115)	(115)	(115)
21													
22	Ending Balance	$ 10,992	$ 10,993	$ 10,994	$ 10,994	$ 10,995	$ 10,995	$ 10,996	$ 11,691	$ 11,441	$ 11,442	$ 11,442	$ 11,390
23													
24													
25													
26	Long-Term Debt	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
27													
28	Beginning Balance	$ 11,505	$ 11,505	$ 11,505	$ 11,505	$ 11,505	$ 11,980	$ 11,980	$ 11,980	$ 12,480	$ 12,480	$ 12,480	$ 12,480
29	Add: Issuances	-	-	-	-	475	-	-	500	-	-	-	-
30	Less: Retirements	-	-	-	-	-	-	-	-	-	-	-	-
31	Subtotal	$ 11,505	$ 11,505	$ 11,505	$ 11,505	$ 11,980	$ 11,980	$ 11,980	$ 12,480	$ 12,480	$ 12,480	$ 12,480	$ 12,480
32													
33	Less: Unamortized Fees	(114)	(114)	(114)	(113)	(117)	(117)	(117)	(121)	(121)	(121)	(120)	(120)
34													
35	Ending Balance	$ 11,391	$ 11,391	$ 11,391	$ 11,392	$ 11,863	$ 11,863	$ 11,863	$ 12,359	$ 12,359	$ 12,359	$ 12,360	$ 12,360
36													
37													
38													
39	Long-Term Debt	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26		
40													
41	Beginning Balance	$ 12,480	$ 12,480	$ 12,480	$ 12,480	$ 12,480	$ 12,890	$ 12,890	$ 12,890	$ 13,315	$ 13,315		
42	Add: Issuances	-	-	-	-	525	-	-	425	-	-		
43	Less: Retirements	-	-	-	-	(115)	-	-	-	-	-		
44	Subtotal	$ 12,480	$ 12,480	$ 12,480	$ 12,480	$ 12,890	$ 12,890	$ 12,890	$ 13,315	$ 13,315	$ 13,315		
45													
46	Less: Unamortized Fees	(120)	(119)	(119)	(119)	(124)	(124)	(124)	(126)	(126)	(126)		
47													
48	Ending Balance	$ 12,360	$ 12,361	$ 12,361	$ 12,361	$ 12,766	$ 12,766	$ 12,766	$ 13,189	$ 13,189	$ 13,189		
49													
50	**Test Year 13-Month Average:**												
51	Subtotal										$ 12,767		
52	Less: Unamortized Fees										(122)		
53	Ending Balance										**$ 12,645**		

Schedule D-1a

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Structure Development - Projected Common Equity Balance
for the Projected Year Ending October 31, 2026
(in millions)

Case No.: U-21806
Exhibit No.: A-14 (MRB-2)
Schedule: D-1a
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Witness: MRBleckman
Date: December 2024

Line No.	(a) Common Equity	(b) Actual Jan-23	(c) Actual Feb-23	(d) Actual Mar-23	(e) Actual Apr-23	(f) Actual May-23	(g) Actual Jun-23	(h) Actual Jul-23	(i) Actual Aug-23	(j) Actual Sep-23	(k) Actual Oct-23	(l) Actual Nov-23	(m) Actual Dec-23
1													
2	Beginning Balance	$10,134	$10,226	$10,059	$10,154	$10,181	$10,643	$10,702	$10,633	$10,668	$10,724	$10,556	$10,654
3	Ret. Earnings	92	(242)	95	27	62	59	(69)	35	56	(168)	98	125
4	Equity Infusion	-	75	-	-	400	-	-	-	-	-	-	-
5	Ending Balance	$ 10,226	$ 10,059	$ 10,154	$ 10,181	$ 10,643	$ 10,702	$ 10,633	$ 10,668	$ 10,724	$ 10,556	$ 10,654	$ 10,779
6													
7													
8													
9	Common Equity	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
10													
11	Beginning Balance	$10,779	$10,898	$10,712	$10,788	$10,790	$10,848	$10,872	$10,796	$10,885	$10,960	$10,792	$11,190
12	Ret. Earnings	119	(186)	76	2	58	24	(76)	89	75	(168)	98	125
13	Equity Infusion	-	-	-	-	-	-	-	-	-	-	300	115
14	Ending Balance	$ 10,898	$ 10,712	$ 10,788	$ 10,790	$ 10,848	$ 10,872	$ 10,796	$ 10,885	$ 10,960	$ 10,792	$ 11,190	$ 11,429
15													
16													
17													
18	Common Equity	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
19													
20	Beginning Balance	$11,429	$11,444	$11,908	$11,923	$11,937	$11,951	$12,441	$12,455	$12,470	$12,484	$12,498	$12,513
21	Ret. Earnings	14	14	14	14	14	14	14	14	14	14	14	14
22	Equity Infusion	-	450	-	-	-	475	-	-	-	-	-	-
23	Ending Balance	$ 11,444	$ 11,908	$ 11,923	$ 11,937	$ 11,951	$ 12,441	$ 12,455	$ 12,470	$ 12,484	$ 12,498	$ 12,513	$ 12,527
24													
25													
26													
27	Common Equity	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26		
28													
29	Beginning Balance	$12,527	$12,542	$13,006	$13,021	$13,035	$13,049	$13,514	$13,528	$13,543	$13,557		
30	Ret. Earnings	14	14	14	14	14	14	14	14	14	14		
31	Equity Infusion	-	450	-	-	-	450	-	-	-	-		
32	Ending Balance	$ 12,542	$ 13,006	$ 13,021	$ 13,035	$ 13,049	$ 13,514	$ 13,528	$ 13,543	$ 13,557	$ 13,571		
33													
34													
35	**Test Year 13-Month Average**										**$ 13,070**		

(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Test Year Impact of Retained Earnings			Test Year Impact of Equity Infusions		
	2024	**2025**	**2026**	**2024**	**2025**	**2026**
Jan	$ 119	$ 250	$ 423	$ -	$ 415	$ 1,340
Feb	$ (67)	$ 264	$ 437	$ -	$ 865	$ 1,790
Mar	$ 9	$ 279	$ 452	$ -	$ 865	$ 1,790
Apr	$ 11	$ 293	$ 466	$ -	$ 865	$ 1,790
May	$ 69	$ 308	$ 481	$ -	$ 865	$ 1,790
Jun	$ 93	$ 322	$ 495	$ -	$ 1,340	$ 2,240
Jul	$ 17	$ 336	$ 509	$ -	$ 1,340	$ 2,240
Aug	$ 106	$ 351	$ 524	$ -	$ 1,340	$ 2,240
Sep	$ 181	$ 365	$ 538	$ -	$ 1,340	$ 2,240
Oct	$ 13	$ 380	$ 553	$ -	$ 1,340	$ 2,240
Nov	$ 111	$ 394		$ 300	$ 1,340	
Dec	$ 236	$ 409		$ 415	$ 1,340	
13-Month Avg.			$ 466			$ 1,825

Schedule D-1a

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Structure Development - Projected Deferred Income Tax Balance
for the Projected Year Ending October 31, 2026
(in millions)

Case No.: U-21806
Exhibit No.: A-14 (MRB-2)
Schedule: D-1a
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Witness: MRBleckman
Date: December 2024

Deferred Income Tax Ending Balance

Line No.	(a) Actual Jan-23	(b) Actual Feb-23	(c) Actual Mar-23	(d) Actual Apr-23	(e) Actual May-23	(f) Actual Jun-23	(g) Actual Jul-23	(h) Actual Aug-23	(i) Actual Sep-23	(j) Actual Oct-23	(k) Actual Nov-23	(l) Actual Dec-23
1	$ 3,956	$ 3,973	$ 3,986	$ 3,998	$ 4,012	$ 4,045	$ 4,044	$ 4,045	$ 4,077	$ 4,067	$ 4,071	$ 4,103
2												
3												
4												
5	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
6	$ 4,116	$ 4,129	$ 4,142	$ 4,155	$ 4,169	$ 4,182	$ 4,195	$ 4,208	$ 4,221	$ 4,234	$ 4,247	$ 4,260
7												
8												
9												
10	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
11	$ 4,284	$ 4,307	$ 4,331	$ 4,354	$ 4,377	$ 4,401	$ 4,424	$ 4,447	$ 4,471	$ 4,494	$ 4,517	$ 4,541
12												
13												
14												
15	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26		
16	$ 4,563	$ 4,585	$ 4,607	$ 4,630	$ 4,652	$ 4,674	$ 4,696	$ 4,718	$ 4,741	$ 4,763		
17												
18												
19	**Test Year 13-Month Avg**									**$ 4,629**		

Schedule D-1b

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Development of Capital Structure
for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-14 (MRB-3)
Schedule: D-1b
Page: 1 of 1
Witness: MRBleckman
Date: December 2024

Line No.	(a) Description	(b) Financial Basis	(c) MPSC Ratemaking Basis
I.	LONG-TERM DEBT:		
a.	First Mortgage Bonds	Include	Include
b.	Trust Preferred Securities	Include	Include
c.	Other Subordinated LTD	Include	Include
d.	Unamortized Debt Premium	Include	Include
e.	Unamortized Debt Discount	Include	Include
f.	Unamortized Debt Expense	Include	Include
g.	Current Maturities	**Exclude**	**Include**
h.	Capitalized Leases	**Include**	**Exclude**
II.	SHORT-TERM DEBT	Include	Include
III.	PREFERRED STOCK EXPENSE		
a.	Preferred Stock	Include	Include
b.	Trust Preferred Securities	Exclude	Exclude
c.	Preferred Stock Expense	Include	Include
IV.	COMMON EQUITY		
a.	Common Stock Issued	Include	Include
b.	Premium on Common Stock	Include	Include
c.	Donations Received From Stockholders	Include	Include
d.	Common Stock Expense	Include	Include
e.	Gain on Reacquired Stock	Include	Include
f.	Miscellaneous Paid In Capital	Include	Include
g.	Mark-to-Market Accounting	**Include**	**Exclude**
h.	Appropriated Retained Earnings	Include	Include
I.	Unappropriated Retained Earnings	Include	Include
j.	FAS 90 (Abandoned Plant)	Include	Include
V.	DEFERRED ITC	**Exclude**	**Include**
VI.	DEFERRED TAXES	**Exclude**	**Include**
VII.	DEFERRED JDITC	**Exclude**	**Include**

Schedule D-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Long-Term Debt
for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-14 (MRB-4)
Schedule: D-2
Page: 1 of 1
Witness: MRBleckman
Date: December 2024

Line No.	(a) Description	(b) Original Issue Date	(c) Stated Maturity Date	(d) Interest Rate (%)	(d1) Interest Payments Per Year	(e) Amount of Offering ($000)	(f) Price to Public (%)	(g) Underwriting Expenses (%)	(g1) Underwriting Expenses ($000)	(g2) Financing Expenses (%)	(g3) Financing Expenses ($000)	(g4) (Premium) Discount ($000)	(h) Net Proceeds to the Company (%)	(i) Cost Based on Net Proceeds (%)	(j) Amount Outstanding ($000)	(k) Annual Cost ($000)
1																
2	**Mortgage Bonds**															
3	5.800%	11-Aug-05	15-Sep-35	5.800%	2	175,000	99.81%	0.875%	1,531.25	0.17%	299.97	337.75	98.761%	5.8879%	175,000	10,304
4	6.170%	01-Sep-10	01-Sep-40	6.170%	2	50,000	100.00%	0.906%	453.04	0.08%	38.99	0.00	99.016%	6.2430%	50,000	3,121
5	4.970%	15-Oct-10	15-Oct-40	4.970%	2	50,000	100.00%	0.500%	250.00	0.04%	19.58	0.00	99.461%	5.0049%	50,000	2,502
6	3.390%	17-Dec-12	15-Dec-27	3.390%	2	35,500	100.00%	0.501%	178.03	0.04%	13.76	0.00	99.460%	3.4364%	35,500	1,220
7	4.310%	17-Dec-12	15-Dec-42	4.310%	2	263,000	100.00%	0.501%	1,318.92	0.03%	68.78	0.00	99.472%	4.3416%	263,000	11,418
8	3.950%	17-May-13	15-May-43	3.950%	2	425,000	99.84%	0.875%	3,718.75	0.16%	675.43	667.25	98.809%	4.0187%	425,000	17,079
9	4.350%	18-Aug-14	31-Aug-64	4.350%	2	250,000	99.14%	0.875%	2,187.50	0.12%	309.64	2,157.50	98.138%	4.4430%	250,000	11,107
10	4.100%	06-Nov-15	15-Nov-45	4.100%	2	250,000	99.91%	0.875%	2,187.50	0.18%	447.46	217.50	98.859%	4.1669%	250,000	10,417
11	3.250%	10-Aug-16	15-Aug-46	3.250%	2	450,000	99.22%	0.875%	3,937.50	0.18%	821.46	3,501.00	98.164%	3.3474%	450,000	15,063
12	3.950%	22-Feb-17	15-Jul-47	3.950%	2	350,000	99.58%	0.875%	3,062.50	0.19%	669.34	1,463.00	98.516%	4.0350%	350,000	14,122
13	3.18% (Private Placement)	28-Sep-17	28-Sep-32	3.180%	2	40,000	100.00%	0.301%	120.48	0.03%	12.80	0.00	99.667%	3.2082%	40,000	1,283
14	3.52% (Private Placement)	28-Sep-17	28-Sep-37	3.520%	2	125,000	100.00%	0.402%	501.98	0.04%	53.33	0.00	99.556%	3.5512%	125,000	4,439
15	3.86% (Private Placement)	28-Sep-17	28-Sep-52	3.860%	2	20,000	100.00%	0.703%	140.56	0.07%	14.93	0.00	99.223%	3.9009%	20,000	780
16	3.18% (Private Placement)	15-Nov-17	15-Nov-32	3.180%	2	60,000	100.00%	0.301%	180.71	0.03%	18.60	0.00	99.668%	3.2081%	60,000	1,925
17	3.52% (Private Placement)	15-Nov-17	15-Nov-37	3.520%	2	210,000	100.00%	0.402%	843.33	0.04%	86.81	0.00	99.557%	3.5511%	210,000	7,457
18	3.86% (Private Placement)	15-Nov-17	15-Nov-52	3.860%	2	30,000	100.00%	0.703%	210.83	0.07%	21.70	0.00	99.225%	3.9008%	30,000	1,170
19	4.050%	14-May-18	15-May-48	4.050%	2	550,000	98.97%	0.875%	4,812.50	0.20%	1,106.61	5,659.50	97.895%	4.1737%	550,000	22,955
20	3.68% (Private Placement)	01-Oct-18	01-Oct-27	3.680%	2	100,000	100.00%	0.145%	145.00	0.01%	13.99	0.00	99.841%	3.7009%	100,000	3,701
21	4.01% (Private Placement)	01-Oct-18	01-Oct-38	4.010%	2	215,000	100.00%	0.323%	694.00	0.03%	56.32	0.00	99.651%	4.0356%	215,000	8,677
22	4.28% (Private Placement)	01-Oct-18	01-Oct-57	4.280%	2	185,000	100.00%	0.629%	1,164.00	0.05%	87.47	0.00	99.324%	4.3160%	185,000	7,985
23	3.800%	13-Nov-18	15-Nov-28	3.800%	2	300,000	99.75%	0.650%	1,950.00	0.10%	305.05	744.00	99.000%	3.9217%	300,000	11,765
24	4.350%	13-Nov-18	15-Apr-49	4.350%	2	550,000	99.62%	0.875%	4,812.50	0.18%	985.10	2,101.00	98.564%	4.4363%	550,000	24,400
25	3.750%	28-May-19	15-Feb-50	3.750%	2	300,000	98.83%	0.875%	2,625.00	0.21%	632.06	3,498.00	97.748%	3.8758%	300,000	11,627
26	3.100%	03-Sep-19	15-Aug-50	3.100%	2	550,000	99.29%	0.875%	4,812.50	0.10%	526.98	3,899.50	98.320%	3.1857%	550,000	17,521
27	Floating Rate FMB	19-Sep-19	15-Sep-69	3.060%	4	75,649	100.00%	1.000%	756.49	0.99%	751.55	0.00	98.007%	3.1392%	75,649	2,375
28	3.500%	26-Mar-20	01-Aug-51	3.500%	2	575,000	100.00%	0.875%	5,031.25	0.22%	1,261.45	0.00	98.906%	3.5580%	575,000	20,459
29	2.500%	13-May-20	01-May-60	2.500%	2	525,000	100.00%	0.875%	4,593.75	0.17%	905.40	0.00	98.953%	2.5419%	525,000	13,345
30	Floating Rate FMB	20-May-20	20-May-70	3.060%	4	134,349	100.00%	1.000%	1,343.49	0.29%	390.52	0.00	98.709%	3.1110%	134,349	4,180
31	Floating Rate FMB	07-Oct-20	07-Oct-70	3.060%	4	126,497	100.00%	1.000%	1,264.97	0.25%	315.63	0.00	98.750%	3.1093%	126,497	3,933
32	2.650%	02-Aug-21	15-Aug-52	2.650%	2	300,000	99.92%	0.875%	2,625.00	0.19%	569.00	252.00	98.851%	2.7049%	300,000	8,115
33	3.600%	11-Aug-22	15-Aug-32	3.600%	2	350,000	99.93%	0.650%	2,275.00	0.20%	700.00	262.50	99.075%	3.7114%	350,000	12,990
34	4.200%	11-Aug-22	01-Sep-52	4.200%	2	450,000	99.93%	0.875%	3,937.50	0.20%	900.00	319.50	98.854%	4.2679%	450,000	19,206
35	4.650%	10-Jan-23	01-Mar-28	4.650%	2	425,000	99.81%	0.600%	2,550.00	0.20%	850.00	790.50	99.014%	4.8680%	425,000	20,689
36	4.625%	23-Feb-23	15-May-33	4.625%	2	700,000	100.00%	0.650%	4,550.00	0.20%	1,400.00	0.00	99.150%	4.7300%	700,000	33,110
37	5.24% (Private Placement)	15-May-23	15-May-26	5.240%	2	115,000	100.00%	0.875%	1,006.25	0.20%	230.00	0.00	98.925%	5.6345%	61,923	3,489
38	5.07% (Private Placement)	15-May-23	15-May-29	5.070%	2	50,000	100.00%	0.875%	437.50	0.20%	100.00	0.00	98.925%	5.2814%	50,000	2,641
39	5.17% (Private Placement)	15-May-23	15-May-32	5.170%	2	95,000	100.00%	0.875%	831.25	0.20%	190.00	0.00	98.925%	5.3219%	95,000	5,056
40	5.38% (Private Placement)	15-May-23	15-May-37	5.380%	2	140,000	100.00%	0.875%	1,225.00	0.20%	280.00	0.00	98.925%	5.4910%	140,000	7,687
41	4.900%	04-Aug-23	15-Feb-29	4.900%	2	500,000	99.95%	0.600%	3,000.00	0.12%	582.56	250.00	99.233%	5.0603%	500,000	25,301
42	4.600%	09-Jan-24	30-May-29	4.600%	2	600,000	99.77%	0.600%	3,600.00	0.10%	625.48	1,392.00	99.064%	4.7982%	600,000	28,789
43	4.700%	05-Aug-24	15-Jan-30	4.700%	2	700,000	99.78%	0.600%	4,200.00	0.11%	782.00	1,575.00	99.063%	4.8975%	700,000	34,283
44	New Debt Issue #1	01-May-25	01-May-55	5.660%	2	475,000	100.00%	0.875%	4,156.25	0.20%	950.00	0.00	98.925%	5.7355%	475,000	27,244
45	New Debt Issue #2	01-Aug-25	01-Aug-55	5.660%	2	500,000	100.00%	0.875%	4,375.00	0.20%	1,000.00	0.00	98.925%	5.7355%	500,000	28,677
46	New Debt Issue #3	01-May-26	02-May-56	5.670%	2	525,000	100.00%	0.875%	4,593.75	0.20%	1,050.00	0.00	98.925%	5.7456%	242,308	13,922
47	New Debt Issue #4	01-Aug-26	01-Aug-56	5.670%	2	425,000	100.00%	0.875%	3,718.75	0.20%	850.00	0.00	98.925%	5.7456%	98,077	5,635
48	Total Mortgage Bonds														$12,657,303	$ 543,166
49																
50	**Other Long-Term Debt**															
51	PCRB - MSF LORB - 19	01-Oct-19	01-Oct-49	3.350%	2	75,000	100.00%	0.592%	443.75	0.89%	669.74	0.00	98.515%	3.4296%	$ 75,000	$ 2,572
52	PCRB - MSF LORB - 21	07-Oct-21	01-Apr-35	0.875%	2	35,000	100.00%	0.600%	210.00	0.90%	315.00	0.00	98.500%	0.9941%	35,000	348
53															$ 110,000	$ 2,920
54																
55																
56	Total Long-Term Debt														$12,767,303	$ 546,086
57																
58	Amortization of Losses on Reacquired Debt with Refunding (including Call Premiums)															4,305
59																
60	Total Long-Term Debt Before Unamortized Expense and Premium													4.31%	$12,767,303	$ 550,391
61																
62	Unamortized Debt Discount, Expense and Premium														(122,154)	
63																
64	Total Long-Term Debt Balance														$12,645,149	
65																
66	Annual Cost													4.35%		
67																

Ties to 13-Month Average in Exhibit A-14 (MRB-2), Schedule D-1a, pg. 2

68 **Calculations:**
69 Column (i) = Yield formula based on inputs from column (b),column (c), column (d), column (d1), and column (h) calculated on an annualized basis.
70 Column (j) = Represents the average amount of debt outstanding for the test year.
71 Column (k) = column (i)*column (j).
72 Lines 27, 30, and 31 Coupon Rate = Projected SOFR Rate of 3.36% minus 0.30%.
73 Lines 37, 46, and 47 - As this is a partial year debt outstanding, pro-rata balance and pro-rata interest expense are used which would result
74 in the same cost rate as an annual analysis, but provides a more accurate average debt balance for the Test Year. This would make
75 the Total Debt balance line 64 tie to the debt balance shown on Exhibit A-14 (MRB-2), Schedule D-1a, page 2.
76 Line 58 - Amortization of losses on reacquired debt projected for the test year ending October 31, 2026.
77
78 Projected SOFR Rate — Test Year Avg.
79
80 Bloomberg (Oct. 24, 2024) 3.36%

Projected New Debt Issue Interest Rates	New Debt #1 May 2025	New Debt #2 Aug. 2025	New Debt #3 May 2026	New Debt #4 Aug. 2026
Projected 30-Yr Treasury Rate (Bloomberg)	4.30%	4.30%	4.31%	4.31%
Add: Historical 30-Year Bond Spread	1.36%	1.36%	1.36%	1.36%
	5.66%	**5.66%**	**5.67%**	**5.67%**

Schedule D-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Short-Term Debt
for the Projected Year Ending October 31, 2026
(in millions)

Case No.: U-21806
Exhibit No.: A-14 (MRB-5)
Schedule: D-3
Page: 1 of 2
Witness: MRBleckman
Date: December 2024

Line No.		(a) **Average Borrowings**	(b) **Cost of Borrowings**	(c) **Cost Rate**
1	Short-Term Debt	$ 201.4	$ 9.1	4.52%

Sources:
Column (a): Exhibit A-14 (MRB-7), Schedule D-6.
Column (b): Exhibit A-14 (MRB-5), Schedule D-3, page 2.
Column (c) = column (b)/column (a).

Schedule D-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Short-Term Debt
for the Projected Year Ending October 31, 2026
(in millions)

Case No.: U-21806
Exhibit No.: A-14 (MRB-5)
Schedule: D-3
Page: 2 of 2
Witness: MRBleckman
Date: December 2024

Summary

Line No.	Facility	Agreement Date	Expiration	Facility Amount	Test Year Assumption: Less: Avg. Borrowings (A)	Less: Letters of Credit (B)	Amount Unused[a] (C)	Upfront Fee Amort (D)
4	1. JPMorgan Revolver	Jun. 2018	Dec. 2027	$ 1,100.0	$ -	$ 28.1	$ 1,071.9	$ 0.4
5	2. Commercial Paper Facility	Sep. 2014	N/A	$ 500.0	$ 201.4	$ -	$ -	$ -
6	3. Scotiabank Revolver	Nov. 2018	Nov. 2025	$ 250.0	$ -	$ 56.7	$ 193.3	$ 0.3

Cost of Short-Term Debt

(A) **Interest on Borrowings** - Calculated on the projected drawn balance at SOFR plus the spread on borrowings.

Facility	SOFR[b]	Plus: Spread	Projected Rate	Avg. Borrowings	Cost
1. JPMorgan Revolver	3.36%	0.850%	4.21%	$ -	$ -
2. Commercial Paper Facility	3.36%	0.000%	3.36%	201.4	6.8
3. Scotiabank Revolver	3.36%	0.800%	4.16%	-	-
					$ 6.8

(B) **Letter of Credit Fees** - Calculated on the projected letters of credit outstanding at a rate equal to the spread.

Facility	Letter of Credit Type	Projected Rate	Letters of Credit	Cost
1. JPMorgan Revolver	Regular Operating	0.850%	$ 28.1	$ 0.2
2. Commercial Paper Facility	N/A	N/A	-	-
3. Scotiabank Revolver	MISO Margin & Other	0.800%	56.7	0.5
				$ 0.7

(C) **Unused (Commitment) Fees** - Calculated on the unused portion of the revolver at a rate stated in the facility agreement.

	Projected Rate	Amount Unused[a]	Cost
1. JPMorgan Revolver	0.070%	$ 1,071.9	$ 0.8
2. Commercial Paper Facility	N/A	-	-
3. Scotiabank Revolver	0.075%	$ 193.3	$ 0.1
			$ 0.9

(D) **Amortization / Expense of Facility Fees** - Fees paid upfront at the inception or amendment to the facility, amortized over the life of the facility.

	Annual Cost
1. JPMorgan Revolver	$ 0.4
2. Commercial Paper Facility	-
3. Scotiabank Revolver	0.3
	$ 0.7

Total Cost of Short-Term Debt **$ 9.1**

[a] Commercial Paper drawn balances go against, or are "backstopped," by the Company's JPMorgan Revolver. To the extent amounts are borrowed under the Commercial Paper Facility, the availability of the JPMorgan Revolver are reduced. These borrowings do not, however, reduce the "unused" portion of the revolver in calculating the unused (commitment) fees.

[b] Projected SOFR rate per Exhibit A-14 (MRB-4), Schedule D-2. Forecasted SOFR assumed to closely approximate commercial paper rate.

Schedule D-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cost of Preferred Stock
for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-14 (MRB-6)
Schedule: D-4
Page: 1 of 1
Witness: MRBleckman
Date: December 2024

Line No.	(a) Description	(b) Annual Dividend	(c) Par Value	(d) Finance Expense	(e) (Premium) Discount	(f) Net Proceeds Received By Company	(g) Number Of Shares Outstanding	(h) Total Value Of Net Proceeds (000)	(i) Cost Rates	(j) Annual Cost (000)
	PREFERRED STOCK:									
1	$4.500 Series	$4.500	$100.00	$0.00	$0.00	$100.00	373,148	$37,315	4.50%	$1,679

Calculations:
Column (i) = (column (h)*column (b)/column (f))/column (h).
Column (j) = column (h)*column (i).

Schedule D-6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Short-Term Debt Utilization
for the Projected Year Ending October 31, 2026
(in millions)

Case No.: U-21806
Exhibit No.: A-14 (MRB-7)
Schedule: D-6
Page: 1 of 1
Witness: MRBleckman
Date: December 2024

Ending Short-Term Debt

Line No.	(a) Actual Jan-23	(b) Actual Feb-23	(c) Actual Mar-23	(d) Actual Apr-23	(e) Actual May-23	(f) Actual Jun-23	(g) Actual Jul-23	(h) Actual Aug-23	(i) Actual Sep-23	(j) Actual Oct-23	(k) Actual Nov-23	(l) Actual Dec-23
1												
2	$ 500	$ 19	$ -	$ -	$ -	$ -	$ 24	$ 85	$ 310	$ 420	$ 704	$ 93
3												
4												
5	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
6												
7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13	$ 203	$ 303
8												
9												
10	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
11												
12	$ 194	$ 15	$ -	$ -	$ -	$ -	$ -	$ 80	$ 345	$ 385	$ 490	$ 475
13												
14												
15	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26		
16												
17	$ 255	$ 145	$ -	$ -	$ -	$ -	$ -	$ 98	$ 320	$ 450		
18												
19	**Test Year 13-Month Avg**									**$ 201**		

Schedule E-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Market Outlook: 5-Year Annual Calendar Gas Forecast by Class
(Consumption in MMcf)

Case No.: U-21806
Exhibit No.: A-15 (MA-5)
Schedule: E-1
Page: 1 of 1
Witness: MAhmed
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
							LAUF Gas Volumes		
Line	Year	Residential	Commercial	Industrial	Inter-departmental	Total	MMcf	% of Output	Sendout
1	2025 Fcst	159,295	82,771	65,464	596	308,126	3,856 (2)	1.3	311,982
2	2026 Fcst	159,121	82,683	65,185	595	307,583	3,856	1.3	311,439
3	2027 Fcst	158,933	82,566	64,953	591	307,043	3,856	1.3	310,899
4	2028 Fcst	158,765	82,268	64,654	586	306,273	3,856	1.3	310,129
5	2029 Fcst	158,723	81,980	64,543	581	305,827	3,856	1.3	309,684
6	CAGR (25 - 29)	-0.1%	-0.2%	-0.4%	-0.6%	-0.2%	0.0%		-0.2%

Notes
(1) CAGR - Compound Annual Growth Rates
(2) Exhibit A-75 (TKJ-4), line 14, column (f)

Schedule E-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test-Year Cycle Gas Deliveries Forecast by Class
15-Year (2009 - 2023) Weather Normal
(Consumption in MMcf)

Case No.: U-21806
Exhibit No.: A-15 (MA-6)
Schedule: E-2
Page: 1 of 1
Witness: MAhmed
Date: December 2024

Line	(a) Service	(b) Mth/Yr	(c) Residential	(d) Commercial	(e) Industrial	(f) Inter-departmental	(g) Total
1	Deliveries	Nov-25	11,205	5,738	5,414	16	22,373
2	Deliveries	Dec-25	20,295	9,682	6,470	20	36,467
3	Deliveries	Jan-26	28,243	13,057	6,629	53	47,982
4	Deliveries	Feb-26	27,961	13,499	7,256	27	48,743
5	Deliveries	Mar-26	24,610	11,864	6,606	19	43,099
6	Deliveries	Apr-26	17,547	9,002	6,459	20	33,028
7	Deliveries	May-26	10,474	5,757	4,994	19	21,244
8	Deliveries	Jun-26	5,015	3,408	4,188	9	12,620
9	Deliveries	Jul-26	3,105	2,556	4,027	83	9,771
10	Deliveries	Aug-26	2,773	2,470	4,159	111	9,513
11	Deliveries	Sep-26	3,091	2,559	4,521	175	10,346
12	Deliveries	Oct-26	4,853	3,132	4,521	43	12,549
13	Deliveries	Annual	159,172	82,725	65,244	595	307,736
14	Sales	Nov-25	11,128	3,910	507	16	15,561
15	Sales	Dec-25	20,154	7,167	987	20	28,328
16	Sales	Jan-26	28,051	10,042	1,381	23	39,497
17	Sales	Feb-26	27,718	10,000	1,431	18	39,167
18	Sales	Mar-26	24,401	8,793	1,279	19	34,492
19	Sales	Apr-26	17,368	6,246	908	20	24,542
20	Sales	May-26	10,348	3,718	518	19	14,603
21	Sales	Jun-26	4,949	1,932	263	9	7,153
22	Sales	Jul-26	3,071	1,373	183	10	4,637
23	Sales	Aug-26	2,743	1,295	184	11	4,233
24	Sales	Sep-26	3,060	1,357	194	34	4,645
25	Sales	Oct-26	4,818	1,843	252	11	6,924
26	Sales	Annual	157,809	57,677	8,087	210	223,783
27	Transport	Nov-25	77	1,828	4,907	-	6,812
28	Transport	Dec-25	141	2,515	5,483	-	8,139
29	Transport	Jan-26	192	3,015	5,248	30	8,485
30	Transport	Feb-26	243	3,499	5,825	9	9,576
31	Transport	Mar-26	209	3,071	5,327	-	8,607
32	Transport	Apr-26	179	2,756	5,551	-	8,486
33	Transport	May-26	126	2,039	4,476	-	6,641
34	Transport	Jun-26	66	1,476	3,925	-	5,467
35	Transport	Jul-26	34	1,183	3,844	73	5,134
36	Transport	Aug-26	30	1,175	3,975	100	5,280
37	Transport	Sep-26	31	1,202	4,327	141	5,701
38	Transport	Oct-26	35	1,289	4,269	32	5,625
39	Transport	Annual	1,363	25,048	57,157	385	83,953

Schedule E-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test-Year Cycle Gas Deliveries by Rate Schedule
15-Year (2009 - 2023) Weather Normal
(Consumption in MMcf)

Case No.: U-21806
Exhibit No.: A-15 (MA-7)
Schedule: E-3
Page: 1 of 1
Witness: MAhmed
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		TOTAL DELIVERIES										
		Residential		**General Service**				**Transportation**				
Line	**Month**	**A**	**A-1**	**GS-1**	**GS-2**	**GS-3**	**GL**	**ST**	**LT**	**XLT**	**XXLT**	**Total**
1	Nov-25	10,677	460	1,944	2,072	588	-	1,450	1,573	2,196	1,412	22,373
2	Dec-25	19,437	732	3,767	3,722	972	-	1,986	1,737	2,617	1,497	36,467
3	Jan-26	27,058	1,015	5,430	5,213	1,216	-	2,061	1,923	2,978	1,087	47,982
4	Feb-26	26,801	941	5,408	5,206	1,257	-	2,551	2,260	3,226	1,094	48,743
5	Mar-26	23,527	895	4,674	4,644	1,128	-	2,166	2,072	2,933	1,058	43,099
6	Apr-26	16,729	660	3,226	3,363	904	-	1,906	1,879	2,902	1,459	33,028
7	May-26	9,896	462	1,881	1,950	571	-	1,571	1,622	1,961	1,328	21,244
8	Jun-26	4,706	247	919	1,008	345	-	1,158	1,208	1,835	1,193	12,620
9	Jul-26	2,911	163	633	701	268	-	933	1,187	1,587	1,388	9,771
10	Aug-26	2,599	146	597	639	285	-	907	1,087	1,522	1,731	9,513
11	Sep-26	2,905	158	626	690	306	-	1,014	1,224	1,653	1,771	10,346
12	Oct-26	4,573	249	842	992	343	-	977	1,198	1,867	1,509	12,549
13	Annual	151,820	6,130	29,949	30,200	8,183	-	18,679	18,970	27,277	16,528	307,736
		27,058	1,015	5,430	5,213	1,257	-	2,551	2,260	3,226	1,771	48,743
		SALES										
		Residential		**General Service**				**Transportation**				
Line	**Month**	**A**	**A-1**	**GS-1**	**GS-2**	**GS-3**	**GL**	**ST**	**LT**	**XLT**	**XXLT**	**Total**
14	Nov-25	10,676	451	1,930	1,927	576	-	-	-	-	-	15,561
15	Dec-25	19,436	718	3,743	3,475	956	-	-	-	-	-	28,328
16	Jan-26	27,056	995	5,395	4,858	1,193	-	-	-	-	-	39,497
17	Feb-26	26,799	919	5,373	4,843	1,233	-	-	-	-	-	39,167
18	Mar-26	23,525	875	4,645	4,340	1,106	-	-	-	-	-	34,492
19	Apr-26	16,727	641	3,199	3,091	884	-	-	-	-	-	24,542
20	May-26	9,895	453	1,870	1,824	560	-	-	-	-	-	14,603
21	Jun-26	4,706	243	914	951	339	-	-	-	-	-	7,153
22	Jul-26	2,911	160	631	672	263	-	-	-	-	-	4,637
23	Aug-26	2,599	144	594	615	281	-	-	-	-	-	4,233
24	Sep-26	2,904	156	622	662	301	-	-	-	-	-	4,645
25	Oct-26	4,573	246	835	936	336	-	-	-	-	-	6,924
26	Annual	151,808	6,001	29,752	28,195	8,028	-	-	-	-	-	223,783
		27,056	995	5,395	4,858	1,233	-	-	-	-	-	39,497
		TRANSPORTATION										
		Residential		**General Service**				**Transportation**				
Line	**Month**	**A**	**A-1**	**GS-1**	**GS-2**	**GS-3**	**GL**	**ST**	**LT**	**XLT**	**XXLT**	**Total**
27	Nov-25	0.649	9	14	146	12	-	1,450	1,573	2,196	1,412	6,812
28	Dec-25	1.313	14	24	247	16	-	1,986	1,737	2,617	1,497	8,139
29	Jan-26	1.966	21	36	355	23	-	2,061	1,923	2,978	1,087	8,485
30	Feb-26	2.230	22	36	362	23	-	2,551	2,260	3,226	1,094	9,576
31	Mar-26	2.100	20	29	304	22	-	2,166	2,072	2,933	1,058	8,607
32	Apr-26	1.881	19	26	272	20	-	1,906	1,879	2,902	1,459	8,486
33	May-26	1.041	9	11	126	11	-	1,571	1,622	1,961	1,328	6,641
34	Jun-26	0.327	4	5	57	6	-	1,158	1,208	1,835	1,193	5,467
35	Jul-26	0.177	3	3	28	5	-	933	1,187	1,587	1,388	5,134
36	Aug-26	0.154	3	2	24	5	-	907	1,087	1,522	1,731	5,280
37	Sep-26	0.189	3	4	27	6	-	1,014	1,224	1,653	1,771	5,701
38	Oct-26	0.306	4	7	56	7	-	977	1,198	1,867	1,509	5,625
39	Annual	12.333	129	197	2,005	155	-	18,679	18,970	27,277	16,528	83,953

Schedule E-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test-Year Authorized Tolerance Levels by Rate Schedule
(Consumption in MMcf)

Case No.: U-21806
Exhibit No.: A-15 (MA-8)
Schedule: E-4
Page: 1 of 1
Witness: MAhmed
Date: December 2024

Line	Description	(a) Nov-25	(b) Dec-25	(c) Jan-26	(d) Feb-26	(e) Mar-26	(f) Apr-26	(g) May-26	(h) Jun-26	(i) Jul-26	(j) Aug-26	(k) Sep-26	(l) Oct-26	(m) Annual
	Small Transport ST													
1	2% ATL	2	3	3	3	3	3	2	1	1	1	1	1	23
2	4% ATL	15	14	18	18	18	16	15	10	8	6	8	10	158
3	6.5% ATL	154	193	176	230	189	155	131	109	99	85	100	94	1,715
4	7.5% ATL	30	35	39	49	41	35	29	21	18	17	21	20	355
5	8.5% ATL	1,250	1,741	1,825	2,250	1,917	1,697	1,394	1,016	807	798	884	852	16,429
6	9.5% ATL	-	-	-	-	-	-	-	-	-	-	-	-	-
7	10.5% ATL	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Total ATL	1,450	1,986	2,061	2,551	2,166	1,906	1,571	1,158	933	907	1,014	977	18,679
	Large Transport LT													
9	2% ATL	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4% ATL	79	85	99	113	110	91	79	64	64	54	60	64	962
11	6.5% ATL	244	258	255	314	281	240	214	190	192	195	197	189	2,771
12	7.5% ATL	14	19	23	27	23	20	17	12	9	9	10	10	193
13	8.5% ATL	1,235	1,376	1,545	1,805	1,658	1,527	1,312	942	922	829	958	935	15,044
14	9.5% ATL	-	-	-	-	-	-	-	-	-	-	-	-	-
15	10.5% ATL	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Total ATL	1,573	1,737	1,923	2,260	2,072	1,879	1,622	1,208	1,187	1,087	1,224	1,198	18,970
	Extra-large Transport XLT													
17	2% ATL	506	487	544	505	511	519	188	144	71	52	78	362	3,967
18	4% ATL	125	171	178	173	169	179	141	122	143	149	141	148	1,839
19	6.5% ATL	1,076	1,287	1,467	1,695	1,469	1,501	1,084	862	893	820	875	896	13,925
20	7.5% ATL	61	94	89	97	80	67	82	90	94	97	103	96	1,049
21	8.5% ATL	428	578	699	757	705	636	467	617	386	404	456	365	6,497
22	9.5% ATL	-	-	-	-	-	-	-	-	-	-	-	-	-
23	10.5% ATL	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total ATL	2,196	2,617	2,978	3,226	2,933	2,902	1,961	1,835	1,587	1,522	1,653	1,867	27,277
	Extra-Extra-large Transport XXLT													
25	4% ATL	1,412	1,497	1,087	1,094	1,058	1,459	1,328	1,193	1,388	1,731	1,771	1,509	16,528
26	Total ATL	1,412	1,497	1,087	1,094	1,058	1,459	1,328	1,193	1,388	1,731	1,771	1,509	16,528

Schedule E-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Market Outlook: 5-Year Average Customer Forecast by Class
(Consumption in MMcf)

Case No.: U-21806
Exhibit No.: A-15 (MA-9)
Schedule: E-5
Page: 1 of 1
Witness: MAhmed
Date: December 2024

Line	(a) Year	(b) Residential	(c) Commercial	(d) Industrial	(e) Inter-departmental	(f) Total
1	2025 Fcst	1,702,287	132,739	4,144	58	1,839,228
2	2026 Fcst	1,711,096	133,107	4,144	58	1,848,406
3	2027 Fcst	1,719,748	133,436	4,144	58	1,857,387
4	2028 Fcst	1,728,302	133,737	4,144	58	1,866,241
5	2029 Fcst	1,736,316	134,019	4,144	58	1,874,538
6	CAGR (25 - 29)	0.50%	0.24%	0.00%	0.00%	0.48%

Notes
(1) CAGR - Compound Annual Growth Rates

Schedule E-6

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test-Year Customer Count Forecast by Class
Billed & Contiguous Customers
(Monthly Customer Counts)

Case No.: U-21806
Exhibit No.: A-15 (MA-10)
Schedule: E-6
Page: 1 of 1
Witness: MAhmed
Date: December 2024

Line	(a) Service	(b) Month	(c) Residential	(d) Commercial	(e) Industrial	(f) Inter-departmental	(g) Total
1	Deliveries	Nov-25	1,705,107	132,776	4,147	57	1,842,087
2	Deliveries	Dec-25	1,706,468	133,168	4,146	57	1,843,839
3	Deliveries	Jan-26	1,708,890	133,481	4,145	57	1,846,573
4	Deliveries	Feb-26	1,709,616	134,015	4,144	57	1,847,832
5	Deliveries	Mar-26	1,710,432	133,916	4,145	57	1,848,550
6	Deliveries	Apr-26	1,708,203	133,185	4,145	57	1,845,590
7	Deliveries	May-26	1,713,712	133,041	4,145	57	1,850,955
8	Deliveries	Jun-26	1,710,612	132,976	4,146	57	1,847,791
9	Deliveries	Jul-26	1,711,759	132,335	4,146	57	1,848,297
10	Deliveries	Aug-26	1,710,352	132,353	4,146	57	1,846,908
11	Deliveries	Sep-26	1,709,729	132,521	4,146	57	1,846,453
12	Deliveries	Oct-26	1,710,853	132,765	4,145	57	1,847,820
13	Deliveries	Annual	1,709,644	133,044	4,146	57	1,846,891
14	Sales	Nov-25	1,704,896	130,004	3,612	57	1,838,569
15	Sales	Dec-25	1,706,257	130,396	3,611	57	1,840,321
16	Sales	Jan-26	1,708,679	130,709	3,610	57	1,843,055
17	Sales	Feb-26	1,709,405	131,243	3,609	57	1,844,314
18	Sales	Mar-26	1,710,221	131,142	3,610	57	1,845,030
19	Sales	Apr-26	1,707,992	130,410	3,610	57	1,842,069
20	Sales	May-26	1,713,501	130,265	3,610	57	1,847,433
21	Sales	Jun-26	1,710,401	130,200	3,611	57	1,844,269
22	Sales	Jul-26	1,711,548	129,559	3,611	57	1,844,775
23	Sales	Aug-26	1,710,141	129,577	3,611	57	1,843,386
24	Sales	Sep-26	1,709,518	129,744	3,611	57	1,842,930
25	Sales	Oct-26	1,710,642	129,988	3,610	57	1,844,297
26	Sales	Annual	1,709,433	130,270	3,611	57	1,843,371
27	Transport	Nov-25	211	2,772	535	-	3,518
28	Transport	Dec-25	211	2,772	535	-	3,518
29	Transport	Jan-26	211	2,772	535	-	3,518
30	Transport	Feb-26	211	2,772	535	-	3,518
31	Transport	Mar-26	211	2,774	535	-	3,520
32	Transport	Apr-26	211	2,775	535	-	3,521
33	Transport	May-26	211	2,776	535	-	3,522
34	Transport	Jun-26	211	2,776	535	-	3,522
35	Transport	Jul-26	211	2,776	535	-	3,522
36	Transport	Aug-26	211	2,776	535	-	3,522
37	Transport	Sep-26	211	2,777	535	-	3,523
38	Transport	Oct-26	211	2,777	535	-	3,523
39	Transport	Annual	211	2,775	535	-	3,521

Schedule E-7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test-Year Total Customer Count Forecast by Rate Schedule
(Monthly Customer Counts)

Case No.: U-21806
Exhibit No.: A-15 (MA-11)
Schedule: E-7
Page: 1 of 1
Witness: MAhmed
Date: December 2024

TOTAL CUSTOMERS

Line	Month	Residential A	Residential A-1	General Service GS-1	General Service GS-2	General Service GS-3	General Service GL	Transportation ST	Transportation LT	Transportation XLT	Transportation XXLT	Total
1	Nov-25	1,695,844	9,214	118,322	16,369	568	-	1,281	358	128	3	1,842,087
2	Dec-25	1,697,198	9,221	118,815	16,270	565	-	1,281	358	128	3	1,843,839
3	Jan-26	1,699,607	9,234	119,240	16,163	559	-	1,281	358	128	3	1,846,573
4	Feb-26	1,700,329	9,238	119,862	16,079	554	-	1,281	358	128	3	1,847,832
5	Mar-26	1,701,140	9,243	119,920	15,928	548	-	1,281	359	128	3	1,848,550
6	Apr-26	1,698,923	9,231	119,408	15,715	541	-	1,282	359	128	3	1,845,590
7	May-26	1,704,403	9,260	119,423	15,562	535	-	1,282	359	128	3	1,850,955
8	Jun-26	1,701,319	9,244	119,509	15,417	530	-	1,282	359	128	3	1,847,791
9	Jul-26	1,702,460	9,250	119,076	15,216	523	-	1,282	359	128	3	1,848,297
10	Aug-26	1,701,061	9,242	119,238	15,077	518	-	1,282	359	128	3	1,846,908
11	Sep-26	1,700,441	9,239	119,533	14,954	513	-	1,282	359	129	3	1,846,453
12	Oct-26	1,701,559	9,245	119,895	14,840	508	-	1,282	359	129	3	1,847,820
13	Annual	20,404,284	110,861	1,432,241	187,590	6,462	-	15,379	4,304	1,538	36	22,162,695
14	Average	1,700,357	9,238	119,353	15,633	539	-	1,282	359	128	3	1,846,891

BILLED

Line	Month	Residential A	Residential A-1	General Service GS-1	General Service GS-2	General Service GS-3	General Service GL	Transportation ST	Transportation LT	Transportation XLT	Transportation XXLT	Total
15	Nov-25	1,695,844	9,214	118,296	16,311	511	-	669	100	24	3	1,840,972
16	Dec-25	1,697,198	9,221	118,788	16,212	508	-	669	100	24	3	1,842,723
17	Jan-26	1,699,607	9,234	119,213	16,105	504	-	669	100	24	3	1,845,459
18	Feb-26	1,700,329	9,238	119,834	16,020	500	-	669	100	24	3	1,846,717
19	Mar-26	1,701,140	9,243	119,891	15,869	495	-	669	101	24	3	1,847,435
20	Apr-26	1,698,923	9,231	119,379	15,656	489	-	669	101	24	3	1,844,475
21	May-26	1,704,403	9,260	119,393	15,503	484	-	669	101	24	3	1,849,840
22	Jun-26	1,701,319	9,244	119,478	15,358	479	-	669	101	24	3	1,846,675
23	Jul-26	1,702,460	9,250	119,045	15,157	474	-	669	101	24	3	1,847,183
24	Aug-26	1,701,061	9,242	119,206	15,018	469	-	669	101	24	3	1,845,793
25	Sep-26	1,700,441	9,239	119,501	14,896	465	-	669	101	24	3	1,845,339
26	Oct-26	1,701,559	9,245	119,862	14,781	461	-	669	101	24	3	1,846,705
27	Annual	20,404,284	110,861	1,431,886	186,886	5,839	-	8,028	1,208	288	36	22,149,316
28	Average	1,700,357	9,238	119,324	15,574	487	-	669	101	24	3	1,845,776

CONTIGUOUS

Line	Month	Residential A	Residential A-1	General Service GS-1	General Service GS-2	General Service GS-3	General Service GL	Transportation ST	Transportation LT	Transportation XLT	Transportation XXLT	Total
29	Nov-25	-	-	26	58	57	-	612	258	104	-	1,115
30	Dec-25	-	-	27	58	57	-	612	258	104	-	1,116
31	Jan-26	-	-	27	58	55	-	612	258	104	-	1,114
32	Feb-26	-	-	28	59	54	-	612	258	104	-	1,115
33	Mar-26	-	-	29	59	53	-	612	258	104	-	1,115
34	Apr-26	-	-	29	59	52	-	613	258	104	-	1,115
35	May-26	-	-	30	59	51	-	613	258	104	-	1,115
36	Jun-26	-	-	31	59	51	-	613	258	104	-	1,116
37	Jul-26	-	-	31	59	49	-	613	258	104	-	1,114
38	Aug-26	-	-	32	59	49	-	613	258	104	-	1,115
39	Sep-26	-	-	32	58	48	-	613	258	105	-	1,114
40	Oct-26	-	-	33	59	47	-	613	258	105	-	1,115
41	Annual	-	-	355	704	623	-	7,351	3,096	1,250	-	13,379
42	Average	-	-	30	59	52	-	613	258	104	-	1,115

Schedule E-8

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Test-Year Projected Income Assistance Enrollments
(Consumption in MMcf)

Case No.: U-21806
Exhibit No.: A-15 (MA-12)
Schedule: E-8
Page: 1 of 1
Witness: MAhmed
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Single Family Dwelling Rate Schedule A					
		Standard		**Income Assistance**		**Total**	
Line	**Month**	**Customers**	**Consumption**	**Customers**	**Consumption**	**Customers**	**Consumption**
1	Nov-25	1,609,075	10,130	86,769	546	1,695,844	10,676
2	Dec-25	1,610,360	18,441	86,838	994	1,697,198	19,436
3	Jan-26	1,612,645	25,672	86,962	1,384	1,699,607	27,056
4	Feb-26	1,613,330	25,427	86,999	1,371	1,700,329	26,799
5	Mar-26	1,614,100	22,322	87,040	1,204	1,701,140	23,525
6	Apr-26	1,611,996	15,871	86,927	856	1,698,923	16,727
7	May-26	1,617,196	9,389	87,207	506	1,704,403	9,895
8	Jun-26	1,614,270	4,465	87,049	241	1,701,319	4,706
9	Jul-26	1,615,352	2,762	87,108	149	1,702,460	2,911
10	Aug-26	1,614,025	2,466	87,036	133	1,701,061	2,599
11	Sep-26	1,613,437	2,756	87,004	149	1,700,441	2,904
12	Oct-26	1,614,497	4,339	87,062	234	1,701,559	4,573
13	Annual	19,360,283	144,040	1,044,001	7,767	20,404,284	151,808
14	Average	1,613,357		87,000		1,700,357	

Schedule E-9

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Test-Year Excess Peak Consumption
(Consumption in MMcf)

Case No.: U-21806
Exhibit No.: A-15 (MA-13)
Schedule: E-9
Page: 1 of 1
Witness: MAhmed
Date: December 2024

Line	(a) Description	(b) Calculation	(c) Source
1	Peak month consumption	941	Exhibit No.: A-15 (MA-7), page 1, column c
2	Peak month customer count	9,238	Exhibit No.: A-15 (MA-11), page 1, column c
3	Base level consumption per customer	45	Tariff Sheet D-10.00
4	Base level consumption	416	(line 2 x line 3) / 1000
5	Excess peak consumption per month	525	line 1 - line 4
6	Number of months	12	Tariff Sheet D-10.00
7	Annual excess peak consumption	6,302	line 5 x line 6

Schedule E-10

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Transition from 2023 Historic Actuals to 12 Months Ending October 2026
Test-Year Revenues, Deliveries, and Customers

Case No.: U-21806
Exhibit No.: A-15 (MA-14)
Schedule: E-10
Page: 1 of 1
Witness: MAhmed
Date: December 2024

Line	Description	(a) 2023 Actuals	(b) Less Non-Base Tariff Items GCR	(c) Less Non-Base Tariff Items Surcharges	(d) Weather Normalization	(e) Change in Determinants	(f) Test Year GCR Factor	(g) Proforma	(h) 12 Months Ending October 2026 Test-Year
	Revenues ($000)								
	Gas Sales [1]								
1	Delivery	$ 1,229,660	$ -	$ -	$ 106,805	$ 6,651	$ -	$ 101,370	$ 1,444,486
2	Fuel	916,875	(916,875)	-	-	-	737,588	-	737,588
	Surcharges								
3	Energy Optimization	80,196	-	(80,196)	-	-	-	-	-
4	PEM/OEM	-	-	-	-	-	-	-	-
5	Total Gas Sales	2,226,731	(916,875)	(80,196)	106,805	6,651	737,588	101,370	2,182,075
	Transportation								
6	Delivery	104,982	-	-	4,853	(2,314)	-	(5,125)	102,396
	Surcharges								
7	Energy Optimization	10,140	-	(10,140)	-	-	-	-	-
8	Total Transportation	115,122	-	(10,140)	4,853	(2,314)	-	(5,125)	102,396
9	Provisions for Refund	(47,758)	47,758		-	-	-	-	-
10	Miscellaneous Revenue [2]	105,825	(105,825)	-	-	-	-	-	-
11	Total Revenue ($000)	$ 2,399,920	$ (974,942)	$ (90,336)	$ 111,658	$ 4,337	$ 737,588	$ 96,245	$ 2,284,471
	Deliveries (MMcf)								
12	Gas Sales [1]	202,300	-	-	22,887	1,094	-	-	226,281
13	Transportation	80,017	-	-	3,201	(1,764)	-	-	81,455
14	Total Deliveries (MMcf)	282,317	-	-	26,088	(670)	-	-	307,736
	Customer Count (12 Mo. Avg)								
	Gas Sales [1]								
15	Billed Count	1,818,283	-	-	-	26,700	-	-	1,844,983
16	Contiguous Count	150	-	-	-	(10)	-	-	140
	Transportation					-			
17	Billed Count	788	-	-	-	6	-	-	794
18	Contiguous Count	964	-	-	-	11	-	-	975
19	Total Customer Count (Avg)	1,820,185	-	-	-	26,706	-	-	1,846,891

Notes
(1) Includes aggregate billed transportation accounts.
(2) Test-Year miscellaneous revenues excluded and presented in the Revenue Requirements testimony

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Proposed Gas Tariff Sheets (MPSC No. 3 – Redlined Version)

For all pricing changes on the following tariff sheets, refer to Exhibit A-16 (SAS-2) Schedule F-2.1, pages 1-3 and A-108 (SAS-8)

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(Continued From Sheet No. A-5.00)

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GAS CUSTOMER CHOICE PROGRAM

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SECTION G
GROUP TRANSPORTATION SERVICE PILOT PROGRAM

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SECTION H
STANDARD CUSTOMER FORMS INDEX

		Sheet No.
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(Continued From Sheet No. C-36.00)

C8. CUSTOMER ATTACHMENT PROGRAM

A. Purpose

The Company proposes to make extension of its gas mains and/or service lines from time to time, at its own cost, to serve applicants whose requirements will not disturb or impair the service to prior users or will not require an expenditure out of proportion to the revenue obtainable therefrom.

The Company reserves the right to delay or deny a request for service under this rule, if fulfilling such a request could, in the Company's opinion, create conditions potentially adverse to the Company or its Customers. Such conditions may include, but are not limited to, safety issues, system operating requirements or capital constraints. The provisions under this Rule are in addition to the existing rules and tariffs for customer gas service.

When relocation or modification of Company facilities to an existing structure with gas service is requested or made necessary by the customer, all costs for the relocation or modification shall be charged to the requesting party.

B. Customer Contribution

A customer contribution shall be required totaling the following components: Connection Fee, any Revenue Deficiency, any Excessive Service Line Fee, and any Direct Charges. Direct Charges include, but are not limited to, any specific license fees, inspection fees, or rights of way fees charged by any political subdivision for any construction provided under this rule and are to be paid directly to the Company. Direct charges shall also include an additional charge per foot for winter construction of all underground construction as installed, excluding conduit, applied to projects constructed during the period of December 15 to April 15, for installation of distribution or service facilities. This charge shall be based on periodic reviews of actual costs by the Company *and may be waived, in whole or in part, at the Company's discretion for certain changes in work schedule or when work conditions or site conditions enable efficient construction and resource deployment which permit the Company to not incur certain costs*.

Any written communication from the Company regarding construction activity and its associated contribution due from the customer, unless specified otherwise in the document, shall have an expiration date of 60 days from the date issued. If either the customer or the Company takes no action by that time, the Company shall have the right to withdraw the proposal or modify the conditions under which it was made.

The Company, at its sole discretion, may waive fees or extend the service line limit for attaching parties located at the Company's storage fields or gas well locations based on the economics of a proposed project, when provided for in writing by the Company. The Company, at its sole discretion, may also waive in writing, fees for select attaching parties or projects where work conditions or site conditions enable efficient construction and resource deployment which permit the Company to not incur certain costs.

C. Payment of Customer Contribution

The Connection Fee, Direct Charges and the Excessive Service Line Fee are payable in lump sum prior to construction. The Company may choose to collect these charges after construction, but prior to the meter being set, at the Company's discretion, when it allows the Company to better align the construction schedule with the customers' desired service dates. The Connection Fee is non-refundable. The Direct Charges and Excessive Service Line Fee are refundable if the service line has not been installed. If the service line has been installed, the Direct Charges and Excessive Service Line Fees are non-refundable. In the case of a lump sum default of payment, and after 180 days have passed, the account will automatically be set up as a fixed monthly surcharge payment.

(Continued on Sheet No. C-38.00)

(Continued From Sheet No. C-39.00)

C8. CUSTOMER ATTACHMENT PROGRAM (Contd)

I. Model Assumptions

Incremental Revenues:

The incremental revenues will be calculated based on current rates and a forecast of the timing and number of customer attachments as well as the customer's annual consumption levels.

Incremental Costs:

(1) Carrying Cost Rate

The carrying cost rate will be based on the weighted rate of debt, preferred stock, equity and associated taxes. The cost will be equal to and weighted in proportion to those authorized in the Company's most recent rate order. The carrying cost rate is equal to *9.11* ~~8.74~~%.

(2) Plant in Service

Plant in Service shall reflect the Company's estimated cost to construct distribution mains, customer service lines, meters and pressure regulators or regulating facilities for the Project. The timing of the facility investment, primarily service lines, will correspond with the projected timing of the customer attachments.

(3) Carrying Costs

The Carrying Costs will be the product of the average of beginning and end-of-year net plant, Plant in Service minus accumulated depreciation minus deferred taxes, multiplied by the Carrying Cost Rate, noted in paragraph 1 above.

(4) Depreciation

Depreciation expense will be the product of Plant in Service multiplied by the appropriate prescribed depreciation rates approved for the Company.

(5) Property Taxes and Other Operating Expenses

Property taxes will be the product of Plant in Service multiplied by the Company's average property tax rate. All other incremental operating expenses will be included as identified. Incremental O&M will at a minimum include a proportional cost for monthly meter reading, billing and mailing.

(6) Discount Rate

The discount rate will be a weighted rate of long-term debt, preferred stock and common equity. The cost will be equal to and weighted in proportion to those authorized in the Company's most recent rate order. Based on the Company's rate order in Case No. *U-21806* ~~U-21490~~, the discount rate is equal to *7.35* ~~7.07~~%.

J. Customer Attachment Project Areas

All gas sold in any area specifically listed below is subject to the following Customer Attachment Project (CAP) charges. CAP areas and charges shall be added to or removed from the list from time to time by the Company.

(Continued on Sheet No. C-41.00)

SURCHARGES

Each Rate Schedule may be subject to Rule No. C8., Customer Attachment Program.

Rate Schedule	Energy Efficiency [1] Program Surcharge (Case No. U-21321) Effective beginning the March 2024 Billing Month [2] [3]
Rate A	$0.3359/Mcf
Rate A-1	0.3359/Mcf
Rate GS-1	0.6638/Mcf
Rate GS-2	0.6638/Mcf
Rate GS-3	
0 – 100,000 / Year	0.6638/Mcf
> 100,000 / Year	0.0318/Mcf
~~Rate GL~~	~~NA~~
Rate ST	
0 – 100,000 / Year	0.6638/Mcf
> 100,000 / Year	0.0318/Mcf
Rate LT	
0 – 100,000 / Year	0.6638/Mcf
> 100,000 / Year	0.0318/Mcf
Rate XLT	
0 – 100,000 / Year	0.6638/Mcf
> 100,000 / Year	0.0318/Mcf
Rate XXLT	
0 – 100,000 / Year	NA
> 100,000 / Year	0.0318/Mcf
Rate CC	Per applicable distribution Rate Schedule
Rate *STT* ~~TOT~~	NA
Rate LTT	*NA*
Rate XLTT	*NA*
Rate XXLTT	*NA*

(1) All surcharges shall be applied on a monthly basis. The customer's consumption will be reviewed annually in the January bill month. Following the annual review, the customer may be subsequently moved to the surcharge level for their applicable rate for the next billing period based on the customer's average consumption for the previous year. No retroactive adjustment will be made due to the application of EE surcharges associated with increases or decreases in consumption.

(2) An Energy Efficiency Program Surcharge amount may vary during specific months as authorized by the Michigan Public Service Commission. The Company will file a new tariff sheet to reflect any change in surcharges once the financial incentive recovery period has been completed.

(3) The Energy Efficiency Program Surcharge for each rate will be shown as above on the monthly utility bill under Other Surcharges for all customers.

SURCHARGES

Each Rate Schedule may be subject to Rule No. C8., Customer Attachment Program.

Rate Schedule	Energy Efficiency Large Gas Transportation Opt-Out Program Surcharge [1] (Case No. U-21321) Effective beginning the March 2024 Billing Month
Rate A	NA
Rate A-1	NA
Rate GS-1	NA
Rate GS-2	NA
Rate GS-3	NA
~~Rate GL~~	~~NA~~
Rate ST	
> 100,000 / Year	$0.0132/Mcf
Rate LT	
> 100,000 / Year	0.0132/Mcf
Rate XLT	
> 100,000 / Year	0.0132/Mcf
Rate XXLT	
> 100,000 / Year	0.0132/Mcf
Rate CC	NA
Rate *STT* ~~TOT~~	NA
Rate LTT	*NA*
Rate XLTT	*NA*
Rate XXLTT	*NA*

(1) Gas Transportation customers on Rate ST, LT, XLT, or XXLT using more than 100,000 Mcf per year may be eligible to opt-out of the Energy Efficiency program. Eligible customers who elect to opt-out of the Energy Efficiency program will pay the Energy Efficiency Large Gas Transportation Opt-Out Program surcharge per Mcf on a monthly basis. Eligibility is determined solely by the Company and is dependent upon terms and conditions of the Energy Efficiency Large Gas Transportation Customer Opt-Out Program as authorized in the April 17, 2012 order in Case No. U-16670.

(2) The Energy Efficiency Large Gas Transportation Opt-Out Program Surcharge will be shown on the monthly utility bill under Other Surcharges for all customers.

SURCHARGES

Rate Schedule	Home Products Credit (Case No. U-*21806* ~~21490~~) Effective for service rendered *November 1, 2025 through September 30, 2027* ~~on and after October 1, 2024~~
Rate A	$(*0.1342* ~~0.1428~~)/Mcf
Rate A-1	(*0.1342* ~~0.1428~~)/Mcf
Rate GS-1	(*0.0909* ~~0.1033~~)/Mcf
Rate GS-2	(*0.0552* ~~0.0623~~)/Mcf
Rate GS-3	(*0.0446* ~~0.0466~~)/Mcf
~~Rate GL~~	~~NA~~
Rate ST	(*0.0313* ~~0.0290~~)/Mcf
Rate LT	(*0.0220* ~~0.0201~~)/Mcf
Rate XLT	(*0.0156* ~~0.0152~~)/Mcf
Rate XXLT	(*0.0074* ~~0.0085~~)/Mcf
Rate *STT* ~~TOT~~	NA
Rate LTT	*NA*
Rate XLTT	*NA*
Rate XXLTT	*NA*
Rate CC	Per applicable distribution Rate Schedule

(Continued From Sheet No. D-8.00)

RATE CATEGORIES (Contd)

Description	Rate Category
~~GENERAL SERVICE OUTDOOR LIGHTING RATE GL - Commercial~~	~~048~~
TRANSPORTATION SERVICE RATE	
Small, Cost-Based	ST
Large, Cost-Based	LT
Extremely Large, Cost-Based	XLT
Extra Extremely Large, Cost-Based	XXLT
TRANSMISSION ONLY TRANSPORTATION SERVICE RATE ~~TOT~~	~~TOT~~
Small Transmission Only, Cost-Based	*STT*
Large Transmission Only, Cost-Based	*LTT*
Extremely Large Transmission Only, Cost-Based	*XLTT*
Extra Extremely Large Transmission Only, Cost-Based	*XXLTT*
CUSTOMER CHOICE RATE CC	CC

RESIDENTIAL SERVICE RATE A

Availability

Subject to any restrictions, this rate is available to any customer desiring gas service for any usual residential use in private family dwellings; tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or multifamily dwellings containing two households served through a single meter.

This rate is not available for resale service, multifamily dwellings containing more than two living units served through a single meter or for tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons or for any other Non-Residential usage.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Gas Rate Book.

Monthly Rate

Customer Charge

$*20.00* ~~15.00~~ per customer per month, plus

Income Assistance Service Provision:

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification from will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Income Assistance Credit: $(*20.00* ~~15.00~~) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future gas utility charges.

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: ($30.27) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future gas utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC, will not be eligible for the RIA provision while enrolled in LIAC.

(Continued on Sheet No. D-11.00)

M.P.S.C. No. 3 - Gas **Sheet No. D-11.00**
Consumers Energy Company

RESIDENTIAL SERVICE RATE A

(Continued From Sheet No. D-10.00)

Monthly Rate (Contd)

Distribution Charge

$ *5.8140* ~~5.1950~~ per Mcf for all Mcf purchased.

Gas Cost Recovery Charge

The gas cost recovery factors are shown on Sheet No. D-5.00.

General Terms and Surcharges

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00 and surcharges shown on Sheet Nos. D-2.00 through D-4.00.

Minimum Charge

The Customer Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Term and Form of Contract

Service under this rate shall not require a written contract.

M.P.S.C. No. 3 - Gas **Sheet No. D-12.00**
Consumers Energy Company

MULTIFAMILY DWELLING SERVICE RATE A-1

Availability

Subject to any restrictions this rate is available to any multifamily dwelling installation containing more than two households served through a single meter and where, in the Company's opinion, it is impractical to provide gas service to each household through an individual meter. This rate is not available for multifamily dwellings containing two households served through a single meter.

Monthly Rate

Customer Charge

$ *20.00* ~~15.00~~ per month

Distribution Charge

$*5.8140* ~~5.1950~~ per Mcf for all Mcf purchased plus
$*0.1217* ~~0.0913~~ per Mcf of excess peak demand

Gas Cost Recovery Charge

The gas cost recovery factors are shown on Sheet No. D-5.00.

General Terms and Surcharges

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00 and surcharges shown on Sheet Nos. D-2.00 through D-4.00.

Minimum Charge

The Customer Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer's bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance outstanding, net of taxes, shall be assessed to any bill which is not paid in full on or before the due date shown thereon.

Determination of Excess Peak Demand

The Mcf used for billing the excess demand shall be equal to all usage in excess of 45 Mcf in the peak month. The peak month shall be that month in the latest 12 months in which the greatest consumption occurred.

If 12 months of historical data are not available for a premises, then the Company shall use an estimated peak usage while accumulating 12 months of data. If, during the accumulation of 12 months of data, any month's actual usage exceeds the original estimated peak usage, then the actual usage shall become the new peak demand. However, if after 12 months the estimated peak usage exceeds the actual peak month's usage, then the customer's bills shall be recalculated using the actual and any overcharge shall be refunded with interest.

Term and Form of Contract

Service under this rate shall not require a written contract.

GENERAL SERVICE RATE
(Rates GS-1, GS-2 and GS-3)

Availability

Subject to any restrictions, this rate is available to any customer desiring gas service for any Non-Residential usage which includes tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons. Gas shall not be purchased under any other rate for any equipment or process which uses gas under this rate.

This rate is not available for residential usage or for resale purposes.

Monthly Rate

	Service Category		
	GS-1	GS-2	GS-3
Principal Customer Charge	$*24.00* ~~18.00~~/meter	$*146.83* ~~133.32~~/meter	$*437.80* ~~324.50~~/meter
Contiguous Customer Charge	*21.00* ~~14.00~~/meter	*45.00* ~~40.00~~/meter	*125.00* ~~80.00~~/meter
Distribution Charge	$*5.1657* ~~4.9147~~/Mcf	$*3.6914* ~~3.5306~~/Mcf	$*3.3422* ~~3.3012~~/Mcf

Selection of Service Category and Rates

Customers may choose the Service Category under which they take service, consistent with the provisions of Rules C4.1, Classes of Service, and C4.2., Choice of Rates. When the Customer is selecting its initial Service Category, the Company must advise them that the estimated economic breakeven point between GS-1 and GS-2 is approximately 1,000 Mcf per year and the estimated economic breakeven point between GS-2 and GS-3 is approximately 10,000 Mcf per year. Economic breakeven points may vary based on the usage and number of customer contiguous accounts. After the initial selection is made, then it is the customer's responsibility to determine when it is appropriate to switch Service Categories, as permitted by Rule C4.2, Choice of Rates.

Gas Cost Recovery Charge

The gas cost recovery factors are shown on Sheet No. D-5.00.

General Terms and Surcharges

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00 and surcharges shown on Sheet Nos. D-2.00 through D-4.00.

Minimum Charge

The Customer Charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer's bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance outstanding, net of taxes, shall be assessed to any bill which is not paid in full on or before the due date shown thereon.

Term and Form of Contract

Service under this rate shall not require a written contract.

This sheet has been cancelled and is reserved for future use.

~~GENERAL SERVICE OUTDOOR LIGHTING RATE GL~~

~~This Rate Is Not Open to New Business~~

~~Availability~~

~~Subject to any restrictions, this rate is available to any commercial or industrial customer for streetlighting or outdoor area lighting service for any system consisting of two or more gas luminaires where the Company has an existing gas distribution system.~~

~~Nature of Service~~

~~The customer shall furnish the necessary posts, luminaires and fixtures. The Company shall install this equipment and make all connections to its gas distribution system. The Company shall supply the gas, renew the mantles, clean the luminaires and paint all metal parts as needed; all other renewals and maintenance shall be paid for by the customer.~~

~~Monthly Rate~~

~~$6.00 per luminaire having a rated consumption of 2.5 cubic feet or less per hour.~~

~~$11.00 per luminaire having a rated consumption of more than 2.5 cubic feet but not more than 4.5 cubic feet per hour.~~

~~General Terms and Surcharges~~

~~This rate is subject to all general terms and conditions shown on Sheet No. D-1.00 and surcharges shown on Sheet Nos. D-2.00 through D-4.00.~~

~~Due Date and Late Payment Charge~~

~~The due date of the customer's bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance outstanding, net of taxes, shall be assessed to any bill which is not paid in full on or before the due date shown thereon.~~

~~Term and Form of Contract~~

~~Minimum term of three years on written contract and year to year thereafter until terminated by mutual consent or upon three months' written notice given by either party.~~

~~Special Terms and Conditions~~

~~The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contributions in aid of construction, monthly charges or other special consideration when the customer requests service, equipment or facilities not normally provided under this rate.~~

TRANSPORTATION SERVICE RATE
(Rates ST, LT, XLT and XXLT)

Availability

Subject to any restrictions, service under this Rate Schedule is available to any customer that could otherwise purchase gas under another Company Rate Schedule. A customer selecting transportation service, is not eligible to receive Gas under any of the Company's firm Gas sales rates for a minimum period of one year from the date the customer commenced taking Transportation Service.

Service provided to Rate Schedule XXLT is available to customers with an annual minimum throughput of 4,000,000 Mcf, subject to an annual review to ensure the minimum requirement is met. Customers served under the XXLT Rate Schedule will be required to operate at a contracted Authorized Tolerance Level of 4% or less.

Under this Rate Schedule, the Company shall transport Gas for the customer to the interconnections between the Company's facilities and those of the customer (points of delivery) from the interconnections between the Company's facilities and those of a third party that delivers Gas to the Company for redelivery to the customer (points of receipt).

A producer or a broker may contract for service on this Rate Schedule for the transportation of Gas from a wellhead through the Company's system to another pipeline, for the transportation of Gas from one pipeline to another pipeline or for the transportation of Gas from a specified interconnection between the Company's facilities and those of a third party for delivery to a specific customer within the Company's integrated distribution system, provided that all Gas transported for a producer or broker pursuant to this Rate Schedule is consumed in and never leaves the State of Michigan after entering the Company's system.

All customers requesting transportation service under this Rate Schedule shall make written application for such service on a form provided by the Company.

Monthly Rate

	Service category			
	ST	**LT**	**XLT**	**XXLT**
Principal Customer Charge	$ *1,185.81* ~~973.32~~/meter	$ *4,631.70* ~~2,026.79~~/meter	$*17,042.79* ~~16,379.74~~/meter	$*41,396.85* ~~43,617.55~~/meter
Contiguous Customer Charge	*105.00* ~~60.00~~ /meter	*105.00* ~~60.00~~ /meter	*105.00* ~~60.00~~/meter	NA
Remote Meter Charge	NA	NA	70.00/meter	70.00 /meter
Transportation Rates	*1.9509* ~~1.4273~~/Mcf	*1.5374* ~~1.3009~~/Mcf	*1.2395* ~~0.9564~~/Mcf	*0.5278* ~~0.5177~~/Mcf *

*The XXLT Transportation Rate reflects a contracted Authorized Tolerance Level of 4%.

Selection of Service Category and Rates

A customer may choose the Service Category under which they take service, consistent with the provisions of Rules C4.1, Classes of Service, and C4.2, Choice of Rates. When the customer is selecting its initial Service Category, the Company must advise them that the estimated economic breakeven point between ST and LT is approximately 100,000 Mcf per year, the estimated economic breakeven point between LT and XLT is approximately 500,000 Mcf per year. The estimated economic breakeven points assume an 8.5% ATL for rates ST, LT and XLT and exclude contiguous customer charges and all surcharges. Economic breakeven points may vary based on the throughput, contracted ATL and number of customer contiguous accounts. After the initial selection is made, then it is the customer's responsibility to determine when it is appropriate to switch Service Categories, as permitted by Rule C4.2, Choice of Rates.

(Continued on Sheet No. E-9.00)

TRANSPORTATION SERVICE RATE

(Rates ST, LT, XLT and XXLT)
(Continued From Sheet No. E-9.00)

Monthly Rate (Contd)

Load Balancing Charge (Contd)

ST, LT and XLT customer's ATL shall be 8.5% of the Customer's ACQ unless the customer contracts for a different percent in accordance with the following table. The Transportation Charge shall be adjusted as follows except for Transportation customers served on XXLT, where service is offered at 4% ATL or less:

Authorized As a % of ACQ Tolerance Level	ST, LT and XLT Transportation Charge Adjustment	XXLT Transportation Charge Adjustment
2.0%	$(*0.0781* ~~0.0732~~) Per Mcf	$(*0.0240* ~~0.0225~~)/Per Mcf
4.0%	$(*0.0540* ~~0.0507~~) Per Mcf *	No Change*
6.5%	$(*0.0240* ~~0.0225~~) Per Mcf	N/A
7.5%	$(*0.0120* ~~0.0113~~) Per Mcf	N/A
8.5%	No Change	N/A
9.5%	$ *0.0120* ~~0.0113~~ Per Mcf	N/A
10.5%	$ *0.0240* ~~0.0225~~ Per Mcf	N/A

*For XXLT customers, the 4% ATL adjustment is reflected in their Transportation Rate, therefore there is no additional ATL adjustment required.

The monthly injection of Gas into the customer's ATL shall be at the customer's discretion except in September and October when any monthly injections in excess of 1.43% of the customer's ACQ, will be charged the Load Balancing Charge. A balance transfer between customers that does not directly result in any physical injection of gas into the Company's system may, in the Company's discretion, be exempted from the 1.43% monthly limit. Such a waiver may be granted once within any 12-month period.

Due Date and Late Payment Charge

The due date of the customer's bill shall be 21 Days from the date of mailing. A late payment charge of 2% of the unpaid balance outstanding, net of taxes, shall be assessed to any bill which is not paid in full on or before the due date shown thereon.

Metering Requirements

All eligible XLT and XXLT customers shall be required to provide, at no expense to the Company, a dedicated telecommunication line(s) as required for metering purposes, to a location specified by the Company. The communication link must be installed and operating prior to a transportation customer receiving service under Service Category XLT or XXLT. The customer shall be responsible for (i) ensuring that the communication links allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees. The Company shall own and maintain the actual metering equipment and modem.

(Continued on Sheet No. E-11.00)

TRANSMISSION ONLY TRANSPORTATION SERVICE RATE ~~TOT~~

(Rates STT, LTT, XLTT and XXLTT)

Availability

Subject to any restrictions, service under this Rate Schedule is available to customers desiring to move gas through the Company's transmission system *only* ~~to a point of delivery off the Company's distribution system~~. *This rate is not available to power generation customers.*

Under this Rate Schedule, the Company will transport natural gas volumes for a customer on the Company's gas transmission system only. The Company, in its sole judgement, shall have the right to determine if capacity is available for transportation under this Rate Schedule.

All customers requesting transmission service under this Rate Schedule shall make written application for such service on a form provided by the Company. The point(s) of receipt and point(s) of delivery shall be mutually agreed upon by Company and Customer and set forth in the contract. Any rates, terms and conditions not covered by Tariff shall be as contained in Company's standard Contract for Transmission Only Transportation Service.

Monthly Rate

~~**Transmission Only Charge**~~

~~$0.4533 per Mcf~~

	Service category			
	STT	*LTT*	*XLTT*	*XXLTT*
Transmission Only Transportation Rates	*$0.7793/Mcf*	*$0.6381/Mcf*	*$0.6126/Mcf*	*$0.3385/Mcf*
Customer Charge:	*208.22/meter*	*1,384.54/meter*	*2,447.53/meter*	*20,365.47/meter*

Selection of Service Category and Rates

A customer may choose the Service Category under which they take service, consistent with the provisions of Rules C4.1, Classes of Service, and C4.2, Choice of Rates. The Company must advise the customer that the estimated economic breakeven point between STT and LTT is approximately 100,000 Mcf per year, the estimated economic breakeven point between LTT and XLTT is approximately 500,000 Mcf per year. After the initial selection is made, then it is the customer's responsibility to determine when it is appropriate to switch Service Categories, as permitted by Rule C4.2, Choice of Rates.

Operational Balance Agreement (OBA)

The aggregate quantity of gas delivered by the Company to the customer's delivery point(s), may be inadvertently greater or less than the aggregate quantity of gas nominated for delivery by the customer. This inadvertent over-delivery or under-delivery of gas by the Company to the customer relative to the nominated quantities shall be governed by a separate OBA with a delivery point operator.

The Company reserves the right to require the customer to balance nominations with physical deliveries on a daily basis, and to reduce the Operational Imbalance to the maximum thresholds identified in the OBA or to a level determined by the Company if no OBA is applicable upon notification, by the Company that such an action is required, and the customer agrees to take the action(s) necessary to reduce the imbalance. If the customer does not make a nomination to reduce the imbalance within 24 hours of such notification by the Company, the customer will pay a penalty of $10/MMBtu per day for each MMBtu of the daily Operation Imbalance.

Gas-in-Kind

Company shall retain 2.45% of all gas received at the Receipt Point(s) to compensate it for the allowance for company-use and lost-and-unaccounted-for gas on Company's system. This volume shall not be included in the quantity available for delivery to Customer. In no event will Customer pay Gas-in-Kind more than once on the same volumes.

(Continued on Sheet No. E-14.00)

TRANSMISSION ONLY TRANSPORTATION SERVICE RATE

(Rates STT, LTT, XLTT and XXLTT)

(Continued From Sheet No. E-13.00)

Monthly Rate (Cotd)

Due Date and Late Payment Charge

The due date of the customer's bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance outstanding, net of taxes, shall be assessed to any bill which is not paid in full on or before the due date shown thereon.

Metering Requirements

All eligible Customers metering requirements shall be in alignment with their delivery point operator according to their Interconnect Agreement.

General Terms and Surcharges

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00 and surcharges shown on Sheet Nos. D-2.00 through D-4.00.

Term and Form of Contract

All service under this rate shall require a written contract with a minimum term of one year and month-to-month thereafter which must be approved by an authorized agent before it shall be binding upon the Company. Customers who choose to terminate their contract shall be required to give the Company a ninety (90) day written notice.

SECTION G
GROUP TRANSPORTATION SERVICE ~~PILOT~~ PROGRAM
STANDARDS AND BILLING PRACTICES

These General Rules and Regulations for Group Transportation Service customers are not to supersede but are in addition to Rule B1, Technical Standards for Gas Service. Under this program, a gas Supplier may aggregate the receipts and deliveries of gas transportation customers taking service under the Company's Gas Transportation Service Rate Schedules by establishing a Group with those transportation customers who have agreed to participate in the program. The Supplier will also establish a Group Administrator, who will enroll transportation customers into the Group, manage the Group, and take responsibility for all fees and penalties associated with the Group. The transportation customer will continue to be billed under the Gas Transportation Service Rate Schedule designated on its transportation service contract, except that, as a member of a Group, Authorized Gas is not available, and the transportation customer will not be subject to the Unauthorized Gas Usage Charge or Load Balancing Charge as set forth in the Gas Transportation Service Rate Schedule.

G1. GENERAL PROVISIONS AND DEFINITIONS

G1.1 Definitions.

As used in this section:

(a) "Account" shall mean transportation customer's facilities and operations directly connected with the individual facilities identified in the transportation service contract between the Company and the transportation customer. The gas for each account shall be measured by a single Company meter.
(b) "Allowance for Use and Loss" is defined in Rule G4.1.C. in Section G.
(c) "Business Day" means Monday through Friday, excluding Company holidays.
(d) "Cubic Foot of Gas" means the volume of gas which occupies one cubic foot when such gas is at a temperature of sixty degrees (60^{o}) Fahrenheit and at a pressure base of fourteen and sixty-five hundredths (14.65) psia dry.
(e) "Day" means a period of 24 consecutive hours (23 hours when changing from Standard to Daylight Time and 25 hours when changing back to Standard Time) beginning at 10:00 AM Eastern Clock Time or at such other time as may be mutually agreed.
(f) "Enrollment" means an identification of the transportation customers to be aggregated in a Group. The Enrollment will be in a form specified by the Company. All Enrollments must be received at least sixty days prior to the calendar month in which the transportation customer will become part of the Group, and an Enrollment will be effective for a period of at least twelve (12) months.
(g) "Gas" means natural gas, manufactured gas, or a combination of the two which meets the "quality" standards as specified in Rule G3, Gas Quality of the Company's Gas Rate Book.
(h) "Gas Rate Book" means the standard rules and regulations and rates governing the sale of natural gas service as approved by the Michigan Public Service Commission.
(i) "Group" shall mean an aggregation of transportation customers, enrolled by a Group Administrator, who take service under Transportation Service Rate Schedules ST, LT, XLT, or XXLT and have agreed to participate in the Program. All transportation customers in a particular customer Group must have the same Authorized Tolerance Level, as defined in Section E.1.1 of the Company's Gas Rate Book.
(j) "Group Administrator" shall mean the administrator of the Group.
(k) "Group Annual Contract Quantity" (GACQ) means the sum of the individual contracted transportation customer Annual Contract Quantities, as defined in section E1.1, enrolled by the Group Administrator in a Group.
(l) "Group Authorized Tolerance Level" (GATL) means the Authorized Tolerance Level (ATL) of the transportation customers in a Group. The GATL shall be established as 2.0%, 4.0%, 6.5%, 7.5%, 8.5%, 9.5%, or 10.5% of the Group's GACQ, and all transportation customers in a Group shall have the same underlying contractual ATL, as defined in section E1.1 of the Company's Gas Rate Book.

(Continued From Sheet No. G-1.00)

G1. GENERAL PROVISIONS AND DEFINITIONS (Contd)

G1.1 Definitions (Contd)

(m) "Group Maximum Daily Quantity" (GMDQ) means the sum of the Maximum Daily quantities of all transportation customers enrolled in the Group, as defined in section E1.1 of the Company's Gas Rate Book.

(n) "Group Minimum Daily Quantity" (GMinDQ) means the minimum amount of gas that should be delivered by the Group Administrator when required to do so at the Company's sole discretion. The GMinDQ will be calculated as a percentage of the GMDQ.

(o) "MMBtu" means one million Btu.

(p) "Month," except as provided with respect to billing, means a period beginning at 10:00 AM Eastern Clock Time on the first day of a calendar month and ending at 10:00 AM Eastern Clock Time on the first day of the following calendar month or at such other time as may be mutually agreed.

(q) "Nominations" means the process by which the Group Administrator notifies the Company of expected transportation quantities.

(r) "Supplier" means an entity who supplies natural gas to an end-use gas transportation customer on Consumers Energy's gas system.

(s) "Total Heating Value Per Cubic Foot" means the number of Btu produced by the combustion, at constant pressure, of one cubic foot of gas, with air of the same pressure and temperature as the gas, when the products of combustion are cooled to the initial temperature of the gas and air, and when the water formed by the combustion is condensed to the liquid state. This definition applies regardless of the equipment used to determine the total heating value per cubic foot.

(t) "Unauthorized Gas Usage Charge" is defined under the Monthly Fees Applicable to the Group Administrator section of the Group Transportation Service ~~Pilot~~ Program.

(Continued on Sheet No. G-3.00)

(Continued From Sheet No. G-2.00)

G1. GENERAL PROVISIONS AND DEFINITIONS (Contd)

G1.2 Application of Rules.

Unless otherwise provided for within this Section G, or under the transportation customer's contracted Transportation Service Rate Schedule, transportation customers and Group Administrators are subject to the provisions of the Company's Gas Rate Book. Transportation customers enrolled in the Group Transportation Service ~~Pilot~~ Program shall be considered customers of the Company.

G1.3 Possession of Gas.

A. Responsibility for Gas

The Company and the transportation customer shall each be responsible for its own equipment and facilities on its own side of a delivery point. The Group Administrator shall have good title or good right to make delivery and, further, shall warrant for itself, its successors and assigns that such gas shall be free and clear of all liens, encumbrances, and claims whatsoever. With respect to any such adverse claim that may arise to said gas or to royalties, taxes, license fees or charges thereon, the transportation customer and Group Administrator shall indemnify and hold the Company harmless from all suits, actions, debts, accounts, damages, costs, losses, and expenses arising from or out of the same.

B. Indemnification of the Company

In the absence of negligence, recklessness or willful misconduct on the part of the Company or of the Company's officers, employees or agents, the transportation customer and the Group Administrator waive any and all claims against the Company, its officers, employees or agents, arising out of or in any way connected with (1) the quality, use or condition of the gas after delivery from the Company's line for the account of such transportation customer; (2) any losses or shrinkage of gas during or resulting from transportation and (3) all other claims and demands arising out of the performance of the duties of the Company, its officers, employees, or agents.

G2. RECORDS, ACCOUNTING AND CONTROL

G2.1 Transmittal of Notices, Bills and Payments.

Transportation customers enrolled in a Group are required to enroll in the electronic billing program Business e-Bill or other electronic invoice delivery program as determined by Consumers Energy. It is the responsibility of the transportation customer to give access to the Group Administrator to view the transportation customer's bill.

G2.2 Nominations, Accounting and Control.

A. All nominations shall be submitted by facsimile, e-mail, or an available electronic nomination system.

B. **Daily**: The Group Administrator shall notify the Company's Transportation Services Department of the daily quantity of gas (in MMBtu) being nominated for delivery to the Company on behalf of the transportation customers in the Group. Such nominations shall be submitted by 2:00 PM Eastern Clock Time on the Business Day prior to the effective day of the proposed delivery. Nominations made after the 2:00 PM deadline shall be accepted at the sole discretion of the Company.

(Continued on Sheet No. G-4.00)

(Continued From Sheet No. G-4.00)

G4. SERVICE REQUIREMENTS

G4.1 Quantities.

A. The Group Administrator may deliver, or cause to be delivered, and the Company shall, subject to other provisions in the Company's Gas Rate Book, accept quantities of gas up to the GMDQ specified in the Group transportation service contract.

B. Deliveries to the Company may be made by or on behalf of the Group Administrator at existing interconnections between the gas transmission facilities of the Company and other pipeline systems. These points of receipt shall be those that are agreed to from time to time by the Group Administrator and the Company.

C. The Company shall retain 2.45 percent of all gas received for transportation customers in the Group to compensate it for the Company's use and lost and unaccounted for on the Company's system ("Allowance for Use and Loss"). This volume shall not be included in the quantity available for delivery to transportation customers in the Group.

D. The amount of gas available for use by the Group will be calculated as the amount of gas received by the Company less the allowance for gas-in-kind, plus the net effect of any balance transfers, plus any withdrawals from the Group's storage balance. For purposes of this calculation, gas transferred to or from another Group or transportation customer during the billing month shall not be considered.

If, in any month, the amount of gas available for use by the Group is more than the quantity of gas taken by the transportation customers enrolled in the Group at their points of delivery, then the difference shall be retained by the Company and delivered to the Group in those succeeding months when the amount of gas available for use by the Group is less than the requirements of those transportation customers enrolled in the Group. Such subsequent deliveries to the Group shall be subject to the withdrawal limitations identified under the Monthly Fees Applicable to the Group Administrator section of the Group Transportation Service ~~Pilot~~ Program. Should the amount of gas available for use by the Group at any month-end exceed the GATL, then the Company shall assess the Group Administrator a Load Balancing Charge for any month-end balance that exceeds the GATL.

E. In the event of the termination of a Group Administrator's contract, the Group Administrator must transfer any gas retained by the Company to another Group or to a transportation customer taking service under a Transportation Service Rate Schedule within 60 days. If the Group Administrator has not withdrawn or transferred all of the gas retained by the Company within 60 days, the Company will cash out the remaining balance at a rate of $1.00 per Mcf.

F. Upon joining a Group, any volumes in the transportation customer's Authorized Tolerance Level balance will transfer into the Group Administrator's Group Authorized Tolerance Level balance. Upon leaving a Group, the transportation customer's Authorized Tolerance Level will follow the transportation customer and the Group Administrator's Group Authorized Tolerance Level will be reduced by the transportation customer's Authorized Tolerance Level.

(Continued on Sheet No. G-6.00)

(Continued From Sheet No. G-5.00)

G4. SERVICE REQUIREMENTS (Contd)

G4.2 Delivery Pressure.

All deliveries of gas by the Group Administrator and the Company shall be made at a pressure sufficient to effect same, provided that neither party shall directly or indirectly cause the other to make such deliveries at a pressure in excess of that which would be a reasonably expected maximum.

G4.3 Shutoff of Service.

The Company shall not be required to perform service under a Group transportation service contract if the Group Administrator has failed to comply with any and all terms of the Group Administrator's contract and the Company's Gas Rate Book.

G5. BILLING

On or before the last Business Day of each calendar month, the Company shall endeavor to render a statement to the Group Administrator for service during the prior calendar month. Such statement will also include any Unauthorized Gas Usage Charges, failure fees, or Load Balancing Charges incurred by the Group.

G6. UNAUTHORIZED GAS USAGE CHARGE

If, in any month, the Group exceeds the amount of gas available for use by the Group, the excess amount will be treated as unauthorized use and be subject to the Unauthorized Gas Usage Charge as designated under the Monthly Fees Applicable to the Group Administrator section of the Group Transportation Service ~~Pilot~~ Program.

G7. CUSTOMER PARTICIPATION IN A GROUP

Transportation customers may elect to participate in the Group Transportation Service ~~Pilot~~ Program, and Group Administrators may solicit transportation customer participation at any time. However, transportation customer enrollments must be received by the Company, in a form acceptable to the Company, by the first business day of the calendar month 60 days preceding the customer's enrollment in the Group. Each Supplier may elect to have an unlimited number of Groups with a maximum enrollment of 200 contract accounts per group. A Supplier can select desired ATL for each group. A customer who is a transportation customer of the Company must comply with all requirements of the Transportation Service Rate Schedule on which it takes service, excluding any penalties for Unauthorized Gas Usage Charges or Load Balancing Charges, which will be the responsibility of the Group Administrator.

The transportation customer's enrollment in a Group shall remain in effect for a period of at least twelve (12) months from the date of the enrollment. During that time, gas delivered to the transportation customer shall be provided to the Company by the Group Administrator of the Group in which the transportation customer is enrolled. A transportation customer enrolled in a Group cannot be enrolled in more than one Group at any time and is not eligible to designate receipts from any source other than the Group in which it is enrolled. The transportation customer's selection of a Group shall be effective until: (i) terminated by the transportation customer or the Supplier, (ii) the Supplier becomes disqualified from participating in the Group Transportation Service ~~Pilot~~ Program, or (iii) the Company receives an enrollment for that transportation customer in another Group. The Company shall incur no liability for relying on information received from a transportation customer or a Group Administrator which the Company believes to be genuine.

Transportation customers may also request to de-enroll in the Group Transportation Service ~~Pilot~~ Program, and those requests for de-enrollment must be received at least 60 days prior to desired effective date. Enrollment will remain in effect through the last day of the calendar month. Customers will transfer to another group or return to the Gas Transportation program effective on the first day of the month following de-enrollment. Customers leaving a Group will not retain any portion of the Group's Authorized Tolerance Level Balance. Upon de-enrollment from the Group Transportation Service ~~Pilot~~ Program, the customer will be subjected to the Company's Transportation Service Rate Schedule.

(Continued From Sheet No. G-7.00)

G10. GROUP TRANSPORTATION SERVICE ~~PILOT~~ PROGRAM STANDARDS OF CONDUCT

This rule is intended to promote fair competition and a level playing field among all participants involved in transportation within the Company's regulated gas service territory. The Company will conduct its business to conform to the following Group Transportation Standards of Conduct:

A. The Company will apply any tariff provision relating to transportation service in the same manner without discrimination to all similarly situated persons.

B. The Company will not give its marketing affiliate or customers of its affiliate preference over any other non-affiliated gas marketers or their customers in matters relating to transportation service including, but not limited to, nominating, balancing, metering, billing, storage, standby service, curtailment policy or price discounts.

C. The Company will not communicate to any customer, Supplier, Group Administrator, or third parties that any advantage may accrue to such customer, Supplier, Group Administrator, or other third party in the use of the Company's services as a result of that customer, Supplier, Group Administrator, or other third party dealing with its marketing affiliate and shall refrain from giving any appearance that it speaks on behalf of its affiliate.

D. The Company will process all similar requests for transportation service in the same manner and within the same period of time.

E. The Company will not provide leads or provide market sensitive information regarding a current or potential customer or marketer to its marketing affiliate. If a customer requests information about marketers, the Company will provide a list of all marketers operating on its system, including its affiliate, but will not promote its affiliate.

F. If a customer makes a request in writing that its historic volumetric sales and transportation data be provided to a particular marketer or marketers in general, that request will be honored by the Company until revoked by the customer or after 5 years from the date of the request. To the extent the Company provides to its marketing affiliate a discount or information related to the transportation, sales or marketing of natural gas, including but not limited to the Company's customer lists, that is not readily available or generally known to any other marketer, Supplier, or Group Administrator, or has not been authorized by a customer, it will provide details of such discount or provide the information contemporaneously to all potential marketers on its system that have requested such information. A marketer may make a standing request for contemporaneous disclosure of such information.

G. The Company will not condition or tie its agreement to release interstate pipeline capacity to any agreement by a gas marketer, customer, Supplier, Group Administrator, or pipeline transporter relating to any service in which its marketing affiliate is involved.

H. The Company will not condition or tie an agreement to provide a transportation discount to any agreement by a marketer, customer, Supplier, Group Administrator, or pipeline transporter relating to any service in which its marketing affiliate is involved.

I. The Company's operating employees and the operating employees of its marketing affiliate will function independently of each other, be employed by separate business entities, and reside in separate offices.

J. The Company will keep separate books of accounts and records from those of its marketing affiliate.

(Continued From Sheet No. G-8.00)

G11. GROUP TRANSPORTATION SERVICE ~~PILOT~~ PROGRAM STANDARDS OF CONDUCT COMPLAINT PROCEDURES

If the Company receives a verbal complaint related to its Rules, Regulations and Rate Schedules Governing the Sale or Transportation of Natural Gas, M.P.S.C. No. 2, Section G10, Group Transportation Service ~~Pilot~~ Program Standards of Conduct, the Company will attempt to resolve the complaint on an informal basis. If the Company and the complainant are unable to resolve the complaint on an informal basis, the procedures outlined below will be followed:

A. Complainant will route all formal complaints in writing to:

Consumers Energy
One Energy Plaza
Jackson, MI 49201

Attention: Legal Department

B. The Company will acknowledge the receipt of the formal written complaint, in writing, within five working days of receipt by the Company.

C. The Company will confirm and amend the prepared written statement of the complainant to ensure the complaint includes the name of the complainant, relevant dates, and specific claims.

D. The Company will prepare a written statement communicating to the complainant the results of the Company's preliminary investigation within 30 days of the initial receipt of the complaint by the Company with a description of the action taken or proposed to be taken.

E. (1) If the complainant is satisfied with the action taken or proposed to be taken, complainant will acknowledge its agreement by signing and returning a copy of the Company's written statement addressing the action taken or proposed to be taken.

(2) If the complainant is not satisfied with the Company's response, then the complainant may address the complaint to the Commission.

F. If a transportation customer has a complaint against a Group Administrator or Supplier, the transportation customer should try to resolve it first with the Group Administrator or Supplier. If the complaint is unresolved, the transportation customer may address the complaint to the Commission. The Company shall have no responsibility for resolving disputes between transportation customers and Group Administrators or Suppliers but shall provide information as requested by the transportation customer or the Commission.

GROUP TRANSPORTATION SERVICE ~~PILOT~~ PROGRAM RATE

Availability

Subject to any restrictions, participation in the Group Transportation Service ~~Pilot~~ Program is available to any Supplier who wishes to aggregate the receipts and deliveries of transportation customers taking service under Transportation Service Rate Schedules. All transportation customers in a particular Group must have the same Authorized Tolerance Level, as defined in Section E.1.1 of the Company's Gas Rate Book. Furthermore, all transportation customers in a Group shall be enrolled by the Supplier's Group Administrator, utilizing a form specified by the Company.

Under this Program, the Company shall transport gas for the Group from the interconnections between the Company's facilities and those of a third party that delivers gas to the Company for redelivery (points of receipt) to the interconnections between the Company's facilities and those of the transportation customers within the Group (points of delivery). Each Group shall have a Group Administrator who will be responsible for all penalties associated with the aggregation of receipts and deliveries of the Group. Each Supplier desiring to establish a Group shall make written application for such service on a form provided by the Company. The Company will convert the transportation customer's consumption from Mcf to MMBtu using monthly system-average Btu content. The Company, at its discretion, shall issue operation flow orders, or take other action which is deemed necessary, to ensure system reliability. The Company will act as supplier of last resort under the Program.

A transportation customer who is part of a Group remains subject to the obligations of both the Transportation Service Rate Schedule under which it takes service and the transportation service contract between the transportation customer and the Company. The transportation customer will continue to be billed under the Transportation Service Rate Schedule designated on its transportation service contract. Members of a Group will not be subject to the Unauthorized Gas Usage Charge or Load Balancing Charge as set forth in the Transportation Service Rate Schedule. A transportation customer whose account is in arrears shall not be eligible to be part of a Group. Enrollment in a Group is voluntary.

Monthly Fees Applicable to the Group Administrator

Group Administrative Fee	$200/group
Customer Account Maintenance Fee	$5.00/customer account enrolled

Unauthorized Gas Usage Charge

The Group Administrator shall be billed for unauthorized usage at the rate for service under Transportation Service Rate ST plus an Unauthorized Gas Usage Charge. Such Unauthorized Gas Usage Charge shall be the highest Midpoint price reported for Michigan or Chicago LDC's during the applicable month as reported by Gas Daily or, in the event that Gas Daily discontinues its reporting of such prices, any comparable reporting service, plus $10 per Mcf for all gas taken by the Group in excess of the amount of gas available for use by the Group, as defined in Section G4.1D.

Monthly withdrawals from the Group's previous month-end storage balance during November through March will be limited to 3% of the Group's ACQ.

(Continued on Sheet No. G-11.00)

GROUP TRANSPORTATION SERVICE ~~PILOT~~ PROGRAM RATE

(Continued From Sheet No. G-10.00)

Monthly Fees Applicable to the Group Administrator (Contd)

Load Balancing Charge

Should the amount of gas available for use by the Group at any month-end exceed the Group Authorized Tolerance Level, then the Company shall assess the Group Administrator a Load Balancing Charge of $1.00 per MMBtu for the excess. In addition, there is a 2.0 percent gas-in-kind for fuel used for injection for any month-end balance of gas that exceeds the Group Authorized Tolerance Level and is in excess of the prior month-end storage balance.

The monthly injection of gas into the Group's ATL shall be at the Group Administrator's discretion, except in September and October when any monthly injections in excess of 1.43% of the Group's ACQ shall be charged the Load Balancing Charge.

Due Date and Late Payment Charge

The due date of the Group Administrator's bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance outstanding, net of taxes, shall be assessed to any bill which is not paid in full on or before the due date shown thereon.

Term and Form of Contract

All service under the Group Transportation Service ~~Pilot~~ Program shall require a written contract with a term of one year, and month-to-month thereafter, which must be approved by an officer of the Company or a duly authorized agent before it shall be binding upon the Company.

Schedule F-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenue by Rate Schedule
Total Revenue

Case No.: U-21806
Exhibit No.: A-16 (SAS-1)
Schedule: F-2
Page: 1 of 2
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Present Revenue	(c) Proposed Revenue	(d) Difference Revenue	(e) Difference Percent
		$000	$000	$000	%
	Residential Service				
1	Single Family Dwelling A	$ 1,577,268	$ 1,768,761	$ 191,493	12.1
2	Multifamily Dwelling A-1	53,863	57,769	3,906	7.3
3	Total Residential Service	1,631,131	1,826,530	195,399	12.0
	General Service				
4	Small Service GS-1	271,029	287,141	16,112	5.9
5	Medium Service GS-2	224,497	231,882	7,385	3.3
6	Large Service GS-3	55,417	56,442	1,025	1.9
7	Outdoor Lighting GL	-	-	-	NA
8	Total General Service	550,943	575,465	24,522	4.5
9	Total Gas Sales [1]	2,182,075	2,401,996	219,921	10.1
	Transportation				
10	Small Transport ST	34,864	46,678	11,814	33.9
11	Large Transport LT	27,199	34,964	7,765	28.5
12	Extremely Large Transport XLT	30,204	38,128	7,923	26.2
13	Extra Extremely Large Transport XXLT	10,129	10,216	87	0.9
14	Total Transportation	102,396	129,985	27,589	26.9
15	Total Service (Delivery & Fuel)	$ 2,284,471	$ 2,531,981	$ 247,510	10.8
16	Additional Late Payment Charge Revenue	0	498	498	
17	Revenue Increase/(Decrease) Due to Rounding	0	(0)	(0)	
18	Revenue (Sufficiency)/Deficiency	$ 2,284,471	$ 2,532,479	248,008	10.9

Notes
[1] Includes aggregate billed transportation accounts.

Schedule F-2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenue by Rate Schedule
Delivery Revenue

Case No.: U-21806
Exhibit No.: A-16 (SAS-1)
Schedule: F-2
Page: 2 of 2
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Present Revenue	(c) Proposed Revenue	(d) Difference Revenue	(e) Difference Percent
		$000	$000	$000	%
	Residential Service				
1	Single Family Dwelling A	$ 1,076,910	$ 1,268,403	$ 191,493	17.8
2	Multifamily Dwelling A-1	34,084	37,990	3,906	11.5
3	Total Residential Service	1,110,994	1,306,393	195,399	17.6
	General Service				
4	Small Service GS-1	172,968	189,080	16,112	9.3
5	Medium Service GS-2	131,566	138,951	7,385	5.6
6	Large Service GS-3	28,958	29,983	1,025	3.5
7	Outdoor Lighting GL	-	-	-	NA
8	Total General Service	333,492	358,014	24,522	7.4
9	Total Gas Sales [1]	1,444,486	1,664,407	219,921	15.2
	Transportation				
10	Small Transport ST	34,864	46,678	11,814	33.9
11	Large Transport LT	27,199	34,964	7,765	28.5
12	Extremely Large Transport XLT	30,204	38,128	7,923	26.2
13	Extra Extremely Large Transport XXLT	10,129	10,216	87	0.9
14	Total Transportation	102,396	129,985	27,589	26.9
15	Total Service (Delivery Only)	1,546,883	$ 1,794,393	$ 247,510	16.0
16	Additional Late Payment Charge Revenue	0	498	498	
17	Revenue Increase/(Decrease) Due to Rounding	0	(0)	(0)	
18	Revenue (Sufficiency)/Deficiency	$ 1,546,883	$ 1,794,891	248,008	16.0

Notes
[1] Includes aggregate billed transportation accounts.

Schedule F-2.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Rates by Rate Schedule

Case No.: U-21806
Exhibit No.: A-16 (SAS-2)
Schedule: F-2.1
Page: 1 of 3
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Units	(c) Present	(d) Proposed
	Residential Class			
	Single Family Dwelling A			
1	Customer Charge	$/Mth	15.00	20.00
2	Income Assistance - RIA Program	$/Mth	(15.00)	(20.00)
3	Income Assistance - LIAC Program	$/Mth	(30.27)	(30.27)
4	Distribution Charge	$/Mcf	5.1950	5.8140
	Multifamily Dwelling A-1			
5	Customer Charge	$/Mth	15.00	20.00
6	Excess Peak Charge	$/Mcf	0.0913	0.1217
7	Distribution Charge	$/Mcf	5.1950	5.8140
	General Service			
	Small Service GS-1			
8	Customer Charge - Principal	$/Mth	18.00	24.00
9	Customer Charge - Contiguous	$/Mth	14.00	21.00
10	Distribution Charge	$/Mcf	4.9147	5.1657
	Medium Service GS-2			
11	Customer Charge - Principal	$/Mth	133.32	146.83
12	Customer Charge - Contiguous	$/Mth	40.00	45.00
13	Distribution Charge	$/Mcf	3.5306	3.6914
	Large Service GS-3			
14	Customer Charge - Principal	$/Mth	324.50	437.80
15	Customer Charge - Contiguous	$/Mth	80.00	125.00
16	Distribution Charge	$/Mcf	3.3012	3.3422
	Outdoor Lighting GL			
17	Single Mantle	$/Lum.	6.00	-
18	Multiple Mantle	$/Lum.	11.00	-
	Transportation			
	Small Transport ST			
19	Customer Charge - Principal	$/Mth	973.32	1,185.81
20	Customer Charge - Contiguous	$/Mth	60.00	105.00
21	Distribution Charge	$/Mcf	1.4273	1.9509
	Large Transport LT			
22	Customer Charge - Principal	$/Mth	2,026.79	4,631.70
23	Customer Charge - Contiguous	$/Mth	60.00	105.00
24	Distribution Charge	$/Mcf	1.3009	1.5374
	Extremely Large Transport XLT			
25	Customer Charge - Principal	$/Mth	16,379.74	17,042.79
26	Customer Charge - Contiguous	$/Mth	60.00	105.00
27	Remote Meter Charge	$/Mth	70.00	70.00
28	Distribution Charge	$/Mcf	0.9564	1.2395

Schedule F-2.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Rates by Rate Schedule

Case No.: U-21806
Exhibit No.: A-16 (SAS-2)
Schedule: F-2.1
Page: 2 of 3
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Units	(c) Present	(d) Proposed
	Extra Extremely Large Transport XXLT			
29	Customer Charge - Principal	$/Mth	43,617.55	41,396.85
30	Remote Meter Charge	$/Mth	70.00	70.00
31	Distribution Charge	$/Mcf	0.5177	0.5278
	Authorized Tolerance Level (ST, LT, XLT, XXLT) [1]			
32	2.0% ATL	$/Mcf	(0.0732)	(0.0781)
33	4.0% ATL	$/Mcf	(0.0507)	(0.0540)
34	6.5% ATL	$/Mcf	(0.0225)	(0.0240)
35	7.5% ATL	$/Mcf	(0.0113)	(0.0120)
36	8.5% ATL	$/Mcf	-	-
37	9.5% ATL	$/Mcf	0.0113	0.0120
38	10.5% ATL	$/Mcf	0.0225	0.0240
	Customer Attachment Program			
39	Discount Rate	%	7.07	7.35
40	Carrying Cost Rate	%	8.74	9.11
	Other Transportation			
41	Authorized Gas Use Charge	$/Mcf	1.00	1.00
42	Unauthorized Gas Use Charge	$/Mcf	10.00	10.00
43	Load Balancing Charge	$/MMBtu	0.25	0.25
44	EUT Gas In Kind	%	2.45	2.45
	Non-Transmitting Gas Meter - Automated Meter Reading (AMR) Provision			
45	One Time Charge Prior to AMR Install	$/Customer	109.94	109.94
46	One Time Charge After AMR Install	$/Customer	177.53	177.53
47	Monthly Charge	$/Customer	6.03	6.03

Notes

[1] Only the 2.0% ATL adjustment is available to XXLT and the 4.0% ATL credit is subtracted to get a credit of $(0.024)

Schedule F-2.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Rates by Rate Schedule

Case No.: U-21806
Exhibit No.: A-16 (SAS-2)
Schedule: F-2.1
Page: 3 of 3
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Units	(c) Present	(d) Proposed
	Transmission-Only			
48	Small Transmission-Only STT			
49	Customer Charge	$/Mth	-	208.22
50	Transmission Charge	$/Mcf	0.4533	0.7793
	Large Transmission-Only LTT			
51	Customer Charge	$/Mth	-	1,384.54
52	Transmission Charge	$/Mcf	0.4533	0.6381
	Extremely Large Transmission-Only XLTT			
53	Customer Charge	$/Mth	-	2,447.53
54	Transmission Charge	$/Mcf	0.4533	0.6126
	Extra Extremely Large Transmission-Only XXLTT			
55	Customer Charge	$/Mth	-	20,365.47
56	Transmission Charge	$/Mcf	0.4533	0.3385

Schedule F-2.2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Rate Design Targets
($000)

Case No.: U-21806
Exhibit No.: A-16 (SAS-3)
Schedule: F-2.2
Page: 1 of 2
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Source	(c) Total	(d) Residential	(e) General Service GS-1	(f) General Service GS-2	(g) General Service GS-3	(h) Transportation ST	(i) Transportation LT	(j) Transportation XLT	(k) Transportation XXLT
1	Cost of Service Study (COSS)	Exhibit A-16 (SMG-2), Schedule F-1.1, page 1, line 46	$ 1,794,891	$ 1,312,961	$ 187,499	$ 134,448	$ 31,142	$ 46,013	$ 34,279	$ 37,538	$ 11,011
2	Adjustment - Low Income Provision Credits	Exhibit A-16 (SAS-3), page 2, column (e)	-	(6,189)	2,522	2,012	510	408	304	335	98
3	Adjustment - Storage	WP-EAD-29 column (f)	-	-	-	-	-	257	261	375	(893)
4	COSS, Net	Sum Lines 1 - 3	1,794,891	1,306,773	190,021	136,460	31,652	46,678	34,844	38,248	10,216
5	Adjustment - Rate Stability		-	-	(882)	2,538	(1,656)	-	120	(120)	-
6	Adjusted COSS	Sum Lines 4 - 5	1,794,891	1,306,773	189,139	138,999	29,995	46,678	34,964	38,128	10,216
7	Test Year Present Revenue	Exhibit A-16 (SAS-4), pages 1-10	1,546,883	1,110,994	172,968	131,566	28,958	34,864	27,199	30,204	10,129
8	Revenue (Sufficiency)/Deficiency	Line 6 - Line 7	248,008	195,779	16,171	7,432	1,037	11,814	7,765	7,923	87
9	Incremental Late Payments	WP-SAS-2	498	380	59	47	12	-	-	-	-
10	Adjusted Revenue (Sufficiency)/Deficiency	Line 8 - Line 9	247,510	195,399	16,112	7,385	1,025	11,814	7,765	7,923	87
11	Rate Design Targets	Line 7 + Line 10	$ 1,794,393	$ 1,306,393	$ 189,080	$ 138,951	$ 29,983	$ 46,678	$ 34,964	$ 38,128	$ 10,216
12	% Rate Increase	(Line 11 - Line 7) / Line 7		17.6%	9.3%	5.6%	3.5%	33.9%	28.5%	26.2%	0.9%
	Calculation of Rate Stability Adjustment										
13	COSS, Net of Provision Credits	Line 1+ Line 2	$ 1,794,891	$ 1,306,773	$ 190,021	$ 136,460	$ 31,652	$ 46,678	$ 34,844	$ 38,248	$ 10,216
14	COSS % Rate Increase	(Line 13 - Line 7) / Line 7	16.0%	17.6%	9.9%	3.7%	9.3%	33.9%	28.1%	26.6%	0.9%
15	% Rate Increase - Stability Target				9.3%	5.6%	3.6%	33.9%	28.5%	26.2%	
16	Adjusted Rate Design Target	Line 7 * (1 + Line 15)		-	189,139	138,999	29,995	46,678	34,964	38,128	-
17	Rate Stability Adjustment	Line 16 - Line 13	-	$ -	$ (882)	$ 2,538	$ (1,656)	$ -	$ 120	$ (120)	$ -
					-			-			

Notes

$	120	Shifted into LT and XLT from ST
$	2,538	Shifted into GS-2 from GS-1 and GS-3

No adjustments have been made to Residential or XXLT. These rates are cost based.

Schedule F-2.2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Rate Design Targets
Allocation of Low Income Provision Credits
($000)

Case No.: U-21806
Exhibit No.: A-16 (SAS-3)
Schedule: F-2.2
Page: 2 of 2
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) COS % of Total COS	(c) RIA Discount Allocation	(d) LIAC Discount Allocation	(e) Total	(f)	(g)	(h)	(i)	(j)
	Sales									
1	Residential A and A1	72.32%	$ 13,018	$ 3,152	$ 16,170					
2	Subtotal Residential	72.32%	13,018	3,152	16,170					
3	General Service - Rate GS-1	11.28%	2,031	492	2,522					
4	General Service - Rate GS-2	9.00%	1,620	392	2,012					
5	General Service - Rate GS-3	2.28%	410	99	510					
6	Subtotal General Service	22.56%	4,060	983	5,044					
7	Transportation Service - Rate ST	1.82%	328	79	408					
8	Transportation Service - Rate LT	1.36%	245	59	304					
9	Transportation Service - Rate XLT	1.50%	269	65	335					
10	Transportation Service - Rate XXLT	0.44%	79	19	98					
11	Subtotal Transportation	5.12%	922	223	1,145					
12	Total Low Income Provision Credits	100.00%	$ 18,000	$ 4,359	$ 22,359					

		Total	Residential	Rate GS-1	Rate GS-2	Rate GS-3	Rate ST	Rate LT	Rate XLT	Rate XXLT
13	Total Cost of Service [1] [2]	$ 2,561,146	$ 1,852,251	$ 288,927	$ 230,440	$ 58,375	$ 46,698	$ 34,848	$ 38,331	$ 11,275
14	Cost of Service Percentage	100.00%	72.32%	11.28%	9.00%	2.28%	1.82%	1.36%	1.50%	0.44%

Notes

[1] Exhibit A-16 (SMG-2), Schedule F-1.1, page 1, line 43

[2] Includes the cost of fuel

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
Residential Single Family Dwelling A

Case No.: U-21806
Exhibit No.: A-16 (SAS-4)
Schedule: F-3
Page: 1 of 11
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Billing Determinants Units	(d) Present Rates	(e) Present Revenue	(f) Proposed Rates	(g) Proposed Revenue
				$/unit	$000	$/unit	$000
	Delivery						
1	Customer [1]	1,700,357	Mthly	15.00	$ 306,064	20.00	$ 408,086
2	Distribution Mcf/mth [2]	151,820	MMcf	5.1950	788,705	5.8140	882,677
	Provisions						
3	Income Assistance - RIA [3]	75,000	Mthly	(15.00)	(13,500)	(20.00)	(18,000)
4	Income Assistance - LIAC [3]	12,000	Mthly	(30.27)	(4,359)	(30.27)	(4,359)
5	Total Delivery				1,076,910		1,268,403
	Fuel						
6	GCR Sales [4]	151,808	MMcf	3.2960	500,358	3.2960	500,358
7	Alternative Fuel Sales [5]	12.333	MMcf	-	-	-	-
8	Total Fuel	151,820			500,358		500,358
9	Total Service (Delivery & Fuel)				$ 1,577,268		$ 1,768,761

[1] Exhibit A-15 (MA-11), Schedule E-7
[2] Exhibit A-15 (MA-7), Schedule E-3
[3] Sum of column (b) lines 3 and 4 agrees to Exhibit A-15 (MA-12), Schedule E-8, line 14, column (d)
[4] Exhibit A-15 (MA-7), Schedule E-3
[5] Exhibit A-15 (MA-7), Schedule E-3

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
Residential Multifamily Dwelling A-1

Case No.: U-21806
Exhibit No.: A-16 (SAS-4)
Schedule: F-3
Page: 2 of 11
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Billing Determinants Quantity Present	(c) Billing Determinants Quantity Proposed	(d) Units	(e) Present Rates	(f) Present Revenue	(g) Proposed Rates	(h) Proposed Revenue
					$/unit	$000	$/unit	$000
	Delivery							
1	Customer [1]	9,238		Mthly	15.00	$ 1,663	20.00	$ 2,217
2	Excess Peak Mcf/Mth [2]	6,302	1,092	MMcf	0.0913	575	0.1217	133
3	Distribution Mcf/Mth [3]	6,130		MMcf	5.1950	31,845	5.8140	35,639
4	Total Delivery					34,084		37,990
	Fuel							
5	GCR Sales [4]	6,001		MMcf	3.2960	19,779	3.2960	19,779
6	Alternative Fuel Sales [5]	129		MMcf	-	-	-	-
7	Total Fuel	6,130				19,779		19,779
8	Total Service (Delivery & Fuel)					$ 53,863		$ 57,769

Notes

[1] Exhibit A-15 (MA-11), Schedule E-7
[2] Exhibit A-15 (MA-13), Schedule E-9, line 7, column (b)
[3] Exhibit A-15 (MA-7), Schedule E-3
[4] Exhibit A-15 (MA-7), Schedule E-3
[5] Exhibit A-15 (MA-7), Schedule E-3

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
General Small Service GS-1

Case No.: U-21806
Exhibit No.: A-16 (SAS-4)
Schedule: F-3
Page: 3 of 11
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Billing Determinants Units	(d) Present Rates	(e) Present Revenue	(f) Proposed Rates	(g) Proposed Revenue
				$/unit	$000	$/unit	$000
	Delivery						
1	Customer [1]	119,324	Mthly	18.00	$ 25,774	24.00	$ 34,365
2	Contiguous Account [2]	30	Mthly	14.00	5	21.00	7
3	Distribution Mcf/Mth [3]	29,949	MMcf	4.9147	147,189	5.1657	154,707
4	Total Delivery				172,968		189,080
	Fuel						
5	GCR Sales [4]	29,752	MMcf	3.2960	98,061	3.2960	98,061
6	Alternative Fuel Sales [5]	197	MMcf	-	-	-	-
7	Total Fuel	29,949			98,061		98,061
8	Total Service (Delivery & Fuel)				$ 271,029		$ 287,141

Notes

[1] Exhibit A-15 (MA-11), Schedule E-7
[2] Exhibit A-15 (MA-11), Schedule E-7
[3] Exhibit A-15 (MA-7), Schedule E-3
[4] Exhibit A-15 (MA-7), Schedule E-3
[5] Exhibit A-15 (MA-7), Schedule E-3

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
General Medium Service GS-2

Case No.: U-21806
Exhibit No.: A-16 (SAS-4)
Schedule: F-3
Page: 4 of 11
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Billing Determinants Units	(d) Present Rates	(e) Present Revenue	(f) Proposed Rates	(g) Proposed Revenue
				$/unit	$000	$/unit	$000
	Delivery						
1	Customer [1]	15,574	Mthly	133.32	$ 24,916	146.83	$ 27,441
2	Contiguous Account [2]	59	Mthly	40.00	28	45.00	32
3	Distribution Mcf/Mth [3]	30,200	MMcf	3.5306	106,623	3.6914	111,479
4	Total Delivery				131,566		138,951
	Fuel						
5	GCR Sales [4]	28,195	MMcf	3.2960	92,931	3.2960	92,931
6	Alternative Fuel Sales [5]	2,005	MMcf	-	-	-	-
7	Total Fuel	30,200			92,931		92,931
8	Total Service (Delivery & Fuel)				$ 224,497		$ 231,882

Notes

[1] Exhibit A-15 (MA-11), Schedule E-7
[2] Exhibit A-15 (MA-11), Schedule E-7
[3] Exhibit A-15 (MA-7), Schedule E-3
[4] Exhibit A-15 (MA-7), Schedule E-3
[5] Exhibit A-15 (MA-7), Schedule E-3

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
General Large Service GS-3

Case No.: U-21806
Exhibit No.: A-16 (SAS-4)
Schedule: F-3
Page: 5 of 11
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Billing Determinants Units	(d) Present Rates	(e) Present Revenue	(f) Proposed Rates	(g) Proposed Revenue
				$/unit	$000	$/unit	$000
	Delivery						
1	Customer [1]	487	Mthly	324.50	$ 1,895	437.80	$ 2,556
2	Contiguous Account [2]	52	Mthly	80.00	50	125.00	78
3	Distribution Mcf/Mth [3]	8,183	MMcf	3.3012	27,013	3.3422	27,349
4	Total Delivery				28,958		29,983
	Fuel						
5	GCR Sales [4]	8,028	MMcf	3.2960	26,459	3.2960	26,459
6	Alternative Fuel Sales [5]	155	MMcf	-	-	-	-
7	Total Fuel	8,183			26,459		26,459
8	Total Service (Delivery & Fuel)				$ 55,417		$ 56,442

Notes

[1] Exhibit A-15 (MA-11), Schedule E-7
[2] Exhibit A-15 (MA-11), Schedule E-7
[3] Exhibit A-15 (MA-7), Schedule E-3
[4] Exhibit A-15 (MA-7), Schedule E-3
[5] Exhibit A-15 (MA-7), Schedule E-3

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
General Outdoor Lighting Service GL

Case No.: U-21806
Exhibit No.: A-16 (SAS-4)
Schedule: F-3
Page: 6 of 11
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Billing Determinants Quantity Present	(c) Billing Determinants Quantity Proposed	(d) Units	(e) Present Rates	(f) Present Revenue	(g) Proposed Rates	(h) Proposed Revenue [2]
					$/unit	$000	$/unit	$000
1	Single Mantle	-	-	Luminary	6.00	$ -	-	$ -
2	Multiple Mantle	-	-	Luminary	11.00	-	-	-
3	Total Service					$ -		$ -

Notes

	Single Mantle	Monthly Luminaires [1]	Annual Luminaires
4	2.5 cubic feet, or less, per hour	-	-
	Multiple Mantle		
5	2.5 - 4.5 cubic feet per hour	-	-
		-	-

		Single Mantle	Multiple Mantle
6	Average number of hours per month	730	730
7	Hourly rated capacity of fixtures in cf	2.5	4.5
8	Monthly consumption in cf	1,825	3,285
9	Monthly consumption in Mcf	1.825	3.285
10	Cost of gas per Mcf in this proceeding	$ 3.296	$ 3.296
11	Monthly gas cost per luminaire	$ 6.02	$ 10.83

Notes

[1] 2024 Street Lighting Report

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Test Year Present and Proposed Revenue Detail
Small Transport ST

Case No.: U-21806
Exhibit No.: A-16 (SAS-4)
Schedule: F-3
Page: 7 of 11
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units	(d) Present Rates	(e) Present Revenue	(f) Proposed Rates	(g) Proposed Revenue
				$/unit	$000	$/unit	$000
	Delivery						
1	Customer [1]	669	Mthly	973.32	$ 7,814	1,185.81	$ 9,520
2	Contiguous Account [2]	613	Mthly	60.00	441	105.00	772
3	Distribution Mcf/Mth [3]	18,679	MMcf	1.4273	26,661	1.9509	36,442
	Authorized Tolerance Level [4]						
4	2.0% ATL	23	MMcf	(0.0732)	(2)	(0.0781)	(2)
5	4.0% ATL	158	MMcf	(0.0507)	(8)	(0.0540)	(9)
6	6.5% ATL	1,715	MMcf	(0.0225)	(39)	(0.0240)	(41)
7	7.5% ATL	355	MMcf	(0.0113)	(4)	(0.0120)	(4)
8	8.5% ATL	16,429	MMcf	-	-	-	-
9	9.5% ATL	-	MMcf	0.0113	-	0.0120	-
10	10.5% ATL	-	MMcf	0.0225	-	0.0240	-
11	Total Delivery				$ 34,864		$ 46,678

Notes

[1] Exhibit A-15 (MA-11), Schedule E-7
[2] Exhibit A-15 (MA-11), Schedule E-7
[3] Exhibit A-15 (MA-7), Schedule E-3
[4] Exhibit A-15 (MA-8), Schedule E-4

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
Large Transport LT

Case No.: U-21806
Exhibit No.: A-16 (SAS-4)
Schedule: F-3
Page: 8 of 11
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Units	(d) Present Rates	(e) Present Revenue	(f) Proposed Rates	(g) Proposed Revenue
				$/unit	$000	$/unit	$000
	Delivery						
1	Customer [1]	101	Mthly	2,026.79	$ 2,448	4,631.70	$ 5,595
2	Contiguous Account [2]	258	Mthly	60.00	186	105.00	325
3	Distribution Mcf/Mth [3]	18,970	MMcf	1.3009	24,678	1.5374	29,165
	Authorized Tolerance Level [4]						
4	2.0% ATL	-	MMcf	(0.0732)	-	(0.0781)	-
5	4.0% ATL	962	MMcf	(0.0507)	(49)	(0.0540)	(52)
6	6.5% ATL	2,771	MMcf	(0.0225)	(62)	(0.0240)	(67)
7	7.5% ATL	193	MMcf	(0.0113)	(2)	(0.0120)	(2)
8	8.5% ATL	15,044	MMcf	-	-	-	-
9	9.5% ATL	-	MMcf	0.0113	-	0.0120	-
10	10.5% ATL	-	MMcf	0.0225	-	0.0240	-
11	Total Delivery				$ 27,199		$ 34,964

Notes

[1] Exhibit A-15 (MA-11), Schedule E-7
[2] Exhibit A-15 (MA-11), Schedule E-7
[3] Exhibit A-15 (MA-7), Schedule E-3
[4] Exhibit A-15 (MA-8), Schedule E-4

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
Extremely Large Transport XLT

Case No.: U-21806
Exhibit No.: A-16 (SAS-4)
Schedule: F-3
Page: 9 of 11
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Billing Determinants Units	(d) Present Rates	(e) Present Revenue	(f) Proposed Rates	(g) Proposed Revenue
				$/unit	$000	$/unit	$000
	Delivery						
1	Customer [1]	24	Mthly	16,379.74	$ 4,717	17,042.79	$ 4,908
2	Contiguous Account [2]	104	Mthly	60.00	$ 75	105.00	131
3	Remote Meters [3]	39	Mthly	70.00	$ 33	70.00	33
4	Distribution Mcf/Mth [4]	27,277	MMcf	0.9564	$ 26,088	1.2395	33,812
	Authorized Tolerance Level [5]						
5	2.0% ATL	3,967	MMcf	(0.0732)	$ (290)	(0.0781)	(310)
6	4.0% ATL	1,839	MMcf	(0.0507)	$ (93)	(0.0540)	(99)
7	6.5% ATL	13,925	MMcf	(0.0225)	$ (313)	(0.0240)	(335)
8	7.5% ATL	1,049	MMcf	(0.0113)	$ (12)	(0.0120)	(13)
9	8.5% ATL	6,497	MMcf	-	$ -	-	-
10	9.5% ATL	-	MMcf	0.0113	$ -	0.0120	-
11	10.5% ATL	-	MMcf	0.0225	$ -	0.0240	-
12	Total Delivery				$ 30,204		$ 38,128

Notes

[1] Exhibit A-15 (MA-11), Schedule E-7
[2] Exhibit A-15 (MA-11), Schedule E-7
[3] WP-SAS-3
[4] Exhibit A-15 (MA-7), Schedule E-3
[5] Exhibit A-15 (MA-8), Schedule E-4

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
Extra Extremely Large Transport XXLT

Case No.: U-21806
Exhibit No.: A-16 (SAS-4)
Schedule: F-3
Page: 10 of 11
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Billing Determinants Units	(d) Present Rates	(e) Present Revenue	(f) Proposed Rates	(g) Proposed Revenue
				$/unit	$000	$/unit	$000
	Delivery						
1	Customer [1]	3	Mthly	43,617.55	$ 1,570	41,396.85	$ 1,490
2	Remote Meters	3	Mthly	70.00	3	70.00	3
3	Distribution Mcf/Mth [2]	16,528	MMcf	0.5177	8,556	0.5278	8,723
	Authorized Tolerance Level [3]						
	2.0% ATL [4]	-	MMcf	(0.0225)	-	(0.0240)	-
4	Total Delivery				$ 10,129		$ 10,216

Notes

[1] Exhibit A-15 (MA-11), Schedule E-7
[2] Exhibit A-15 (MA-7), Schedule E-3
[3] Exhibit A-15 (MA-8), Schedule E-4
[4] Customers on XXLT are only eligible for the 2.0% ATL credit, less the 4.0% ATL credit because the 4.0% ATL credit is already included in the rate via the adjustment calculated on Exhibit A-108 (SAS-6).

Schedule F-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Present and Proposed Revenue Detail
Transmission Only Transportation Service Rate (TOT)

Case No.: U-21806
Exhibit No.: A-16 (SAS-4)
Schedule: F-3
Page: 11 of 11
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Billing Determinants Quantity	(c) Billing Determinants Units	(d) Present Rates	(e) Present Revenue	(f) Proposed Rates	(g) Proposed Revenue[1]
				$/unit	$000	$/unit	$000
	Delivery						
1	Rate STT Transmission Mcf/Mth (1)	90	MMcf	0.4533	41	0.7793	70
2	Rate STT Customer Charge	3	Mthly		-	208.22	7
4	Rate LTT Transmission Mcf/Mth (1)	165	MMcf	0.4533	75	0.6381	105
5	Rate LTT Customer Charge	2	Mthly		-	1,384.54	33
7	Rate XLTT Transmission Mcf/Mth (1)	-	MMcf	0.4533	-	0.6126	-
8	Rate XLTT Customer Charge	-	Mthly		-	2,447.53	-
10	Rate XXLTT Transmission Mcf/Mth (1)	-	MMcf	0.4533	-	0.3385	-
11	Rate XXLTT Customer Charge	-	Mthly		-	20,365.47	-
12	Total Delivery				$ 116		$ 216

Notes
(1) Revenue from this rate schedule is included in Other Gas Revenue

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills
Residential Single Family Dwelling A
(Excluding Income Assistance)

Case No.: U-21806
Exhibit No.: A-16 (SAS-5)
Schedule: F-4
Page: 1 of 5
Witness: SASmith
Date: December 2024

Line No.	(a) Monthly Use	(b) Present Net Monthly Bill	(c) Proposed Net Monthly Bill	(d) Increase Amount	(e) Increase Percent	(f) Proposed Unit Cost
	Mcf	$	$	$	%	$/Mcf
1	5	57.46	65.55	8.09	14.09	13.11
2	10	99.91	111.10	11.19	11.20	11.11
3	15	142.37	156.65	14.28	10.03	10.44
4	20	184.82	202.20	17.38	9.40	10.11
5	25	227.28	247.75	20.47	9.01	9.91
6	30	269.73	293.30	23.57	8.74	9.78
7	40	354.64	384.40	29.76	8.39	9.61

	Present	Proposed
Customer Charge ($/Mth)	15.00	20.00
Distribution Charge ($/Mcf)	5.1950	5.8140
GCR Factor ($/Mcf)	3.2960	3.2960

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills
Residential Single Family Dwelling A
(Including Income Assistance)

Case No.: U-21806
Exhibit No.: A-16 (SAS-5)
Schedule: F-4
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Witness: SASmith
Date: December 2024

Line No.	(a) Monthly Use	(b) Present Net Monthly Bill	(c) Proposed Net Monthly Bill	(d) Increase Amount	(e) Increase Percent	(f) Proposed Unit Cost
	Mcf	$	$	$	%	$/Mcf
8	5	42.46	45.55	3.09	7.29	9.11
9	10	84.91	91.10	6.19	7.29	9.11
10	15	127.37	136.65	9.28	7.29	9.11
11	20	169.82	182.20	12.38	7.29	9.11
12	25	212.28	227.75	15.47	7.29	9.11
13	30	254.73	273.30	18.57	7.29	9.11
14	40	339.64	364.40	24.76	7.29	9.11

	Present	Proposed
Customer Charge ($/Mth)	15.00	20.00
Income Assistance ($/Mth)	(15.00)	(20.00)
Distribution Charge ($/Mcf)	5.1950	5.8140
GCR Factor ($/Mcf)	3.2960	3.2960

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills
General Small Service GS-1

Case No.: U-21806
Exhibit No.: A-16 (SAS-5)
Schedule: F-4
Page: 3 of 5
Witness: SASmith
Date: December 2024

Line No.	(a) Monthly Use	(b) Present Net Monthly Bill	(c) Proposed Net Monthly Bill	(d) Increase Amount	(e) Increase Percent	(f) Proposed Unit Cost
	Mcf	$	$	$	%	$/Mcf
15	2	34.42	40.92	6.50	18.89	20.46
16	10	100.11	108.62	8.51	8.50	10.86
17	15	141.16	150.93	9.77	6.92	10.06
18	25	223.27	235.54	12.28	5.50	9.42
19	40	346.43	362.47	16.04	4.63	9.06
20	50	428.54	447.09	18.55	4.33	8.94
21	80	674.86	700.94	26.08	3.86	8.76

	Present	Proposed
Customer Charge ($/Mth)	18.00	24.00
Distribution Charge ($/Mcf)	4.9147	5.1657
GCR Factor ($/Mcf)	3.2960	3.2960

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills
General Medium Service GS-2

Case No.: U-21806
Exhibit No.: A-16 (SAS-5)
Schedule: F-4
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Witness: SASmith
Date: December 2024

Line No.	(a) Monthly Use	(b) Present Net Monthly Bill	(c) Proposed Net Monthly Bill	(d) Increase Amount	(e) Increase Percent	(f) Proposed Unit Cost
	Mcf	$	$	$	%	$/Mcf
22	100	815.98	845.57	29.59	3.63	8.46
23	200	1,498.64	1,544.31	45.67	3.05	7.72
24	500	3,546.62	3,640.53	93.91	2.65	7.28
25	600	4,229.28	4,339.27	109.99	2.60	7.23
26	700	4,911.94	5,038.01	126.07	2.57	7.20
27	800	5,594.60	5,736.75	142.15	2.54	7.17
28	1000	6,959.92	7,134.23	174.31	2.50	7.13

	Present	Proposed
Customer Charge ($/Mth)	133.32	146.83
Distribution Charge ($/Mcf)	3.5306	3.6914
GCR Factor ($/Mcf)	3.2960	3.2960

Schedule F-4

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Comparison of Present and Proposed Monthly Bills
General Large Service GS-3

Case No.: U-21806
Exhibit No.: A-16 (SAS-5)
Schedule: F-4
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Witness: SASmith
Date: December 2024

Line No.	(a) Monthly Use	(b) Present Net Monthly Bill	(c) Proposed Net Monthly Bill	(d) Increase Amount	(e) Increase Percent	(f) Proposed Unit Cost
	Mcf	$	$	$	%	$/Mcf
29	100	984.22	1,101.62	117.40	11.93	11.02
30	200	1,643.94	1,765.45	121.51	7.39	8.83
31	500	3,623.10	3,756.92	133.82	3.69	7.51
32	600	4,282.82	4,420.75	137.93	3.22	7.37
33	700	4,942.54	5,084.57	142.03	2.87	7.26
34	800	5,602.26	5,748.40	146.14	2.61	7.19
35	1000	6,921.70	7,076.05	154.35	2.23	7.08

	Present	Proposed
Customer Charge ($/Mth)	324.50	437.80
Distribution Charge ($/Mcf)	3.3012	3.3422
GCR Factor ($/Mcf)	3.2960	3.2960

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
Projected 12 Month Period: November 2025-October 2026
($000)

Schedule F-1

Case No.: U-21806
Exhibit No.: A-16 (SMG-1)
Schedule: F-1
Page: 1 of 16
Witness: SMGeller
Date: December 2024

Line. No.	(a) Summary Description	(b) Classification	(c) Allocation	(d) Total	(e) Residential	(f) Rate GS-1	(g) Rate GS-2	(h) Rate GS-3	(i) Rate ST	(j) Rate LT	(k) Rate XLT	(l) Rate XXLT
1	Service Revenue			2,284,471	1,631,131	271,029	224,497	55,417	34,864	27,199	30,204	10,129
2	Other Revenue			28,666	19,150	3,366	3,062	774	685	570	794	265
3	Total Revenue			2,313,137	1,650,281	274,396	227,559	56,191	35,549	27,769	30,998	10,394
4	Expenses:											
5	Cost of Gas Sold (COGS)			737,588	520,137	98,061	92,931	26,459	-	-	-	-
6	O & M Expense			297,904	228,425	29,195	18,284	4,097	6,528	4,760	5,102	1,513
10	Depreciation & Amortization Expense			384,404	277,312	40,494	29,856	6,873	10,500	7,921	8,794	2,654
14	Lost and Unaccounted for (LAUF) Gas			12,709	8,962	1,690	1,601	456	-	-	-	-
18	Taxes			330,836	235,504	36,871	28,450	6,342	8,053	6,268	7,039	2,310
22	Company Use			5,502	3,880	731	693	197	-	-	-	-
26	Total Expenses			1,768,943	1,274,222	207,043	171,815	44,425	25,081	18,948	20,935	6,476
27	Net Operating Income			544,194	376,060	67,353	55,744	11,766	10,468	8,821	10,064	3,918
28	Test Year AFUDC	CWIP	207	1,298	866	149	133	32	37	30	39	12
32	Adjusted Net Operating Income			545,491	376,926	67,502	55,877	11,798	10,505	8,851	10,103	3,930
33	Total Rate Base			11,750,739	8,350,140	1,257,448	969,000	226,813	322,796	247,579	288,749	88,215
37	Return on Rate Base @ 6.22%			730,837.85	519,337	78,207	60,267	14,107	20,076	15,398	17,959	5,487
41	Income Deficiency/(Sufficiency)			185,346	142,411	10,705	4,390	2,308	9,571	6,547	7,856	1,557
42	Revenue Deficiency/(Sufficiency)			248,008	190,558	14,324	5,875	3,089	12,807	8,761	10,512	2,083
43	Rev Requirement/Total Cost of Service			$ 2,561,146	$ 1,840,839	$ 288,720	$ 233,433	$ 59,280	$ 48,356	$ 36,530	$ 41,510	$ 12,477
44	Less: Cost of Gas Sold (Test Yr)			737,588	520,137	98,061	92,931	26,459	-	-	-	-
45	Less: Miscellaneous Revenue (TY)			28,666	19,150	3,366	3,062	774	685	570	794	265
46	**Proposed Rate Design Revenue**			**1,794,891**	**1,301,551**	**187,292**	**137,441**	**32,047**	**47,671**	**35,960**	**40,716**	**12,212**
47	Customer			657,851	541,913	60,023	27,302	5,645	9,570	6,043	5,702	1,652
48	Demand			1,061,748	700,877	119,636	105,793	25,390	36,818	28,974	34,001	10,260
49	Energy			75,293	58,761	7,634	4,346	1,012	1,282	943	1,013	302

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
Projected 12 Month Period: November 2025-October 2026
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Schedule F-1

Case No.: U-21806
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Witness: SMGeller
Date: December 2024

Line. No.	(a) Summary Description	(b) Classification	(c) Allocation	(d) Total	(e) Residential	(f) Rate GS-1	(g) Rate GS-2	(h) Rate GS-3	(i) Rate ST	(j) Rate LT	(k) Rate XLT	(l) Rate XXLT
	Proposed Rate Design Revenue Summary											
1	Transmission Related Cost			418,481	256,257	48,839	47,401	11,757	15,572	13,198	19,074	6,383
2	Customer			45,661	$ 27,804	$ 5,451	$ 5,325	$ 1,289	$ 1,625	$ 1,411	$ 2,043	$ 711
3	Demand			362,500	$ 222,021	$ 42,158	$ 40,884	$ 10,168	$ 13,614	$ 11,503	$ 16,620	$ 5,533
4	Energy			10,321	$ 6,432	$ 1,230	$ 1,191	$ 300	$ 333	$ 284	$ 411	$ 139
5	Storage Related Cost			259,336	166,422	31,690	30,922	7,858	6,690	5,512	7,964	2,280
6	Customer			26,274	$ 16,759	$ 3,263	$ 3,224	$ 802	$ 645	$ 546	$ 794	$ 241
7	Demand			226,266	$ 145,278	$ 27,591	$ 26,881	$ 6,847	$ 5,881	$ 4,831	$ 6,974	$ 1,982
8	Energy			6,796	$ 4,385	$ 837	$ 816	$ 208	$ 163	$ 135	$ 195	$ 56
9	Distribution Related Cost			1,117,074	878,872	106,763	59,119	12,432	25,409	17,250	13,679	3,550
10	Customer			585,916	$ 497,350	$ 51,309	$ 18,752	$ 3,554	$ 7,300	$ 4,086	$ 2,865	$ 700
11	Demand			472,983	$ 333,578	$ 49,887	$ 38,028	$ 8,375	$ 17,323	$ 12,639	$ 10,407	$ 2,745
12	Energy			58,176	$ 47,944	$ 5,568	$ 2,339	$ 503	$ 786	$ 524	$ 407	$ 106
13	Total			1,794,891	1,301,551	187,292	137,441	32,047	47,671	35,960	40,716	12,212
14	Customer			657,851	541,913	60,023	27,302	5,645	9,570	6,043	5,702	1,652
15	Demand			1,061,748	700,877	119,636	105,793	25,390	36,818	28,974	34,001	10,260
16	Energy			75,293	58,761	7,634	4,346	1,012	1,282	943	1,013	302
17	Mcf Thruput			307,735,810	157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
18	Customer Count			1,846,892	1,709,595	119,353	15,633	539	1,282	359	128	3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
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Schedule F-1

Case No.: U-21806
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Witness: SMGeller
Date: December 2024

Line. No.	(a) Summary Description	(b) Classification	(c) Allocation	(d) Total	(e) Residential	(f) Rate GS-1	(g) Rate GS-2	(h) Rate GS-3	(i) Rate ST	(j) Rate LT	(k) Rate XLT	(l) Rate XXLT
1	Production Plant	DEMAND	102	122,449	86,350	16,279	15,428	4,393	-	-	-	-
5	Storage Plant	DEMAND	107	1,638,445	1,044,143	200,068	196,208	49,246	44,068	36,520	52,852	15,340
9	Transmission To/From Storage	DEMAND	107	1,789,747	1,140,564	218,543	214,326	53,794	48,137	39,892	57,733	16,757
13	Other Transmission	DEMAND	104	1,533,933	883,487	170,419	164,156	39,037	77,306	67,070	96,913	35,545
17	Total Transmission Plant			3,323,679	2,024,051	388,962	378,482	92,831	125,443	106,963	154,646	52,302
21	Distribution Plant - Other	DEMAND	105	746,971	422,924	82,172	79,214	19,105	37,744	33,725	52,666	19,421
25	Distribution Plant - Other - Fee Land & Easements (374)	DEMAND	104	-	-	-	-	-	-	-	-	-
29	Distribution Plant - Other - Structures and Improvements (375)	DEMAND	104	-	-	-	-	-	-	-	-	-
33	Distribution Plant - Other - Compressor Station Equipment (377)	DEMAND	104	-	-	-	-	-	-	-	-	-
37	Distribution Plant - Other - M & R General (378)	DEMAND	104	-	-	-	-	-	-	-	-	-
41	Distribution Plant - Other - Meter Installations (382)	CUST	108	-	-	-	-	-	-	-	-	-
45	Mains - High Pressure Capable	DEMAND	105	361,922	204,915	39,814	38,381	9,257	18,288	16,340	25,518	9,410
49	Mains - Non-High Pressure Capable	DEMAND	106	2,374,696	1,530,422	283,011	271,456	59,375	118,618	81,363	30,440	11
53	Services & Meters	CUST	108	5,195,287	4,581,613	446,505	106,613	17,077	31,361	9,385	2,637	96
57	Total Distribution Plant			8,678,876	6,739,874	851,502	495,664	104,814	206,010	140,813	111,260	28,938
61	Total Plant In Service excl Gen, Com, & Int			13,763,449	9,894,418	1,456,811	1,085,781	251,284	375,521	284,296	318,758	96,580
65	Gen, Com, & Int Plant and PHFFU	PLANT	206	820,939	590,165	86,893	64,763	14,988	22,398	16,957	19,013	5,761
69	Total Test Year Plant in Service			14,584,387	10,484,583	1,543,705	1,150,544	266,272	397,919	301,253	337,771	102,341

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
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Line. No.	(a) Summary Description	(b) Classification	(c) Allocation	(d) Total	(e) Residential	(f) Rate GS-1	(g) Rate GS-2	(h) Rate GS-3	(i) Rate ST	(j) Rate LT	(k) Rate XLT	(l) Rate XXLT
1	Production CWIP	PROD_PLANT	202	-	-	-	-	-	-	-	-	-
5	Storage CWIP	STOR_PLANT	107	161,299	102,792	19,696	19,316	4,848	4,338	3,595	5,203	1,510
9	Transmission CWIP	TRAN_PLANT	204	53,976	32,870	6,317	6,146	1,508	2,037	1,737	2,511	849
13	Distribution CWIP	DIST_PLANT	205	42,995	33,390	4,218	2,456	519	1,021	698	551	143
17	General, Common & Intangible and PHFFU CWIP	PLANT	206	64,606	46,445	6,838	5,097	1,180	1,763	1,334	1,496	453
21	Total CWIP			322,877	215,497	37,069	33,015	8,054	9,159	7,364	9,762	2,956
25	Production Accumulated Depreciation	PROD_PLANT	202	(8,245)	(5,814)	(1,096)	(1,039)	(296)	-	-	-	-
29	Storage Accumulated Depreciation	STOR_PLANT	107	(253,855)	(161,776)	(30,998)	(30,400)	(7,630)	(6,828)	(5,658)	(8,189)	(2,377)
33	Transmission Accumulated Depreciation	TRAN_PLANT	204	(615,340)	(374,729)	(72,012)	(70,072)	(17,187)	(23,224)	(19,803)	(28,631)	(9,683)
37	Distribution Accumulated Depreciation	DIST_PLANT	205	(3,209,490)	(2,492,438)	(314,890)	(183,299)	(38,761)	(76,183)	(52,073)	(41,145)	(10,701)
41	General, Common & Intangible and PHFFU Accumulated Depreciation	PLANT	206	(578,782)	(416,081)	(61,262)	(45,659)	(10,567)	(15,791)	(11,955)	(13,404)	(4,061)
45	Total Accumulated Depreciation			(4,665,713)	(3,450,839)	(480,257)	(330,468)	(74,440)	(122,027)	(89,490)	(91,369)	(26,823)
49	Cash & Cash Equivalents	ENERGY	209	696,014	529,462	68,012	44,589	10,010	16,090	11,700	12,465	3,687
53	Accounts Receivable	ENERGY	111	109,689	78,319	13,014	10,779	2,661	1,674	1,306	1,450	486
57	Materials and Supplies	O&M (EXC. A&G)	209	55,983	42,586	5,470	3,586	805	1,294	941	1,003	297

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Consumers Energy Company
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Schedule F-1

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Date: December 2024

Line. No.	(a) Summary Description	(b) Classification	(c) Allocation	(d) Total	(e) Residential	(f) Rate GS-1	(g) Rate GS-2	(h) Rate GS-3	(i) Rate ST	(j) Rate LT	(k) Rate XLT	(l) Rate XXLT
1	Gas Stored Underground- Recoverable Base Gas	STOR_PLANT	107	173,941	110,849	21,240	20,830	5,228	4,678	3,877	5,611	1,629
5	Gas Stored Underground- Working Gas	STOR_PLANT	102	208,094	146,745	27,666	26,218	7,465	-	-	-	-
9	Real & Personal Property Taxes	PLANT	206	176,164	126,643	18,646	13,897	3,216	4,806	3,639	4,080	1,236
13	Other Assets	PLANT	206	-	-	-	-	-	-	-	-	-
17	Deferred Debits	PLANT	206	466,865	335,625	49,416	36,830	8,524	12,738	9,643	10,812	3,276
21	Total Assets			1,886,750	1,370,228	203,463	156,730	37,909	41,280	31,107	35,421	10,611
25	Accounts Payable	ENERGY	102	234,904	165,651	31,230	29,596	8,427	-	-	-	-
29	Dividends Declared	PLANT	215	14,780	10,226	1,822	1,506	318	286	241	275	107
33	Customer Deposits	ENERGY	111	11,793	8,913	1,329	962	234	156	105	74	19
37	Accrued Interest	PLANT	206	42,561	30,596	4,505	3,358	777	1,161	879	986	299
41	Accrued Taxes - Federal	PLANT	215	771	534	95	79	17	15	13	14	6
45	Accrued Taxes - State	PLANT	215	(98)	(68)	(12)	(10)	(2)	(2)	(2)	(2)	(1)
49	Accrued Taxes - R&PP Tax & Other	PLANT	206	11,726	8,430	1,241	925	214	320	242	272	82
53	Other Liabilities	PLANT	206	30,215	21,722	3,198	2,384	552	824	624	700	212

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Line. No.	(a) Summary Description	(b) Classification	(c) Allocation	(d) Total	(e) Residential	(f) Rate GS-1	(g) Rate GS-2	(h) Rate GS-3	(i) Rate ST	(j) Rate LT	(k) Rate XLT	(l) Rate XXLT
1	Deferred Credits	PLANT	206	31,718	22,802	3,357	2,502	579	865	655	735	223
5	Total Liabilities			378,369	268,805	46,765	41,301	11,115	3,626	2,757	3,054	946
9	Total Working Capital			1,508,380	1,101,423	156,698	115,429	26,794	37,654	28,350	32,368	9,664
13	Test Year Unamortized MGP Expense - Net	PLANT	206	19,967	14,354	2,113	1,575	365	545	412	462	140
17	Test Year Retainers & Customer Advances-Net	DIST_PLANT	205	(19,159)	(14,879)	(1,880)	(1,094)	(231)	(455)	(311)	(246)	(64)
21	Adjustments to Rate Base			808	(525)	234	481	133	90	102	217	76
25	Total Test Year Rate Base			11,750,739	8,350,140	1,257,448	969,000	226,813	322,796	247,579	288,749	88,215
29	Production O&M	PROD_PLANT	202	-	-	-	-	-	-	-	-	-
33	Storage O&M	STOR_PLANT	107	25,567	16,293	3,122	3,062	768	688	570	825	239
37	Transmission O&M	TRAN_PLANT	204	36,635	22,310	4,287	4,172	1,023	1,383	1,179	1,705	576
41	Distribution O&M	DIST_PLANT	205	136,688	106,150	13,411	7,806	1,651	3,245	2,218	1,752	456
45	Customer Accounting O&M	CUST	110	39,076	35,903	2,507	328	11	236	71	20	1
49	Customer Service & Information O&M	CUST	109	421	390	27	4	0	0	0	0	0
53	Customer Assistance O&M	CUST	109	1,799	1,666	116	15	1	1	0	0	0

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Line. No.	(a) Summary Description	(b) Classification	(c) Allocation	(d) Total	(e) Residential	(f) Rate GS-1	(g) Rate GS-2	(h) Rate GS-3	(i) Rate ST	(j) Rate LT	(k) Rate XLT	(l) Rate XXLT
1	Total Test Year O&M Expense			240,186	182,711	23,470	15,387	3,454	5,552	4,038	4,302	1,272
2	Customer			123,120	101,501	10,678	5,020	1,000	2,180	1,399	1,069	274
3	Demand			117,066	81,210	12,792	10,367	2,454	3,373	2,639	3,233	999
4	Energy			-	-	-	-	-	-	-	-	-
5	Administrative & General Expense	O&M (EXC. A&G)	209	82,571	62,812	8,069	5,290	1,188	1,909	1,388	1,479	437
6	Customer		209	42,326	32,198	4,136	2,712	609	978	712	758	224
7	Demand		209	40,245	30,615	3,933	2,578	579	930	677	721	213
8	Energy		209	-	-	-	-	-	-	-	-	-
9	Business Customer Care	CUST	114	-	-	-	-	-	-	-	-	-
13	Customer Contact Center	CUST	115	-	-	-	-	-	-	-	-	-
17	Interest on Customer Deposits	ENERGY	111	237	179	27	19	5	3	2	1	0
21	Test Year Uncollectible Expense	ENERGY	113	15,327	13,649	1,569	101	9	(3)	2	-	-
25		ENERGY	209	-	-	-	-	-	-	-	-	-
29	Production- Pension & Benefits Expense	PROD_PLANT	202	-	-	-	-	-	-	-	-	-
33	Storage- Pension & Benefits Expense	STOR_PLANT	107	(2,414)	(1,538)	(295)	(289)	(73)	(65)	(54)	(78)	(23)
37	Transmission- Pension & Benefits Expense	TRAN_PLANT	204	(3,766)	(2,294)	(441)	(429)	(105)	(142)	(121)	(175)	(59)
41	Distribution- Pension & Benefits Expense	DIST_PLANT	205	(21,341)	(16,573)	(2,094)	(1,219)	(258)	(507)	(346)	(274)	(71)
45	Customer Accounting (Billing)- Pension & Benefits Expense	CUST	110	(4,264)	(3,918)	(274)	(36)	(1)	(26)	(8)	(2)	(0)
49	Customer Service- Pension & Benefits Expense	CUST	109	(221)	(205)	(14)	(2)	(0)	(0)	(0)	(0)	(0)
53	Sales Expense- Pension & Benefits Expense	O&M (EXC. A&G)	209	(10)	(8)	(1)	(0)	(0)	(0)	(0)	(0)	(0)
57	Administrative & General- Pension & Benefits Expense	CUST	209	(8,400)	(6,390)	(821)	(538)	(121)	(194)	(141)	(150)	(44)
61	Total Test Year Pension & Benefits Expense			(40,418)	(30,927)	(3,939)	(2,513)	(558)	(934)	(670)	(679)	(198)
65	Production- Payroll Tax	PROD_PLANT	202	-	-	-	-	-	-	-	-	-

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Line. No.	(a) Summary Description	(b) Classification	(c) Allocation	(d) Total	(e) Residential	(f) Rate GS-1	(g) Rate GS-2	(h) Rate GS-3	(i) Rate ST	(j) Rate LT	(k) Rate XLT	(l) Rate XXLT
1	Storage- Payroll Tax	STOR_PLANT	107	876	558	107	105	26	24	20	28	8
5	Transmission- Payroll Tax	TRAN_PLANT	204	1,367	832	160	156	38	52	44	64	22
9	Distribution- Payroll Tax	DIST_PLANT	205	7,744	6,014	760	442	94	184	126	99	26
13	Customer Accounting (Billing)- Payroll Tax	CUST	110	1,547	1,422	99	13	0	9	3	1	0
17	Customer Service- Payroll Tax	CUST	109	80	74	5	1	0	0	0	0	0
21	Sales Expense- Payroll Tax	O&M (EXC. A&G)	209	4	3	0	0	0	0	0	0	0
25	Administrative & General- Payroll Tax	CUST	209	3,048	2,319	298	195	44	70	51	55	16
29	Total Payroll Tax			14,666	11,222	1,429	912	202	339	243	247	72
33	Production- Depreciation & Amortization Exp	PROD_PLANT	202	-	-	-	-	-	-	-	-	-
37	Storage- Depreciation & Amortization Exp	STOR_PLANT	107	39,352	25,078	4,805	4,713	1,183	1,058	877	1,269	368
41	Transmission- Depreciation & Amortization Exp	TRAN_PLANT	204	76,856	46,804	8,994	8,752	2,147	2,901	2,473	3,576	1,209
45	Distribution- Depreciation & Amortization Exp	DIST_PLANT	205	218,868	169,969	21,474	12,500	2,643	5,195	3,551	2,806	730
49	Gen, Com, & Int- Depreciation & Amortization Exp	PLANT	206	49,327	35,461	5,221	3,891	901	1,346	1,019	1,142	346
53	Test Year Total Depreciation & Amortization Exp			384,404	277,312	40,494	29,856	6,873	10,500	7,921	8,794	2,654

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1	Test Year Lost and Unaccounted for (LAUF) Gas	ENERGY	102	12,709	8,962	1,690	1,601	456	-	-	-	-
5	Test Year Company Use	ENERGY	102	5,502	3,880	731	693	197	-	-	-	-
9	Test Year Property Taxes	PLANT	206	201,200	144,641	21,296	15,872	3,673	5,490	4,156	4,660	1,412
13	Test Year Federal, State & City Income Tax	PLANT	215	111,893	77,415	13,792	11,399	2,410	2,165	1,821	2,082	808
17	TCJA Amortization	PLANT	208	(2,042)	(1,451)	(219)	(168)	(39)	(56)	(43)	(50)	(15)
21		PLANT	208	-	-	-	-	-	-	-	-	-
25	Test Year Miscellaneous Taxes	ENERGY	112	5,119	3,677	572	434	95	116	90	100	34
29	Total Test Year Other Taxes			316,170	224,282	35,442	27,538	6,140	7,714	6,025	6,792	2,238
33	Total Test Year Expenses Excluding COGS & Company Use			1,025,616	750,025	108,223	78,172	17,764	25,078	18,946	20,933	6,476
34	Customer			416,142	319,080	41,296	26,082	5,636	9,311	6,633	6,262	1,842
35	Demand			576,319	404,657	63,097	49,953	11,567	15,654	12,220	14,571	4,600
36	Energy			33,155	26,288	3,830	2,137	560	113	93	100	34
37	Test Year Cost of Gas Sold (COGS)			737,588	520,137	98,061	92,931	26,459	-	-	-	-

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Line. No.	(a) Summary Description	(b) Classification	(c) Allocation	(d) Total	(e) Residential	(f) Rate GS-1	(g) Rate GS-2	(h) Rate GS-3	(i) Rate ST	(j) Rate LT	(k) Rate XLT	(l) Rate XXLT
1	Test Year Service Revenue Including Cost of Gas Sold			2,284,471	1,631,131	271,029	224,497	55,417	34,864	27,199	30,204	10,129
	Other Revenues											
2	Forfeited Discounts (Late Payment Charge)		111	6,322	4,514	750	621	153	96	75	84	28
3	Misc Service Rev (ASP)		102	1,356	956	180	171	49	-	-	-	-
4	Rev from Transmission of Gas of Others		204	13,448	8,189	1,574	1,531	376	508	433	626	212
5	Rent from Gas Property		204	290	176	34	33	8	11	9	13	5
6	Joint Commodities Mrkt Agrmt Rev		102	-	-	-	-	-	-	-	-	-
7	GCR related charges to Transport Customers		102	3,421	2,413	455	431	123	-	-	-	-
8	Gas Merchant-Buy/sell Contracts		107	-	-	-	-	-	-	-	-	-
9	Rev from Storage Agrmts (GM, MCV & others)		107	1,905	1,214	233	228	57	51	42	61	18
10	Administrative Customer Acctg charges for GCC		110	1,487	1,366	95	12	0	9	3	1	0
11	Interest on Cash Operating Accounts		209	358	264	36	26	6	9	7	8	2
12	Miscellaneous		111	81	58	10	8	2	1	1	1	0
13	Total Other Test Year Revenues			28,666	19,150	3,366	3,062	774	685	570	794	265
14	Total Test Year Revenues			2,313,137	1,650,281	274,396	227,559	56,191	35,549	27,769	30,998	10,394

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Functionalization Factors

	1	2	3	4	5
Description	**Source**	**Factor**	**Total System**	**Distribution**	**Transmission**	**Storage**
CWIP			322,877	83,734	70,152	168,990
	INTERNAL- Input Line 52	CWIP		25.9%	21.7%	52.3%
Distribution			1	1	0	0
	N/A	DIST		100.0%	0.0%	0.0%
O&M Expense			240,186	$ 177,984	$ 36,635	$ 25,567
	INTERNAL- Input Line 90	O&M		74.1%	15.3%	10.6%
O&M/Plant in Service		-	-	-	-	
	INTERNAL- 50/50 Weighting of O&M & PIS	O&M/PIS		68.6%	20.1%	11.3%
Plant in Service			13,763,449	$ 8,678,876	$ 3,446,129	$ 1,638,445
	INTERNAL- Input Line 44	PIS		63.1%	25.0%	11.9%
Rate Base			11,750,739	$ 6,489,206	$ 3,167,656	$ 2,093,877
	INTERNAL- Input Line 82	RB		55.2%	27.0%	17.8%
Total Revenue			2,284,471	1,429,647	534,788	320,036
	INTERNAL- Input Line 34	REV		62.6%	23.4%	14.0%
Storage			1	-	-	1
	N/A	STOR		0.0%	0.0%	100.0%
Taxable Income			654,045	347,608	175,026	131,411
	INTERNAL- Input- Summary & Expense	TAXABLEINC		53.1%	26.8%	20.1%
Transmission			1	-	1	-
	N/A	TRAN		0.0%	100.0%	0.0%

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Classification Factors

Description	Source	Factor	1 Total System	2	3 Customer	4 Demand	5 Energy
Demand	N/A	DEMAND		1	0 0%	1 100%	0 0%
Customer	N/A	CUST		1	1 100%	0 0%	0 0%
Energy/Commodity	N/A	ENERGY		1	0 0%	0 0%	1 100%
Total Plant (exc. General, Common & Intangible Plant)	INTERNAL-Total COSS, Page 3 of 16, Line 61	PLANT		13,763,449	5,195,287 38%	8,568,162 62%	- 0%
Transmission Plant	INTERNAL- Total COSS, Page 3 of 16, Line 17	TRAN_PLANT		3,323,679	- 0%	3,323,679 100%	- 0%
Distribution Plant	INTERNAL- Total COSS, Page 3 of 16, Line 57	DIST_PLANT		8,678,876	5,195,287 59.86%	3,483,589 40.14%	- 0%
Production Plant	INTERNAL- Total COSS, Page 3 of 16, Line 1	PROD_PLANT		122,449	- 0%	122,449 100%	- 0%
Storage Plant	INTERNAL- Total COSS, Page 3 of 16, Line 5	STOR_PLANT		1,638,445	- 0%	1,638,445 100%	- 0%
Distribution Mains	N/A	DIST_MAIN		-	- 0%	- 0%	- 0%
O&M Expense	INTERNAL- Total COSS, Page 7 of 16, Line 1	O&M (EXC. A&G)		240,186	123,120 51%	117,066 49%	- 0%
CWIP	INTERNAL- Total COSS, Page 4 of 16, Line 21	CWIP		322,877	50,125 16%	272,752 84%	- 0%

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Allocation Factors- Total System

	1	2	3	4	5	6	7	8	9	10	11
Description / **Source**	**Factor**	**Total System**		**Residential**	**Rate GS-1**	**Rate GS-2**	**Rate GS-3**	**Rate ST**	**Rate LT**	**Rate XLT**	**Rate XXLT**
Total Annual Throughput		307,735,810		157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
WP-SMG-9	101			51.33%	9.73%	9.81%	2.66%	6.07%	6.16%	8.86%	5.37%
GCR Throughput		223,782,881		157,808,704	29,751,571	28,194,984	8,027,623	0	0	0	0
WP-SMG-9	102			70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
Transportation Throughput		83,952,929		141,259	197,217	2,004,585	155,218	18,679,317	18,970,211	27,277,483	16,527,639
WP-SMG-9	103			0.17%	0.23%	2.39%	0.18%	22.25%	22.60%	32.49%	19.69%
Average & Peak (Transmission)		1.0000		0.5760	0.1111	0.1070	0.0254	0.0504	0.0437	0.0632	0.0232
WP-SMG-9	104			57.60%	11.11%	10.70%	2.54%	5.04%	4.37%	6.32%	2.32%
Average & Peak (High Pressure)		1.0000		0.5662	0.1100	0.1060	0.0256	0.0505	0.0451	0.0705	0.0260
WP-SMG-10	105			56.62%	11.00%	10.60%	2.56%	5.05%	4.51%	7.05%	2.60%
Average & Peak (Non-High Pressure)		1.0000		0.6445	0.1192	0.1143	0.0250	0.0500	0.0343	0.0128	0.0000
WP-SMG-10	106			64.45%	11.92%	11.43%	2.50%	5.00%	3.43%	1.28%	0.00%
Average & Peak (50% Storage 50% Peak Month)		1.0000		0.6373	0.1221	0.1198	0.0301	0.0269	0.0223	0.0323	0.0094
WP-SMG-11	107			63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
Weighted Customer		1,938,583		1,709,595	166,610	39,782	6,372	11,702	3,502	984	36
WP-SMG-16	108			88.19%	8.59%	2.05%	0.33%	0.60%	0.18%	0.05%	0.00%
Average Number of Customers		1,846,892		1,709,595	119,353	15,633	539	1,282	359	128	3
WP-SMG-16	109			92.57%	6.46%	0.85%	0.03%	0.07%	0.02%	0.01%	0.00%
Weighted/Average Customer		1.0000		0.9188	0.0641	0.0084	0.0003	0.0060	0.0018	0.0005	0.0000
WP-SMG-16	110			91.88%	6.41%	0.84%	0.03%	0.60%	0.18%	0.05%	0.00%
Present Total Revenue (Including COGS)		2,284,471		1,631,131	271,029	224,497	55,417	34,864	27,199	30,204	10,129
Exhibit A-16 (SAS-1), Sch F-2	111	100%		71.40%	11.86%	9.83%	2.43%	1.53%	1.19%	1.32%	0.44%
Present Delivery Revenue (Excluding COGS)		1,546,883		1,110,994	172,968	131,566	28,958	34,864	27,199	30,204	10,129
Exhibit A-16 (SAS-1), Sch F-2	112	100%		71.82%	11.18%	8.51%	1.87%	2.25%	1.76%	1.95%	0.65%
Net Write Off		1.00		0.8905	0.1023	0.0066	0.0006	(0.0002)	0.0001	0.0000	0.0000
WP-SMG-22	113			89.05%	10.23%	0.66%	0.06%	-0.02%	0.01%	0.00%	0.00%
BCC		1.00		0.0000	0.7751	0.1960	0.0068	0.0156	0.0047	0.0017	0.0000
WP-SMG-25	114			0.00%	77.51%	19.60%	0.68%	1.56%	0.47%	0.17%	0.00%
CCC		1.00		0.9655	0.0341	0.0004	0.0000	0.0001	0.0000	0.0000	0.0000
WP-SMG-25	115			96.55%	3.41%	0.04%	0.00%	0.01%	0.00%	0.00%	0.00%
Total Revenue		2,313,137		1,650,281	274,396	227,559	56,191	35,549	27,769	30,998	10,394
INTERNAL- COSS PAGE 1, Line 3	201			71.34%	11.86%	9.84%	2.43%	1.54%	1.20%	1.34%	0.45%
Total Production Plant		122,449		86,350	16,279	15,428	4,393	-	-	-	-
INTERNAL- Total COSS, Page 3 of 16, Line 1	202			70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
Total Transmission Plant		3,323,679		2,024,051	388,962	378,482	92,831	125,443	106,963	154,646	52,302
INTERNAL- Total COSS, Page 3 of 16, Line 17	204			60.90%	11.70%	11.39%	2.79%	3.77%	3.22%	4.65%	1.57%
Total Distribution Plant		8,678,876		6,739,874	851,502	495,664	104,814	206,010	140,813	111,260	28,938
INTERNAL- Total COSS, Page 3 of 16, Line 57	205			77.66%	9.81%	5.71%	1.21%	2.37%	1.62%	1.28%	0.33%
Total Plant in Service (excluding Gen, Com & Int)		13,763,449		9,894,418	1,456,811	1,085,781	251,284	375,521	284,296	318,758	96,580
INTERNAL- COSS PAGE 3, Line 61	206			71.89%	10.58%	7.89%	1.83%	2.73%	2.07%	2.32%	0.70%
Total CWIP		322,877		215,497	37,069	33,015	8,054	9,159	7,364	9,762	2,956
INTERNAL- COSS PAGE 4, Line 21	207			66.74%	11.48%	10.23%	2.49%	2.84%	2.28%	3.02%	0.92%
Rate Base		11,750,739		8,350,140	1,257,448	969,000	226,813	322,796	247,579	288,749	88,215
INTERNAL- COSS PAGE 6, Line 25	208			71.06%	10.70%	8.25%	1.93%	2.75%	2.11%	2.46%	0.75%
Total O&M (excluding Admin & General)		240,186		182,711	23,470	15,387	3,454	5,552	4,038	4,302	1,272
INTERNAL- COSS PAGE 7, Line 1,9,13	209			76.07%	9.77%	6.41%	1.44%	2.31%	1.68%	1.79%	0.53%
Total O&M Expense		240,186		182,711	23,470	15,387	3,454	5,552	4,038	4,302	1,272
INTERNAL- COSS PAGE 7, Line 1,9,13	214			76.07%	9.77%	6.41%	1.44%	2.31%	1.68%	1.79%	0.53%
Pretax Net Operating Income		668,711		463,247	82,356	67,887	14,339	12,916	10,843	12,342	4,782
INTERNAL- COSS (Multiple Pages & Lines)	215			69.27%	12.32%	10.15%	2.14%	1.93%	1.62%	1.85%	0.72%
Total Depreciation & Amortization		384,404		277,312	40,494	29,856	6,873	10,500	7,921	8,794	2,654
INTERNAL- COSS PAGE 8, Line 53	216			72.14%	10.53%	7.77%	1.79%	2.73%	2.06%	2.29%	0.69%
Weighted HP and Non HP Plant		1.00		0.6341	0.1180	0.1132	0.0251	0.0500	0.0357	0.0204	0.0034
WP-SMG-24	217			63.41%	11.80%	11.32%	2.51%	5.00%	3.57%	2.04%	0.34%

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Allocation Factors- Transmission System

		4	5	6	7	8	9	10	11
	Factor	Transmission System	Residential	Rate GS-1	Rate GS-2	Rate GS-3	Rate ST	Rate LT	Rate XLT	Rate XXLT
		307,735,810	157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
101		100%	51.33%	9.73%	9.81%	2.66%	6.07%	6.16%	8.86%	5.37%
		223,782,881	157,808,704	29,751,571	28,194,984	8,027,623	0	0	0	0
102		100%	70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
		83,952,929	141,259	197,217	2,004,585	155,218	18,679,317	18,970,211	27,277,483	16,527,639
103		100%	0.17%	0.23%	2.39%	0.18%	22.25%	22.60%	32.49%	19.69%
		1.0000	**0.5760**	**0.1111**	**0.1070**	**0.0254**	**0.0504**	**0.0437**	**0.0632**	**0.0232**
104		100%	57.60%	11.11%	10.70%	2.54%	5.04%	4.37%	6.32%	2.32%
		1.0000	0.5662	0.1100	0.1060	0.0256	0.0505	0.0451	0.0705	0.0260
105		100%	56.62%	11.00%	10.60%	2.56%	5.05%	4.51%	7.05%	2.60%
		1.0000	0.6445	0.1192	0.1143	0.0250	0.0500	0.0343	0.0128	0.0000
106		100%	64.45%	11.92%	11.43%	2.50%	5.00%	3.43%	1.28%	0.00%
		1.0000	**0.6373**	**0.1221**	**0.1198**	**0.0301**	**0.0269**	**0.0223**	**0.0323**	**0.0094**
107		100%	63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		1,938,583	1,709,595	166,610	39,782	6,372	11,702	3,502	984	36
108		100%	88.19%	8.59%	2.05%	0.33%	0.60%	0.18%	0.05%	0.00%
		1,846,892	1,709,595	119,353	15,633	539	1,282	359	128	3
109		100%	92.57%	6.46%	0.85%	0.03%	0.07%	0.02%	0.01%	0.00%
		1.0000	0.9188	0.0641	0.0084	0.0003	0.0060	0.0018	0.0005	0.0000
110		100%	91.88%	6.41%	0.84%	0.03%	0.60%	0.18%	0.05%	0.00%
		534,788	340,760	68,465	66,764	16,621	11,224	10,299	14,969	5,686
111		100%	63.72%	12.80%	12.48%	3.11%	2.10%	1.93%	2.80%	1.06%
		350,109	210,527	43,912	43,496	9,996	11,224	10,299	14,969	5,686
112		100%	60.13%	12.54%	12.42%	2.86%	3.21%	2.94%	4.28%	1.62%
			0.8905	0.1023	0.0066	0.0006	(0.0002)	0.0001	0.0000	0.0000
113		100%	89.05%	10.23%	0.66%	0.06%	-0.02%	0.01%	0.00%	0.00%
			0.0000	0.7751	0.1960	0.0068	0.0156	0.0047	0.0017	0.0000
114		100%	0.00%	77.51%	19.60%	0.68%	1.56%	0.47%	0.17%	0.00%
			0.9655	0.0341	0.0004	0.0000	0.0001	0.0000	0.0000	0.0000
115		100%	96.55%	3.41%	0.04%	0.00%	0.01%	0.00%	0.00%	0.00%
		551,060	350,825	70,405	68,648	17,089	11,768	10,766	15,643	5,916
201		100%	63.66%	12.78%	12.46%	3.10%	2.14%	1.95%	2.84%	1.07%
		122,449	86,350	16,279	15,428	4,393	-	-	-	-
202		100%	70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
		3,323,679	2,024,051	388,962	378,482	92,831	125,443	106,963	154,646	52,302
204		100%	60.90%	11.70%	11.39%	2.79%	3.77%	3.22%	4.65%	1.57%
		8,678,876	6,739,874	851,502	495,664	104,814	206,010	140,813	111,260	28,938
205		100%	77.66%	9.81%	5.71%	1.21%	2.37%	1.62%	1.28%	0.33%
		3,446,129	2,110,401	405,241	393,910	97,223	125,443	106,963	154,646	52,302
206		100%	61.24%	11.76%	11.43%	2.82%	3.64%	3.10%	4.49%	1.52%
		70,152	42,777	8,219	7,996	1,964	2,626	2,239	3,237	1,095
207		100%	60.98%	11.72%	11.40%	2.80%	3.74%	3.19%	4.61%	1.56%
		3,167,656	1,935,894	371,921	361,677	89,050	116,789	99,602	144,005	48,719
208		100%	61.11%	11.74%	11.42%	2.81%	3.69%	3.14%	4.55%	1.54%
		36,635	22,310	4,287	4,172	1,023	1,383	1,179	1,705	576
209		100%	60.90%	11.70%	11.39%	2.79%	3.77%	3.22%	4.65%	1.57%
		36,635	22,310	4,287	4,172	1,023	1,383	1,179	1,705	576
214		100%	60.90%	11.70%	11.39%	2.79%	3.77%	3.22%	4.65%	1.57%
		176,858	104,532	23,554	23,703	5,117	4,878	4,888	7,146	3,040
215		100%	59.10%	13.32%	13.40%	2.89%	2.76%	2.76%	4.04%	1.72%
		89,207	54,367	10,447	10,164	2,495	3,350	2,857	4,130	1,397
216		100%	60.95%	11.71%	11.39%	2.80%	3.76%	3.20%	4.63%	1.57%
			0.6341	0.1180	0.1132	0.0251	0.0500	0.0357	0.0204	0.0034
217		100%	63.41%	11.80%	11.32%	2.51%	5.00%	3.57%	2.04%	0.34%

Schedule F-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
Projected 12 Month Period: November 2025-October 2026
($000)

Case No.: U-21806
Exhibit No.: A-16 (SMG-1)
Schedule: F-1
Page: 15 of 16
Witness: SMGeller
Date: December 2024

Allocation Factors- Distribution System

	Factor	Distribution System	4 Residential	5 Rate GS-1	6 Rate GS-2	7 Rate GS-3	8 Rate ST	9 Rate LT	10 Rate XLT	11 Rate XXLT
		307,735,810	157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
101			51.33%	9.73%	9.81%	2.66%	6.07%	6.16%	8.86%	5.37%
		223,782,881	157,808,704	29,751,571	28,194,984	8,027,623	0	0	0	0
102			70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
		83,952,929	141,259	197,217	2,004,585	155,218	18,679,317	18,970,211	27,277,483	16,527,639
103			0.17%	0.23%	2.39%	0.18%	22.25%	22.60%	32.49%	19.69%
		1.0000	0.5760	0.1111	0.1070	0.0254	0.0504	0.0437	0.0632	0.0232
104			57.60%	11.11%	10.70%	2.54%	5.04%	4.37%	6.32%	2.32%
		1.0000	0.5662	0.1100	0.1060	0.0256	0.0505	0.0451	0.0705	0.0260
105			56.62%	11.00%	10.60%	2.56%	5.05%	4.51%	7.05%	2.60%
		1.0000	0.6445	0.1192	0.1143	0.0250	0.0500	0.0343	0.0128	0.0000
106			64.45%	11.92%	11.43%	2.50%	5.00%	3.43%	1.28%	0.00%
		1.0000	0.6373	0.1221	0.1198	0.0301	0.0269	0.0223	0.0323	0.0094
107			63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		1,938,583	1,709,595	166,610	39,782	6,372	11,702	3,502	984	36
108			88.19%	8.59%	2.05%	0.33%	0.60%	0.18%	0.05%	0.00%
		1,846,892	1,709,595	119,353	15,633	539	1,282	359	128	3
109			92.57%	6.46%	0.85%	0.03%	0.07%	0.02%	0.01%	0.00%
		1.0000	0.9188	0.0641	0.0084	0.0003	0.0060	0.0018	0.0005	0.0000
110			91.88%	6.41%	0.84%	0.03%	0.60%	0.18%	0.05%	0.00%
		1,429,647	1,080,576	161,071	116,661	28,346	18,918	12,697	9,029	2,349
111			75.58%	11.27%	8.16%	1.98%	1.32%	0.89%	0.63%	0.16%
		$ 964,543	$ 752,591	$ 99,236	$ 58,061	$ 11,662	$ 18,918	$ 12,697	$ 9,029	$ 2,349
112			78.03%	10.29%	6.02%	1.21%	1.96%	1.32%	0.94%	0.24%
		1.00	0.8905	0.1023	0.0066	0.0006	(0.0002)	0.0001	-	-
113			89.05%	10.23%	0.66%	0.06%	-0.02%	0.01%	0.00%	0.00%
		1.00	-	0.7751	0.1960	0.0068	0.0156	0.0047	0.0017	0.0000
114			0.00%	77.51%	19.60%	0.68%	1.56%	0.47%	0.17%	0.00%
		1.00	0.9655	0.0341	0.0004	0.0000	0.0001	-	-	-
115			96.55%	3.41%	0.04%	0.00%	0.01%	0.00%	0.00%	0.00%
		1,438,552	1,087,382	162,059	117,410	28,541	18,992	12,744	9,066	2,359
201			75.59%	11.27%	8.16%	1.98%	1.32%	0.89%	0.63%	0.16%
		122,449	86,350	16,279	15,428	4,393	-	-	-	-
202			70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
		3,323,679	2,024,051	388,962	378,482	92,831	125,443	106,963	154,646	52,302
204			60.90%	11.70%	11.39%	2.79%	3.77%	3.22%	4.65%	1.57%
		8,678,876	6,739,874	851,502	495,664	104,814	206,010	140,813	111,260	28,938
205			77.66%	9.81%	5.71%	1.21%	2.37%	1.62%	1.28%	0.33%
		8,678,876	6,739,874	851,502	495,664	104,814	206,010	140,813	111,260	28,938
206			77.66%	9.81%	5.71%	1.21%	2.37%	1.62%	1.28%	0.33%
		83,734	65,027	8,215	4,782	1,011	1,988	1,359	1,073	279
207			77.66%	9.81%	5.71%	1.21%	2.37%	1.62%	1.28%	0.33%
		6,489,206	5,067,348	627,813	355,372	73,748	154,686	105,440	83,179	21,620
208			78.09%	9.67%	5.48%	1.14%	2.38%	1.62%	1.28%	0.33%
		177,984	144,108	16,061	8,154	1,663	3,482	2,289	1,772	456
209			80.97%	9.02%	4.58%	0.93%	1.96%	1.29%	1.00%	0.26%
		177,984 -	144,108	16,061	8,154	1,663	3,482	2,289	1,772	456
214			80.97%	9.02%	4.58%	0.93%	1.96%	1.29%	1.00%	0.26%
		359,242	274,415	41,161	26,114	4,924	5,959	3,942	2,159	568
215			76.39%	11.46%	7.27%	1.37%	1.66%	1.10%	0.60%	0.16%
		249,972	194,125	24,525	14,276	3,019	5,934	4,056	3,205	833
216			77.66%	9.81%	5.71%	1.21%	2.37%	1.62%	1.28%	0.33%
		1.0000	0.6341	0.1180	0.1132	0.0251	0.0500	0.0357	0.0204	0.0034
217			63.41%	11.80%	11.32%	2.51%	5.00%	3.57%	2.04%	0.34%

Schedule F-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
Projected 12 Month Period: November 2025-October 2026
($000)

Case No.: U-21806
Exhibit No.: A-16 (SMG-1)
Schedule: F-1
Page: 16 of 16
Witness: SMGeller
Date: December 2024

Allocation Factors- Storage System

	Factor	Storage System	4 Residential	5 Rate GS-1	6 Rate GS-2	7 Rate GS-3	8 Rate ST	9 Rate LT	10 Rate XLT	11 Rate XXLT
		307,735,810	157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
101		100%	51.33%	9.73%	9.81%	2.66%	6.07%	6.16%	8.86%	5.37%
		223,782,881	157,808,704	29,751,571	28,194,984	8,027,623	0	0	0	0
102		100%	70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
		83,952,929	141,259	197,217	2,004,585	155,218	18,679,317	18,970,211	27,277,483	16,527,639
103		100%	0.17%	0.23%	2.39%	0.18%	22.25%	22.60%	32.49%	19.69%
		1.0000	**0.5760**	**0.1111**	**0.1070**	**0.0254**	**0.0504**	**0.0437**	**0.0632**	**0.0232**
104		100%	57.60%	11.11%	10.70%	2.54%	5.04%	4.37%	6.32%	2.32%
		1.0000	0.5662	0.1100	0.1060	0.0256	0.0505	0.0451	0.0705	0.0260
105		100%	56.62%	11.00%	10.60%	2.56%	5.05%	4.51%	7.05%	2.60%
		1.0000	0.6445	0.1192	0.1143	0.0250	0.0500	0.0343	0.0128	0.0000
106		100%	64.45%	11.92%	11.43%	2.50%	5.00%	3.43%	1.28%	0.00%
		1.0000	**0.6373**	**0.1221**	**0.1198**	**0.0301**	**0.0269**	**0.0223**	**0.0323**	**0.0094**
107		100%	63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		1,938,583	1,709,595	166,610	39,782	6,372	11,702	3,502	984	36
108		100%	88.19%	8.59%	2.05%	0.33%	0.60%	0.18%	0.05%	0.00%
		1,846,892	1,709,595	119,353	15,633	539	1,282	359	128	3
109		100%	92.57%	6.46%	0.85%	0.03%	0.07%	0.02%	0.01%	0.00%
		1.0000	0.9188	0.0641	0.0084	0.0003	0.0060	0.0018	0.0005	0.0000
110		100%	91.88%	6.41%	0.84%	0.03%	0.60%	0.18%	0.05%	0.00%
		320,036	209,795	41,494	41,072	10,450	4,721	4,203	6,207	2,094
111		100%	65.55%	12.97%	12.83%	3.27%	1.48%	1.31%	1.94%	0.65%
	$	232,231	$ 147,876	$ 29,820	$ 30,009	$ 7,300	$ 4,721	$ 4,203	$ 6,207	$ 2,094
112		100%	63.68%	12.84%	12.92%	3.14%	2.03%	1.81%	2.67%	0.90%
		-	0.89	0.10	0.01	0.00	(0.00)	0.00	-	-
113		100%	89.05%	10.23%	0.66%	0.06%	-0.02%	0.01%	0.00%	0.00%
		-	-	0.78	0.20	0.01	0.02	0.00	0.00	0.00
114		100%	0.00%	77.51%	19.60%	0.68%	1.56%	0.47%	0.17%	0.00%
		-	0.97	0.03	0.00	0.00	0.00	-	-	-
115		100%	96.55%	3.41%	0.04%	0.00%	0.01%	0.00%	0.00%	0.00%
		323,525	212,075	41,933	41,501	10,561	4,789	4,259	6,289	2,119
201		100%	65.55%	12.96%	12.83%	3.26%	1.48%	1.32%	1.94%	0.65%
		122,449	86,350	16,279	15,428	4,393	-	-	-	-
202		100%	70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
		3,323,679	2,024,051	388,962	378,482	92,831	125,443	106,963	154,646	52,302
204		100%	60.90%	11.70%	11.39%	2.79%	3.77%	3.22%	4.65%	1.57%
		8,678,876	6,739,874	851,502	495,664	104,814	206,010	140,813	111,260	28,938
205		100%	77.66%	9.81%	5.71%	1.21%	2.37%	1.62%	1.28%	0.33%
		1,638,445	1,044,143	200,068	196,208	49,246	44,068	36,520	52,852	15,340
206		100%	63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		168,990	107,693	20,635	20,237	5,079	4,545	3,767	5,451	1,582
207		100%	63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		2,093,877	1,346,898	257,715	251,951	64,015	51,321	42,537	61,564	17,876
208		100%	64.33%	12.31%	12.03%	3.06%	2.45%	2.03%	2.94%	0.85%
		25,567	16,293	3,122	3,062	768	688	570	825	239
209		100%	63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		25,567	- 16,293	3,122	3,062	768	688	570	825	239
214		100%	63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		132,611	84,300	17,641	18,070	4,298	2,079	2,012	3,037	1,174
215		100%	63.57%	13.30%	13.63%	3.24%	1.57%	1.52%	2.29%	0.89%
		45,225	28,821	5,522	5,416	1,359	1,216	1,008	1,459	423
216		100%	63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		-	0.6341	0.1180	0.1132	0.0251	0.0500	0.0357	0.0204	0.0034
217		100%	63.41%	11.80%	11.32%	2.51%	5.00%	3.57%	2.04%	0.34%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
Projected 12 Month Period: November 2025-October 2026
($000)

Schedule F-1.1

Case No.: U-21806
Exhibit No.: A-16 (SMG-2)
Schedule: F-1.1
Page: 1 of 16
Witness: SMGeller
Date: December 2024

Line. No.	(a) Summary Description	(b) Classification	(c) Allocation	(d) Total	(e) Residential	(f) Rate GS-1	(g) Rate GS-2	(h) Rate GS-3	(i) Rate ST	(j) Rate LT	(k) Rate XLT	(l) Rate XXLT
1	Service Revenue			2,284,471	1,631,131	271,029	224,497	55,417	34,864	27,199	30,204	10,129
2	Other Revenue			28,666	19,152	3,367	3,061	774	685	570	793	265
3	Total Revenue			2,313,137	1,650,284	274,396	227,558	56,191	35,548	27,769	30,998	10,394
4	Expenses:											
5	Cost of Gas Sold (COGS)			737,588	520,137	98,061	92,931	26,459	-	-	-	-
6	O & M Expense			297,904	231,173	29,639	17,314	3,781	5,982	4,294	4,437	1,283
10	Depreciation & Amortization Expense			384,404	279,369	40,394	29,409	6,746	10,249	7,637	8,183	2,416
14	Lost and Unaccounted for (LAUF) Gas			12,709	8,962	1,690	1,601	456	-	-	-	-
18	Taxes			330,836	235,818	36,752	28,408	6,338	8,063	6,250	6,943	2,266
22	Company Use			5,502	3,880	731	693	197	-	-	-	-
26	Total Expenses			1,768,943	1,279,339	207,267	170,357	43,977	24,294	18,181	19,563	5,965
27	Net Operating Income			544,194	370,944	67,129	57,202	12,214	11,254	9,588	11,434	4,428
28	Test Year AFUDC	CWIP	207	1,298	869	149	132	32	36	29	38	12
32	Adjusted Net Operating Income			545,491	371,813	67,278	57,334	12,246	11,291	9,617	11,473	4,440
33	Total Rate Base			11,750,739	8,405,030	1,256,328	956,466	223,141	315,506	239,700	272,586	81,982
37	Return on Rate Base @ 6.22%			730,837.85	522,751	78,137	59,487	13,878	19,623	14,908	16,954	5,099
41	Income Deficiency/(Sufficiency)			185,346	150,938	10,859	2,154	1,632	8,332	5,291	5,481	659
42	Revenue Deficiency/(Sufficiency)			248,008	201,968	14,530	2,882	2,184	11,149	7,080	7,334	882
43	Rev Requirement/Total Cost of Service			$ 2,561,146	$ 1,852,251	$ 288,927	$ 230,440	$ 58,375	$ 46,698	$ 34,848	$ 38,331	$ 11,275
44	Less: Cost of Gas Sold (Test Yr)			737,588	520,137	98,061	92,931	26,459	-	-	-	-
45	Less: Miscellaneous Revenue (TY)			28,666	19,152	3,367	3,061	774	685	570	793	265
46	**Proposed Rate Design Revenue**			**1,794,891**	**1,312,961**	**187,499**	**134,448**	**31,142**	**46,013**	**34,279**	**37,538**	**11,011**
47	Customer			689,228	570,202	63,356	27,803	5,651	9,520	5,900	5,305	1,490
48	Demand			1,030,286	683,528	116,427	102,426	24,522	35,295	27,508	31,324	9,257
49	Energy			75,378	59,231	7,716	4,219	969	1,198	871	908	265

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	Proposed Rate Design Revenue Summary											
1	Transmission Related Cost			415,032	254,173	48,421	46,990	11,660	15,451	13,091	18,919	6,327
2	Customer			47,099	$ 28,685	$ 5,619	$ 5,488	$ 1,330	$ 1,679	$ 1,457	$ 2,109	$ 733
3	Demand			357,634	$ 219,069	$ 41,575	$ 40,314	$ 10,031	$ 13,439	$ 11,351	$ 16,400	$ 5,455
4	Energy			10,299	$ 6,419	$ 1,227	$ 1,188	$ 299	$ 332	$ 284	$ 410	$ 139
5	Storage Related Cost			256,882	164,859	31,383	30,617	7,782	6,631	5,462	7,891	2,257
6	Customer			27,060	$ 17,260	$ 3,358	$ 3,318	$ 826	$ 667	$ 563	$ 820	$ 248
7	Demand			223,042	$ 143,224	$ 27,191	$ 26,485	$ 6,748	$ 5,802	$ 4,764	$ 6,876	$ 1,952
8	Energy			6,780	$ 4,375	$ 834	$ 814	$ 208	$ 163	$ 135	$ 195	$ 56
9	Distribution Related Cost			1,122,977	893,929	107,695	56,842	11,700	23,931	15,725	10,729	2,426
10	Customer			615,069	$ 524,257	$ 54,379	$ 18,998	$ 3,496	$ 7,174	$ 3,880	$ 2,377	$ 509
11	Demand			449,609	$ 321,235	$ 47,661	$ 35,626	$ 7,743	$ 16,054	$ 11,393	$ 8,049	$ 1,849
12	Energy			58,299	$ 48,437	$ 5,654	$ 2,217	$ 462	$ 703	$ 453	$ 303	$ 70
13	Total			1,794,891	1,312,961	187,499	134,448	31,142	46,013	34,279	37,538	11,011
14	Customer			689,228	570,202	63,356	27,803	5,651	9,520	5,900	5,305	1,490
15	Demand			1,030,286	683,528	116,427	102,426	24,522	35,295	27,508	31,324	9,257
16	Energy			75,378	59,231	7,716	4,219	969	1,198	871	908	265
17	Mcf Thruput			307,735,810	157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
18	Customer Count			1,846,892	1,709,595	119,353	15,633	539	1,282	359	128	3

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1	Production Plant	DEMAND	102	122,449	86,350	16,279	15,428	4,393	-	-	-	-
5	Storage Plant	DEMAND	107	1,638,445	1,044,143	200,068	196,208	49,246	44,068	36,520	52,852	15,340
9	Transmission To/From Storage	DEMAND	107	1,789,747	1,140,564	218,543	214,326	53,794	48,137	39,892	57,733	16,757
13	Other Transmission	DEMAND	104	1,533,933	883,487	170,419	164,156	39,037	77,306	67,070	96,913	35,545
17	Total Transmission Plant			3,323,679	2,024,051	388,962	378,482	92,831	125,443	106,963	154,646	52,302
21	Distribution Plant - Other	DEMAND	105	-	-	-	-	-	-	-	-	-
25	Distribution Plant - Other - Fee Land & Easements (374)	DEMAND	104	33,181	19,111	3,686	3,551	844	1,672	1,451	2,096	769
29	Distribution Plant - Other - Structures and Improvements (375)	DEMAND	104	69,188	39,849	7,687	7,404	1,761	3,487	3,025	4,371	1,603
33	Distribution Plant - Other - Compressor Station Equipment (377)	DEMAND	104	11,885	6,845	1,320	1,272	302	599	520	751	275
37	Distribution Plant - Other - M & R General (378)	DEMAND	104	355,404	204,699	39,485	38,034	9,045	17,911	15,540	22,454	8,236
41	Distribution Plant - Other - Meter Installations (382)	CUST	108	34,919	30,794	3,001	717	115	211	63	18	1
45	Mains - High Pressure Capable	DEMAND	105	372,982	211,177	41,031	39,554	9,540	18,846	16,840	26,297	9,697
49	Mains - Non-High Pressure Capable	DEMAND	106	2,447,265	1,577,191	291,660	279,751	61,190	122,243	83,849	31,370	11
53	Services & Meters	CUST	108	5,354,052	4,721,624	460,150	109,871	17,598	32,319	9,672	2,718	99
57	Total Distribution Plant			8,678,876	6,811,291	848,020	480,154	100,395	197,288	130,960	90,076	20,692
61	Total Plant In Service excl Gen, Com, & Int			13,763,449	9,965,835	1,453,329	1,070,271	246,865	366,799	274,442	297,574	88,334
65	Gen, Com, & Int Plant and PHFFU	PLANT	206	820,939	594,425	86,686	63,838	14,725	21,878	16,369	17,749	5,269
69	Total Test Year Plant in Service			14,584,387	10,560,260	1,540,015	1,134,109	261,589	388,678	290,812	315,323	93,603

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1	Production CWIP	PROD_PLANT	202	-	-	-	-	-	-	-	-	-
5	Storage CWIP	STOR_PLANT	107	161,299	102,792	19,696	19,316	4,848	4,338	3,595	5,203	1,510
9	Transmission CWIP	TRAN_PLANT	204	53,976	32,870	6,317	6,146	1,508	2,037	1,737	2,511	849
13	Distribution CWIP	DIST_PLANT	205	42,995	33,743	4,201	2,379	497	977	649	446	103
17	General, Common & Intangible and PHFFU CWIP	PLANT	206	64,606	46,780	6,822	5,024	1,159	1,722	1,288	1,397	415
21	Total CWIP			322,877	216,186	37,036	32,865	8,012	9,075	7,269	9,558	2,877
25	Production Accumulated Depreciation	PROD_PLANT	202	(8,245)	(5,814)	(1,096)	(1,039)	(296)	-	-	-	-
29	Storage Accumulated Depreciation	STOR_PLANT	107	(253,855)	(161,776)	(30,998)	(30,400)	(7,630)	(6,828)	(5,658)	(8,189)	(2,377)
33	Transmission Accumulated Depreciation	TRAN_PLANT	204	(615,340)	(374,729)	(72,012)	(70,072)	(17,187)	(23,224)	(19,803)	(28,631)	(9,683)
37	Distribution Accumulated Depreciation	DIST_PLANT	205	(3,209,490)	(2,518,848)	(313,602)	(177,563)	(37,127)	(72,958)	(48,430)	(33,310)	(7,652)
41	General, Common & Intangible and PHFFU Accumulated Depreciation	PLANT	206	(578,782)	(419,084)	(61,116)	(45,007)	(10,381)	(15,425)	(11,541)	(12,514)	(3,715)
45	Total Accumulated Depreciation			(4,665,713)	(3,480,252)	(478,823)	(324,080)	(72,620)	(118,435)	(85,432)	(82,644)	(23,426)
49	Cash & Cash Equivalents	ENERGY	209	696,014	534,226	69,205	42,990	9,462	14,972	10,764	11,162	3,233
53	Accounts Receivable	ENERGY	111	109,689	78,319	13,014	10,779	2,661	1,674	1,306	1,450	486
57	Materials and Supplies	O&M (EXC. A&G)	209	55,983	42,969	5,566	3,458	761	1,204	866	898	260

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1	Gas Stored Underground- Recoverable Base Gas	STOR_PLANT	107	173,941	110,849	21,240	20,830	5,228	4,678	3,877	5,611	1,629
5	Gas Stored Underground- Working Gas	STOR_PLANT	102	208,094	146,745	27,666	26,218	7,465	-	-	-	-
9	Real & Personal Property Taxes	PLANT	206	176,164	127,557	18,602	13,699	3,160	4,695	3,513	3,809	1,131
13	Other Assets	PLANT	206	-	-	-	-	-	-	-	-	-
17	Deferred Debits	PLANT	206	466,865	338,047	49,298	36,304	8,374	12,442	9,309	10,094	2,996
21	Total Assets			1,886,750	1,378,712	204,590	154,279	37,111	39,665	29,634	33,024	9,735
25	Accounts Payable	ENERGY	102	234,904	165,651	31,230	29,596	8,427	-	-	-	-
29	Dividends Declared	PLANT	215	14,780	10,119	1,812	1,533	327	306	259	306	118
33	Customer Deposits	ENERGY	111	11,793	8,913	1,329	962	234	156	105	74	19
37	Accrued Interest	PLANT	206	42,561	30,817	4,494	3,310	763	1,134	849	920	273
41	Accrued Taxes - Federal	PLANT	215	771	528	95	80	17	16	13	16	6
45	Accrued Taxes - State	PLANT	215	(98)	(67)	(12)	(10)	(2)	(2)	(2)	(2)	(1)
49	Accrued Taxes - R&PP Tax & Other	PLANT	206	11,726	8,490	1,238	912	210	312	234	254	75
53	Other Liabilities	PLANT	206	30,215	21,878	3,191	2,350	542	805	602	653	194

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1	Deferred Credits	PLANT	206	31,718	22,967	3,349	2,466	569	845	632	686	204
5	Total Liabilities			378,369	269,297	46,726	41,198	11,087	3,573	2,693	2,907	889
9	Total Working Capital			1,508,380	1,109,415	157,864	113,080	26,024	36,092	26,942	30,117	8,846
13	Test Year Unamortized MGP Expense - Net	PLANT	206	19,967	14,458	2,108	1,553	358	532	398	432	128
17	Test Year Retainers & Customer Advances-Net	DIST_PLANT	205	(19,159)	(15,037)	(1,872)	(1,060)	(222)	(436)	(289)	(199)	(46)
21	Adjustments to Rate Base			808	(579)	236	493	137	97	109	233	82
25	Total Test Year Rate Base			11,750,739	8,405,030	1,256,328	956,466	223,141	315,506	239,700	272,586	81,982
29	Production O&M	PROD_PLANT	202	-	-	-	-	-	-	-	-	-
33	Storage O&M	STOR_PLANT	107	23,968	15,274	2,927	2,870	720	645	534	773	224
37	Transmission O&M	TRAN_PLANT	204	34,344	20,915	4,019	3,911	959	1,296	1,105	1,598	540
41	Distribution O&M	DIST_PLANT	205	128,141	100,567	12,521	7,089	1,482	2,913	1,934	1,330	306
45	Customer Accounting O&M	CUST	110	36,633	33,658	2,350	308	11	221	66	19	1
49	Customer Service & Information O&M	CUST	109	394	365	25	3	0	0	0	0	0
53	Customer Assistance O&M	CUST	109	1,687	1,561	109	14	0	1	0	0	0

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1	Total Test Year O&M Expense			225,167	172,340	21,951	14,196	3,173	5,076	3,640	3,720	1,071
5	Administrative & General Expense	O&M (EXC. A&G)	209	82,571	63,378	8,210	5,100	1,123	1,776	1,277	1,324	384
9	Business Customer Care	CUST	114	1,776	-	1,377	348	12	28	8	3	0
13	Customer Contact Center	CUST	115	13,243	12,786	451	5	0	1	-	-	-
17	Interest on Customer Deposits	ENERGY	111	237	179	27	19	5	3	2	1	0
21	Test Year Uncollectible Expense	ENERGY	113	15,327	13,649	1,569	101	9	(3)	2	-	-
25		ENERGY	209	-	-	-	-	-	-	-	-	-
29	Production- Pension & Benefits Expense	PROD_PLANT	202	-	-	-	-	-	-	-	-	-
33	Storage- Pension & Benefits Expense	STOR_PLANT	107	(2,414)	(1,538)	(295)	(289)	(73)	(65)	(54)	(78)	(23)
37	Transmission- Pension & Benefits Expense	TRAN_PLANT	204	(3,766)	(2,294)	(441)	(429)	(105)	(142)	(121)	(175)	(59)
41	Distribution- Pension & Benefits Expense	DIST_PLANT	205	(21,341)	(16,749)	(2,085)	(1,181)	(247)	(485)	(322)	(221)	(51)
45	Customer Accounting (Billing)- Pension & Benefits Expense	CUST	110	(4,264)	(3,918)	(274)	(36)	(1)	(26)	(8)	(2)	(0)
49	Customer Service- Pension & Benefits Expense	CUST	109	(221)	(205)	(14)	(2)	(0)	(0)	(0)	(0)	(0)
53	Sales Expense- Pension & Benefits Expense	O&M (EXC. A&G)	209	(10)	(8)	(1)	(0)	(0)	(0)	(0)	(0)	(0)
57	Administrative & General- Pension & Benefits Expense	CUST	209	(8,400)	(6,447)	(835)	(519)	(114)	(181)	(130)	(135)	(39)
61	Total Test Year Pension & Benefits Expense			(40,418)	(31,160)	(3,945)	(2,456)	(540)	(899)	(635)	(612)	(172)
65	Production- Payroll Tax	PROD_PLANT	202	-	-	-	-	-	-	-	-	-

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1	Storage- Payroll Tax	STOR_PLANT	107	876	558	107	105	26	24	20	28	8
5	Transmission- Payroll Tax	TRAN_PLANT	204	1,367	832	160	156	38	52	44	64	22
9	Distribution- Payroll Tax	DIST_PLANT	205	7,744	6,078	757	428	90	176	117	80	18
13	Customer Accounting (Billing)- Payroll Tax	CUST	110	1,547	1,422	99	13	0	9	3	1	0
17	Customer Service- Payroll Tax	CUST	109	80	74	5	1	0	0	0	0	0
21	Sales Expense- Payroll Tax	O&M (EXC. A&G)	209	4	3	0	0	0	0	0	0	0
25	Administrative & General- Payroll Tax	CUST	209	3,048	2,340	303	188	41	66	47	49	14
29	Total Payroll Tax			14,666	11,307	1,431	891	196	326	230	222	62
33	Production- Depreciation & Amortization Exp	PROD_PLANT	202	-	-	-	-	-	-	-	-	-
37	Storage- Depreciation & Amortization Exp	STOR_PLANT	107	39,352	25,078	4,805	4,713	1,183	1,058	877	1,269	368
41	Transmission- Depreciation & Amortization Exp	TRAN_PLANT	204	76,856	46,804	8,994	8,752	2,147	2,901	2,473	3,576	1,209
45	Distribution- Depreciation & Amortization Exp	DIST_PLANT	205	218,868	171,770	21,386	12,109	2,532	4,975	3,303	2,272	522
49	Gen, Com, & Int- Depreciation & Amortization Exp	PLANT	206	49,327	35,717	5,209	3,836	885	1,315	984	1,066	317
53	Test Year Total Depreciation & Amortization Exp			384,404	279,369	40,394	29,409	6,746	10,249	7,637	8,183	2,416

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1	Test Year Lost and Unaccounted for (LAUF) Gas	ENERGY	102	12,709	8,962	1,690	1,601	456	-	-	-	-
5	Test Year Company Use	ENERGY	102	5,502	3,880	731	693	197	-	-	-	-
9	Test Year Property Taxes	PLANT	206	201,200	145,685	21,245	15,646	3,609	5,362	4,012	4,350	1,291
13	Test Year Federal, State & City Income Tax	PLANT	215	111,893	76,610	13,721	11,603	2,476	2,314	1,959	2,318	893
17	TCJA Amortization	PLANT	208	(2,042)	(1,461)	(218)	(166)	(39)	(55)	(42)	(47)	(14)
21		PLANT	208	-	-	-	-	-	-	-	-	-
25	Test Year Miscellaneous Taxes	ENERGY	112	5,119	3,677	572	434	95	116	90	100	34
29	Total Test Year Other Taxes			316,170	224,511	35,320	27,517	6,142	7,737	6,019	6,721	2,203
33	Total Test Year Expenses Excluding COGS & Company Use			1,025,616	755,143	108,448	76,713	17,316	24,291	18,179	19,562	5,965
37	Test Year Cost of Gas Sold (COGS)			737,588	520,137	98,061	92,931	26,459	-	-	-	-

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1	Test Year Service Revenue Including Cost of Gas Sold			2,284,471	1,631,131	271,029	224,497	55,417	34,864	27,199	30,204	10,129
	Other Revenues											
2	Forfeited Discounts (Late Payment Charge)		111	6,322	4,514	750	621	153	96	75	84	28
3	Misc Service Rev (ASP)		102	1,356	956	180	171	49	-	-	-	-
4	Rev from Transmission of Gas of Others		204	13,448	8,189	1,574	1,531	376	508	433	626	212
5	Rent from Gas Property		204	290	176	34	33	8	11	9	13	5
6	Joint Commodities Mrkt Agrmt Rev		102	-	-	-	-	-	-	-	-	-
7	GCR related charges to Transport Customers		102	3,421	2,413	455	431	123	-	-	-	-
8	Gas Merchant-Buy/sell Contracts		107	-	-	-	-	-	-	-	-	-
9	Rev from Storage Agrmts (GM, MCV & others)		107	1,905	1,214	233	228	57	51	42	61	18
10	Administrative Customer Acctg charges for GCC		110	1,487	1,366	95	12	0	9	3	1	0
11	Interest on Cash Operating Accounts		209	358	266	37	25	6	8	6	7	2
12	Miscellaneous		111	81	58	10	8	2	1	1	1	0
13	Total Other Test Year Revenues			28,666	19,152	3,367	3,061	774	685	570	793	265
14	Total Test Year Revenues			2,313,137	1,650,284	274,396	227,558	56,191	35,548	27,769	30,998	10,394

Schedule F-1.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
Projected 12 Month Period: November 2025-October 2026
($000)

Case No.: U-21806
Exhibit No.: A-16 (SMG-2)
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Functionalization Factors

	1	2	3	4	5
Description	**Source**	**Factor**	**Total System**	**Distribution**	**Transmission**	**Storage**
CWIP			322,877	83,734	70,152	168,990
	INTERNAL- Input Line 52	CWIP		25.9%	21.7%	52.3%
Distribution			1	1	0	0
	N/A	DIST		100.0%	0.0%	0.0%
O&M Expense			225,167	$ 166,855	$ 34,344	$ 23,968
	INTERNAL- Input Line 90	O&M		74.1%	15.3%	10.6%
O&M/Plant in Service		-	-	-	-	
	INTERNAL- 50/50 Weighting of O&M & PIS	O&M/PIS		68.6%	20.1%	11.3%
Plant in Service			13,763,449	$ 8,678,876	$ 3,446,129	$ 1,638,445
	INTERNAL- Input Line 44	PIS		63.1%	25.0%	11.9%
Rate Base			11,750,739	$ 6,489,133	$ 3,167,696	$ 2,093,910
	INTERNAL- Input Line 82	RB		55.2%	27.0%	17.8%
Total Revenue			2,284,471	1,429,647	534,788	320,036
	INTERNAL- Input Line 34	REV		62.6%	23.4%	14.0%
Storage			1	-	-	1
	N/A	STOR		0.0%	0.0%	100.0%
Taxable Income			654,045	358,737	177,317	133,009
	INTERNAL- Input- Summary & Expense	TAXABLEINC		53.6%	26.5%	19.9%
Transmission			1	-	1	-
	N/A	TRAN		0.0%	100.0%	0.0%

Schedule F-1.1

Michigan Service Public Commission
Consumers Energy Company
Gas Cost-of-Service Study
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Classification Factors		1	2	3	4	5
Description	Source	Factor	Total System	Customer	Demand	Energy
Demand	N/A		1	0	1	0
		DEMAND		0%	100%	0%
Customer	N/A		1	1	0	0
		CUST		100%	0%	0%
Energy/Commodity	N/A		1	0	0	1
		ENERGY		0%	0%	100%
Total Plant (exc. General, Common & Intangible Plant)			13,763,449	5,388,971	8,374,478	-
	INTERNAL-Total COSS, Page 3 of 16, Line 61	PLANT		39%	61%	0%
Transmission Plant			3,323,679	-	3,323,679	-
	INTERNAL- Total COSS, Page 3 of 16, Line 17	TRAN_PLANT		0%	100%	0%
Distribution Plant			8,678,876	5,388,971	3,289,905	-
	INTERNAL- Total COSS, Page 3 of 16, Line 57	DIST_PLANT		62.09%	37.91%	0%
Production Plant			122,449	-	122,449	-
	INTERNAL- Total COSS, Page 3 of 16, Line 1	PROD_PLANT		0%	100%	0%
Storage Plant			1,638,445	-	1,638,445	-
	INTERNAL- Total COSS, Page 3 of 16, Line 5	STOR_PLANT		0%	100%	0%
Distribution Mains	N/A		-	-	-	-
		DIST_MAIN		0%	0%	0%
O&M Expense			225,167	118,281	106,887	-
	INTERNAL- Total COSS, Page 7 of 16, Line 1	O&M (EXC. A&G)		53%	47%	0%
CWIP			322,877	51,993	270,884	-
	INTERNAL- Total COSS, Page 4 of 16, Line 21	CWIP		16%	84%	0%

Schedule F-1.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
Projected 12 Month Period: November 2025-October 2026
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Allocation Factors- Total System

	1	2	3	4	5	6	7	8	9	10	11
Description	**Factor**	**Total System**		**Residential**	**Rate GS-1**	**Rate GS-2**	**Rate GS-3**	**Rate ST**	**Rate LT**	**Rate XLT**	**Rate XXLT**
Total Annual Throughput		307,735,810		157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
WP-SMG-9	101			51.33%	9.73%	9.81%	2.66%	6.07%	6.16%	8.86%	5.37%
GCR Throughput		223,782,881		157,808,704	29,751,571	28,194,984	8,027,623	0	0	0	0
WP-SMG-9	102			70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
Transportation Throughput		83,952,929		141,259	197,217	2,004,585	155,218	18,679,317	18,970,211	27,277,483	16,527,639
WP-SMG-9	103			0.17%	0.23%	2.39%	0.18%	22.25%	22.60%	32.49%	19.69%
Average & Peak (Transmission)		1.0000		0.5760	0.1111	0.1070	0.0254	0.0504	0.0437	0.0632	0.0232
WP-SMG-9	104			57.60%	11.11%	10.70%	2.54%	5.04%	4.37%	6.32%	2.32%
Average & Peak (High Pressure)		1.0000		0.5662	0.1100	0.1060	0.0256	0.0505	0.0451	0.0705	0.0260
WP-SMG-10	105			56.62%	11.00%	10.60%	2.56%	5.05%	4.51%	7.05%	2.60%
Average & Peak (Non-High Pressure)		1.0000		0.6445	0.1192	0.1143	0.0250	0.0500	0.0343	0.0128	0.0000
WP-SMG-10	106			64.45%	11.92%	11.43%	2.50%	5.00%	3.43%	1.28%	0.00%
Average & Peak (50% Storage 50% Peak Month)		1.0000		0.6373	0.1221	0.1198	0.0301	0.0269	0.0223	0.0323	0.0094
WP-SMG-11	107			63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
Weighted Customer		1,938,583		1,709,595	166,610	39,782	6,372	11,702	3,502	984	36
WP-SMG-16	108			88.19%	8.59%	2.05%	0.33%	0.60%	0.18%	0.05%	0.00%
Average Number of Customers		1,846,892		1,709,595	119,353	15,633	539	1,282	359	128	3
WP-SMG-16	109			92.57%	6.46%	0.85%	0.03%	0.07%	0.02%	0.01%	0.00%
Weighted/Average Customer		1.0000		0.9188	0.0641	0.0084	0.0003	0.0060	0.0018	0.0005	0.0000
WP-SMG-16	110			91.88%	6.41%	0.84%	0.03%	0.60%	0.18%	0.05%	0.00%
Present Total Revenue (Including COGS)		2,284,471		1,631,131	271,029	224,497	55,417	34,864	27,199	30,204	10,129
Exhibit A-16 (SAS-1), Sch F-2	111	100%		71.40%	11.86%	9.83%	2.43%	1.53%	1.19%	1.32%	0.44%
Present Delivery Revenue (Excluding COGS)		1,546,883		1,110,994	172,968	131,566	28,958	34,864	27,199	30,204	10,129
Exhibit A-16 (SAS-1), Sch F-2	112	100%		71.82%	11.18%	8.51%	1.87%	2.25%	1.76%	1.95%	0.65%
Net Write Off		1.00		0.8905	0.1023	0.0066	0.0006	(0.0002)	0.0001	0.0000	0.0000
WP-SMG-22	113			89.05%	10.23%	0.66%	0.06%	-0.02%	0.01%	0.00%	0.00%
BCC		1.00		0.0000	0.7751	0.1960	0.0068	0.0156	0.0047	0.0017	0.0000
WP-SMG-25	114			0.00%	77.51%	19.60%	0.68%	1.56%	0.47%	0.17%	0.00%
CCC		1.00		0.9655	0.0341	0.0004	0.0000	0.0001	0.0000	0.0000	0.0000
WP-SMG-25	115			96.55%	3.41%	0.04%	0.00%	0.01%	0.00%	0.00%	0.00%
Total Revenue		2,313,137		1,650,284	274,396	227,558	56,191	35,548	27,769	30,998	10,394
INTERNAL- COSS PAGE 1, Line 3	201			71.34%	11.86%	9.84%	2.43%	1.54%	1.20%	1.34%	0.45%
Total Production Plant		122,449		86,350	16,279	15,428	4,393	-	-	-	-
INTERNAL- Total COSS, Page 3 of 16, Line 1	202			70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
Total Transmission Plant		3,323,679		2,024,051	388,962	378,482	92,831	125,443	106,963	154,646	52,302
INTERNAL- Total COSS, Page 3 of 16, Line 17	204			60.90%	11.70%	11.39%	2.79%	3.77%	3.22%	4.65%	1.57%
Total Distribution Plant		8,678,876		6,811,291	848,020	480,154	100,395	197,288	130,960	90,076	20,692
INTERNAL- Total COSS, Page 3 of 16, Line 57	205			78.48%	9.77%	5.53%	1.16%	2.27%	1.51%	1.04%	0.24%
Total Plant in Service (excluding Gen, Com & Int)		13,763,449		9,965,835	1,453,329	1,070,271	246,865	366,799	274,442	297,574	88,334
INTERNAL- COSS PAGE 3, Line 61	206			72.41%	10.56%	7.78%	1.79%	2.67%	1.99%	2.16%	0.64%
Total CWIP		322,877		216,186	37,036	32,865	8,012	9,075	7,269	9,558	2,877
INTERNAL- COSS PAGE 4, Line 21	207			66.96%	11.47%	10.18%	2.48%	2.81%	2.25%	2.96%	0.89%
Rate Base		11,750,739		8,405,030	1,256,328	956,466	223,141	315,506	239,700	272,586	81,982
INTERNAL- COSS PAGE 6, Line 25	208			71.53%	10.69%	8.14%	1.90%	2.68%	2.04%	2.32%	0.70%
Total O&M (excluding Admin & General)		240,186		185,126	23,779	14,549	3,185	5,105	3,648	3,723	1,071
INTERNAL- COSS PAGE 7, Line 1,9,13	209			77.08%	9.90%	6.06%	1.33%	2.13%	1.52%	1.55%	0.45%
Total O&M Expense		240,186		185,126	23,779	14,549	3,185	5,105	3,648	3,723	1,071
INTERNAL- COSS PAGE 7, Line 1,9,13	214			77.08%	9.90%	6.06%	1.33%	2.13%	1.52%	1.55%	0.45%
Pretax Net Operating Income		668,711		457,401	82,064	69,530	14,847	13,839	11,735	13,927	5,369
INTERNAL- COSS (Multiple Pages & Lines)	215			68.40%	12.27%	10.40%	2.22%	2.07%	1.75%	2.08%	0.80%
Total Depreciation & Amortization		384,404		279,369	40,394	29,409	6,746	10,249	7,637	8,183	2,416
INTERNAL- COSS PAGE 8, Line 53	216			72.68%	10.51%	7.65%	1.75%	2.67%	1.99%	2.13%	0.63%
Weighted HP and Non HP Plant		1.00		0.6341	0.1180	0.1132	0.0251	0.0500	0.0357	0.0204	0.0034
WP-SMG-24	217			63.41%	11.80%	11.32%	2.51%	5.00%	3.57%	2.04%	0.34%

Schedule F-1.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
Projected 12 Month Period: November 2025-October 2026
($000)

Case No.: U-21806
Exhibit No.: A-16 (SMG-2)
Schedule: F-1.1
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Witness: SMGeller
Date: December 2024

Allocation Factors- Transmission System

		4	5	6	7	8	9	10	11
	Transmission								
Factor	System	Residential	Rate GS-1	Rate GS-2	Rate GS-3	Rate ST	Rate LT	Rate XLT	Rate XXLT
	307,735,810	157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
101	100%	51.33%	9.73%	9.81%	2.66%	6.07%	6.16%	8.86%	5.37%
	223,782,881	157,808,704	29,751,571	28,194,984	8,027,623	0	0	0	0
102	100%	70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
	83,952,929	141,259	197,217	2,004,585	155,218	18,679,317	18,970,211	27,277,483	16,527,639
103	100%	0.17%	0.23%	2.39%	0.18%	22.25%	22.60%	32.49%	19.69%
	1.0000	**0.5760**	**0.1111**	**0.1070**	**0.0254**	**0.0504**	**0.0437**	**0.0632**	**0.0232**
104	100%	57.60%	11.11%	10.70%	2.54%	5.04%	4.37%	6.32%	2.32%
	1.0000	0.5662	0.1100	0.1060	0.0256	0.0505	0.0451	0.0705	0.0260
105	100%	56.62%	11.00%	10.60%	2.56%	5.05%	4.51%	7.05%	2.60%
	1.0000	0.6445	0.1192	0.1143	0.0250	0.0500	0.0343	0.0128	0.0000
106	100%	64.45%	11.92%	11.43%	2.50%	5.00%	3.43%	1.28%	0.00%
	1.0000	**0.6373**	**0.1221**	**0.1198**	**0.0301**	**0.0269**	**0.0223**	**0.0323**	**0.0094**
107	100%	63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
	1,938,583	1,709,595	166,610	39,782	6,372	11,702	3,502	984	36
108	100%	88.19%	8.59%	2.05%	0.33%	0.60%	0.18%	0.05%	0.00%
	1,846,892	1,709,595	119,353	15,633	539	1,282	359	128	3
109	100%	92.57%	6.46%	0.85%	0.03%	0.07%	0.02%	0.01%	0.00%
	1.0000	0.9188	0.0641	0.0084	0.0003	0.0060	0.0018	0.0005	0.0000
110	100%	91.88%	6.41%	0.84%	0.03%	0.60%	0.18%	0.05%	0.00%
	534,788	340,760	68,465	66,764	16,621	11,224	10,299	14,969	5,686
111	100%	63.72%	12.80%	12.48%	3.11%	2.10%	1.93%	2.80%	1.06%
	350,109	210,527	43,912	43,496	9,996	11,224	10,299	14,969	5,686
112	100%	60.13%	12.54%	12.42%	2.86%	3.21%	2.94%	4.28%	1.62%
		0.8905	0.1023	0.0066	0.0006	(0.0002)	0.0001	0.0000	0.0000
113	100%	89.05%	10.23%	0.66%	0.06%	-0.02%	0.01%	0.00%	0.00%
		0.0000	0.7751	0.1960	0.0068	0.0156	0.0047	0.0017	0.0000
114	100%	0.00%	77.51%	19.60%	0.68%	1.56%	0.47%	0.17%	0.00%
		0.9655	0.0341	0.0004	0.0000	0.0001	0.0000	0.0000	0.0000
115	100%	96.55%	3.41%	0.04%	0.00%	0.01%	0.00%	0.00%	0.00%
	551,060	350,825	70,405	68,648	17,089	11,768	10,766	15,643	5,916
201	100%	63.66%	12.78%	12.46%	3.10%	2.14%	1.95%	2.84%	1.07%
	122,449	86,350	16,279	15,428	4,393	-	-	-	-
202	100%	70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
	3,323,679	2,024,051	388,962	378,482	92,831	125,443	106,963	154,646	52,302
204	100%	60.90%	11.70%	11.39%	2.79%	3.77%	3.22%	4.65%	1.57%
	8,678,876	6,811,291	848,020	480,154	100,395	197,288	130,960	90,076	20,692
205	100%	78.48%	9.77%	5.53%	1.16%	2.27%	1.51%	1.04%	0.24%
	3,446,129	2,110,401	405,241	393,910	97,223	125,443	106,963	154,646	52,302
206	100%	61.24%	11.76%	11.43%	2.82%	3.64%	3.10%	4.49%	1.52%
	70,152	42,777	8,219	7,996	1,964	2,626	2,239	3,237	1,095
207	100%	60.98%	11.72%	11.40%	2.80%	3.74%	3.19%	4.61%	1.56%
	3,167,696	1,935,917	371,927	361,683	89,051	116,790	99,602	144,007	48,720
208	100%	61.11%	11.74%	11.42%	2.81%	3.69%	3.14%	4.55%	1.54%
	34,344	20,915	4,019	3,911	959	1,296	1,105	1,598	540
209	100%	60.90%	11.70%	11.39%	2.79%	3.77%	3.22%	4.65%	1.57%
	34,344	20,915	4,019	3,911	959	1,296	1,105	1,598	540
214	100%	60.90%	11.70%	11.39%	2.79%	3.77%	3.22%	4.65%	1.57%
	179,149	105,927	23,822	23,964	5,181	4,965	4,962	7,252	3,076
215	100%	59.13%	13.30%	13.38%	2.89%	2.77%	2.77%	4.05%	1.72%
	89,207	54,367	10,447	10,164	2,495	3,350	2,857	4,130	1,397
216	100%	60.95%	11.71%	11.39%	2.80%	3.76%	3.20%	4.63%	1.57%
		0.6341	0.1180	0.1132	0.0251	0.0500	0.0357	0.0204	0.0034
217	100%	63.41%	11.80%	11.32%	2.51%	5.00%	3.57%	2.04%	0.34%

Schedule F-1.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
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($000)

Case No.: U-21806
Exhibit No.: A-16 (SMG-2)
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Witness: SMGeller
Date: December 2024

Allocation Factors- Distribution System

	Factor	Distribution System		4 Residential	5 Rate GS-1	6 Rate GS-2	7 Rate GS-3	8 Rate ST	9 Rate LT	10 Rate XLT	11 Rate XXLT
		307,735,810		157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
101				51.33%	9.73%	9.81%	2.66%	6.07%	6.16%	8.86%	5.37%
		223,782,881		157,808,704	29,751,571	28,194,984	8,027,623	0	0	0	0
102				70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
		83,952,929		141,259	197,217	2,004,585	155,218	18,679,317	18,970,211	27,277,483	16,527,639
103				0.17%	0.23%	2.39%	0.18%	22.25%	22.60%	32.49%	19.69%
		1.0000		0.5760	0.1111	0.1070	0.0254	0.0504	0.0437	0.0632	0.0232
104				57.60%	11.11%	10.70%	2.54%	5.04%	4.37%	6.32%	2.32%
		1.0000		0.5662	0.1100	0.1060	0.0256	0.0505	0.0451	0.0705	0.0260
105				56.62%	11.00%	10.60%	2.56%	5.05%	4.51%	7.05%	2.60%
		1.0000		0.6445	0.1192	0.1143	0.0250	0.0500	0.0343	0.0128	0.0000
106				64.45%	11.92%	11.43%	2.50%	5.00%	3.43%	1.28%	0.00%
		1.0000		0.6373	0.1221	0.1198	0.0301	0.0269	0.0223	0.0323	0.0094
107				63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		1,938,583		1,709,595	166,610	39,782	6,372	11,702	3,502	984	36
108				88.19%	8.59%	2.05%	0.33%	0.60%	0.18%	0.05%	0.00%
		1,846,892		1,709,595	119,353	15,633	539	1,282	359	128	3
109				92.57%	6.46%	0.85%	0.03%	0.07%	0.02%	0.01%	0.00%
		1.0000		0.9188	0.0641	0.0084	0.0003	0.0060	0.0018	0.0005	0.0000
110				91.88%	6.41%	0.84%	0.03%	0.60%	0.18%	0.05%	0.00%
		1,429,647		1,080,576	161,071	116,661	28,346	18,918	12,697	9,029	2,349
111				75.58%	11.27%	8.16%	1.98%	1.32%	0.89%	0.63%	0.16%
		$ 964,543		$ 752,591	$ 99,236	$ 58,061	$ 11,662	$ 18,918	$ 12,697	$ 9,029	$ 2,349
112				78.03%	10.29%	6.02%	1.21%	1.96%	1.32%	0.94%	0.24%
		1.00		0.8905	0.1023	0.0066	0.0006	(0.0002)	0.0001	-	-
113				89.05%	10.23%	0.66%	0.06%	-0.02%	0.01%	0.00%	0.00%
		1.00		-	0.7751	0.1960	0.0068	0.0156	0.0047	0.0017	0.0000
114				0.00%	77.51%	19.60%	0.68%	1.56%	0.47%	0.17%	0.00%
		1.00		0.9655	0.0341	0.0004	0.0000	0.0001	-	-	-
115				96.55%	3.41%	0.04%	0.00%	0.01%	0.00%	0.00%	0.00%
		1,438,552		1,087,384	162,059	117,410	28,541	18,991	12,744	9,065	2,359
201				75.59%	11.27%	8.16%	1.98%	1.32%	0.89%	0.63%	0.16%
		122,449		86,350	16,279	15,428	4,393	-	-	-	-
202				70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
		3,323,679		2,024,051	388,962	378,482	92,831	125,443	106,963	154,646	52,302
204				60.90%	11.70%	11.39%	2.79%	3.77%	3.22%	4.65%	1.57%
		8,678,876		6,811,291	848,020	480,154	100,395	197,288	130,960	90,076	20,692
205				78.48%	9.77%	5.53%	1.16%	2.27%	1.51%	1.04%	0.24%
		8,678,876		6,811,291	848,020	480,154	100,395	197,288	130,960	90,076	20,692
206				78.48%	9.77%	5.53%	1.16%	2.27%	1.51%	1.04%	0.24%
		83,734		65,716	8,182	4,633	969	1,903	1,264	869	200
207				78.48%	9.77%	5.53%	1.16%	2.27%	1.51%	1.04%	0.24%
		6,489,133		5,122,194	626,681	342,827	70,074	147,396	97,560	67,016	15,386
208				78.93%	9.66%	5.28%	1.08%	2.27%	1.50%	1.03%	0.24%
		181,874		148,937	16,833	7,768	1,506	3,164	2,009	1,352	306
209				81.89%	9.26%	4.27%	0.83%	1.74%	1.10%	0.74%	0.17%
		181,874	-	148,937	16,833	7,768	1,506	3,164	2,009	1,352	306
214				81.89%	9.26%	4.27%	0.83%	1.74%	1.10%	0.74%	0.17%
		355,353		266,155	40,405	27,304	5,320	6,753	4,725	3,586	1,104
215				74.90%	11.37%	7.68%	1.50%	1.90%	1.33%	1.01%	0.31%
		249,972		196,182	24,425	13,830	2,892	5,682	3,772	2,594	596
216				78.48%	9.77%	5.53%	1.16%	2.27%	1.51%	1.04%	0.24%
		1.0000		0.6341	0.1180	0.1132	0.0251	0.0500	0.0357	0.0204	0.0034
217				63.41%	11.80%	11.32%	2.51%	5.00%	3.57%	2.04%	0.34%

Schedule F-1.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
Projected 12 Month Period: November 2025-October 2026
($000)

Case No.: U-21806
Exhibit No.: A-16 (SMG-2)
Schedule: F-1.1
Page: 16 of 16
Witness: SMGeller
Date: December 2024

Allocation Factors- Storage System

	Factor	Storage System	4 Residential	5 Rate GS-1	6 Rate GS-2	7 Rate GS-3	8 Rate ST	9 Rate LT	10 Rate XLT	11 Rate XXLT
		307,735,810	157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
101		100%	51.33%	9.73%	9.81%	2.66%	6.07%	6.16%	8.86%	5.37%
		223,782,881	157,808,704	29,751,571	28,194,984	8,027,623	0	0	0	0
102		100%	70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
		83,952,929	141,259	197,217	2,004,585	155,218	18,679,317	18,970,211	27,277,483	16,527,639
103		100%	0.17%	0.23%	2.39%	0.18%	22.25%	22.60%	32.49%	19.69%
		1.0000	**0.5760**	**0.1111**	**0.1070**	**0.0254**	**0.0504**	**0.0437**	**0.0632**	**0.0232**
104		100%	57.60%	11.11%	10.70%	2.54%	5.04%	4.37%	6.32%	2.32%
		1.0000	0.5662	0.1100	0.1060	0.0256	0.0505	0.0451	0.0705	0.0260
105		100%	56.62%	11.00%	10.60%	2.56%	5.05%	4.51%	7.05%	2.60%
		1.0000	0.6445	0.1192	0.1143	0.0250	0.0500	0.0343	0.0128	0.0000
106		100%	64.45%	11.92%	11.43%	2.50%	5.00%	3.43%	1.28%	0.00%
		1.0000	**0.6373**	**0.1221**	**0.1198**	**0.0301**	**0.0269**	**0.0223**	**0.0323**	**0.0094**
107		100%	63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		1,938,583	1,709,595	166,610	39,782	6,372	11,702	3,502	984	36
108		100%	88.19%	8.59%	2.05%	0.33%	0.60%	0.18%	0.05%	0.00%
		1,846,892	1,709,595	119,353	15,633	539	1,282	359	128	3
109		100%	92.57%	6.46%	0.85%	0.03%	0.07%	0.02%	0.01%	0.00%
		1.0000	0.9188	0.0641	0.0084	0.0003	0.0060	0.0018	0.0005	0.0000
110		100%	91.88%	6.41%	0.84%	0.03%	0.60%	0.18%	0.05%	0.00%
		320,036	209,795	41,494	41,072	10,450	4,721	4,203	6,207	2,094
111		100%	65.55%	12.97%	12.83%	3.27%	1.48%	1.31%	1.94%	0.65%
	$	232,231	$ 147,876	$ 29,820	$ 30,009	$ 7,300	$ 4,721	$ 4,203	$ 6,207	$ 2,094
112		100%	63.68%	12.84%	12.92%	3.14%	2.03%	1.81%	2.67%	0.90%
		-	0.89	0.10	0.01	0.00	(0.00)	0.00	-	-
113		100%	89.05%	10.23%	0.66%	0.06%	-0.02%	0.01%	0.00%	0.00%
		-	-	0.78	0.20	0.01	0.02	0.00	0.00	0.00
114		100%	0.00%	77.51%	19.60%	0.68%	1.56%	0.47%	0.17%	0.00%
		-	0.97	0.03	0.00	0.00	0.00	-	-	-
115		100%	96.55%	3.41%	0.04%	0.00%	0.01%	0.00%	0.00%	0.00%
		323,525	212,075	41,933	41,501	10,561	4,789	4,259	6,289	2,119
201		100%	65.55%	12.96%	12.83%	3.26%	1.48%	1.32%	1.94%	0.65%
		122,449	86,350	16,279	15,428	4,393	-	-	-	-
202		100%	70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
		3,323,679	2,024,051	388,962	378,482	92,831	125,443	106,963	154,646	52,302
204		100%	60.90%	11.70%	11.39%	2.79%	3.77%	3.22%	4.65%	1.57%
		8,678,876	6,811,291	848,020	480,154	100,395	197,288	130,960	90,076	20,692
205		100%	78.48%	9.77%	5.53%	1.16%	2.27%	1.51%	1.04%	0.24%
		1,638,445	1,044,143	200,068	196,208	49,246	44,068	36,520	52,852	15,340
206		100%	63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		168,990	107,693	20,635	20,237	5,079	4,545	3,767	5,451	1,582
207		100%	63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		2,093,910	1,346,919	257,719	251,956	64,016	51,321	42,538	61,564	17,876
208		100%	64.33%	12.31%	12.03%	3.06%	2.45%	2.03%	2.94%	0.85%
		23,968	15,274	2,927	2,870	720	645	534	773	224
209		100%	63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		23,968 -	15,274	2,927	2,870	720	645	534	773	224
214		100%	63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		134,210	85,319	17,836	18,262	4,346	2,122	2,048	3,089	1,189
215		100%	63.57%	13.29%	13.61%	3.24%	1.58%	1.53%	2.30%	0.89%
		45,225	28,821	5,522	5,416	1,359	1,216	1,008	1,459	423
216		100%	63.73%	12.21%	11.98%	3.01%	2.69%	2.23%	3.23%	0.94%
		-	0.6341	0.1180	0.1132	0.0251	0.0500	0.0357	0.0204	0.0034
217		100%	63.41%	11.80%	11.32%	2.51%	5.00%	3.57%	2.04%	0.34%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Information Technology Operations O&M Expense
For the Years 2023, 2024, 2025 and Test Year 12 Months Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-17 (SHB-1)
Page: 1 of 2
Witness: SHBaker
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Historical			Projected				
Line No.	Description	12 Months Ended 12/31/2023	12 Months Ending 12/31/2024	12 Months Ending 12/31/2025	2 Months Ending 12/31/2025	10 Months Ending 10/31/2026	12 Months Test Year	12 Months Ending 12/31/2026	Source
1	**Information Technology**	**$ 24,323**	**$ 26,062**	**$ 28,503**	**$ 4,750**	**$ 25,182**	**$ 29,933**	**$ 30,219**	
	Labor	6,229	5,807	6,535	1,089	5,446	6,535	6,535	
	Contracts	12,267	13,497	14,969	2,495	13,904	16,399	16,685	
	Material	1,131	847	907	151	755	907	907	
	Contractor	4,124	5,076	5,250	875	4,375	5,250	5,250	
	Non-Labor Overheads	-	-	-	-	-	-	-	
	Non-Labor Other	571	834	842	140	702	842	842	
2	**Security**	**$ 4,015**	**$ 5,160**	**$ 6,825**	**$ 1,138**	**$ 5,688**	**$ 6,825**	**$ 6,825**	
	Labor	1,641	2,450	2,885	481	2,404	2,885	2,885	
	Contracts	1,471	2,033	2,733	456	2,278	2,733	2,733	
	Material	10	4	-	-	-	-	-	
	Contractor	844	471	1,011	168	842	1,011	1,011	
	Non-Labor Overheads	-	-	-	-	-	-	-	
	Non-Labor Other	50	202	197	33	164	197	197	
3	**Total Operations O&M Expenses**	**$ 28,338**	**$ 31,222**	**$ 35,328**	**$ 5,888**	**$ 30,870**	**$ 36,758**	**$ 37,044**	
	Labor	7,870	8,258	9,420	1,570	7,850	9,420	9,420	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
For the Years 2023, 2024, 2025 and Test Year 12 Months Ending October 31. 2026
($000)

Case No.: U-21806
Exhibit No.: A-17 (SHB-1)
Page: 2 of 2
Witness: SHBaker
Date: December 2024

Line No.	Description	(a)	(b) Actual 12 Mos Ending Dec 31, 2023	(c) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2023	(d) Merit & Inflation 12 Mos Ending Dec 31, 2024	(e) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	(f) Merit & Inflation 12 Mos Ending Dec 31, 2025	(g) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	(h) Merit & Inflation 10 Mos Ending Oct 31, 2026	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending Oct 31, 2026
					(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	**Information Technology**		**24,323**	**6,229**	**199**	**5,807**	**139**	**5,947**	**124**	**5,147**	**29,933**
	Labor		6,229	6,229	199	5,807	139	5,947	124	-157	6,535
	Contracts		12,267		0		0		0	4,132	16,399
	Material		1,131		0		0		0	-225	907
	Contractor		4,124		0		0		0	1,126	5,250
	Non-Labor Overhead		0		0		0		0	0	0
	Non-Labor Other		571		0		0		0	271	842
2	**Security**		**4,015**	**1,641**	**52**	**2,450**	**59**	**2,509**	**52**	**2,647**	**6,825**
	Labor		1,641	1,641	52	2,450	59	2,509	52	1,081	2,885
	Contracts		1,471		0		0		0	1,262	2,733
	Material		10		0		0		0	-10	0
	Contractor		844		0		0		0	167	1,011
	Non-Labor Overhead		0		0		0		0	0	0
	Non-Labor Other		50		0		0		0	147	197
3	**Total Operations O&M Expense**		**28,338**	**7,870**	**252**	**8,258**	**198**	**8,456**	**176**	**7,794**	**36,758**
	Labor		7,870	7,870	252	8,258	198	8,456	176	924	9,420
	Contracts		13,738	0	0	0	0	0	0	5,394	19,132
	Material		1,142	0	0	0	0	0	0	-235	907
	Contractor		4,968	0	0	0	0	0	0	1,293	6,261
	Non-Labor Overhead		0	0	0	0	0	0	0	0	0
	Non-Labor Other		621	0	0	0	0	0	0	418	1,039

Notes

	12-Mo Ending 2024	12-Mo Ending 2025	10-Mo Ending 2026
Annual inflation rates per Company witness Rayl	3.2%	2.4%	2.5%
Number of months in the period	12	12	10
Pro-rated inflation rate	3.2%	2.4%	2.1%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Historical 13 Month Average of IT Cloud Computing Prepaid Balance
For the years 2023 - 13 months balance ending June 30, 2024
Gas Allocation

Case No.: U-21806
Exhibit No.: A-18 (SHB-2)
Page: 1 of 2
Witness: SHBaker
Date: December 2024

Line No.	(a) Description	(b) Bal. Ended 6/30/2023	(c) Bal. Ended 7/31/2023	(d) Bal. Ended 8/31/2023	(e) Bal. Ended 9/30/2023	(f) Bal. Ended 10/31/2023	(g) Bal. Ended 11/30/2023	(h) Bal. Ended 12/31/2023	(i) Bal. Ended 1/31/2024	(j) Bal. Ended 2/29/2024	(k) Bal. Ended 3/31/2024	(l) Bal. Ended 4/30/2024	(m) Bal. Ended 5/31/2024	(n) Bal. Ended 6/30/2024	(o) 13 mos. Average
1	**IT Cloud Computing Prepaid**	$ (4,508,233)	$(4,265,049)	$(3,836,559)	$ (3,489,259)	$(2,822,343)	$(2,551,776)	$(2,236,121)	$(5,497,972)	$(6,895,220)	$(6,964,632)	$(6,303,362)	$(5,559,164)	$(4,811,480)	**$ (4,595,475)**
2	**Total**	**$ (4,508,233)**	**$(4,265,049)**	**$(3,836,559)**	**$ (3,489,259)**	**$(2,822,343)**	**$(2,551,776)**	**$(2,236,121)**	**$(5,497,972)**	**$(6,895,220)**	**$(6,964,632)**	**$(6,303,362)**	**$(5,559,164)**	**$(4,811,480)**	**$ (4,595,475)**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected 13 Month Average of IT Cloud Computing Prepaid Balance
For the years 2025 - 13 months balance ending October 31, 2026
Gas Allocation

Case No.: U-21806
Exhibit No.: A-18 (SHB-2)
Page: 2 of 2
Witness: SHBaker
Date: December 2024

Line No.	(a) Description	(b) Bal. Ending 10/31/2025	(c) Bal. Ending 11/30/2025	(d) Bal. Ending 12/31/2025	(e) Bal. Ending 1/31/2026	(f) Bal. Ending 2/28/2026	(g) Bal. Ending 3/31/2026	(h) Bal. Ending 4/30/2026	(i) Bal. Ending 5/31/2026	(j) Bal. Ending 6/30/2026	(k) Bal. Ending 7/31/2026	(l) Bal. Ending 8/31/2026	(m) Bal. Ending 9/30/2026	(n) Bal. Ending 10/31/2026	(o) 13 mos. Average
1	**IT Cloud Computing Prepaid**	$ 6,474,099	$ 5,148,789	$ 4,419,187	$ 10,927,025	$ 10,132,992	$ 9,229,875	$ 8,963,923	$ 7,679,718	$ 7,342,134	$ 7,675,243	$ 6,543,440	$ 5,829,093	$ 4,791,441	**$ 7,319,766**
2	**Total**	**$ 6,474,099**	**$ 5,148,789**	**$ 4,419,187**	**$ 10,927,025**	**$ 10,132,992**	**$ 9,229,875**	**$ 8,963,923**	**$ 7,679,718**	**$ 7,342,134**	**$ 7,675,243**	**$ 6,543,440**	**$ 5,829,093**	**$ 4,791,441**	**$ 7,319,766**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Information Technology Investments O&M Expenses
For the Years 2023, 2024, 2025 and Test Year 12 Months Ending October 31,2026
($000)

Case No.: U-21806
Exhibit No.: A-19 (SHB-3)
Page: 1 of 2
Witness: SHBaker
Date: December 2024

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2023	(c) 12 Months Ending 12/31/2024	(d) 12 Months Ending 12/31/2025	(e) Projected 2 Months Ending 12/31/2025	(f) 10 Months Ending 10/31/2026	(g) 12 Months Test Year	(h) 12 Months Ending 12/31/2026	(i) Source
	Investments Planning	**$ 517**	**$ 606**	**$ 440**	**$ 73**	**$ 366**	**$ 440**	**$ 440**	
1	**Information Technology**	**$ 512**	**$ 601**	**$ 434**	**$ 72**	**$ 362**	**$ 434**	**$ 434**	
	Labor	344	416	434	72	362	434	434	
	Software	0	0	0	0	0	0	0	
	Material	0	0	0	0	0	0	0	
	Contractor	134	185	0	0	0	0	0	
	Non-Labor Overheads	0	0	0	0	0	0	0	
	Non-Labor Other	35	0	0	0	0	0	0	
2	**Security**	**$ 5**	**$ 5**	**$ 5**	**$ 1**	**$ 4**	**$ 5**	**$ 5**	
	Labor	5	2	5	1	4	5	5	
	Software	0	0	0	0	0	0	0	
	Material	0	0	0	0	0	0	0	
	Contractor	0	3	0	0	0	0	0	
	Non-Labor Overheads	0	0	0	0	0	0	0	
	Non-Labor Other	0	0	0	0	0	0	0	
	Investments O&M	**$ 4,395**	**$ 5,709**	**$ 9,580**	**$ 3,127**	**$ 14,381**	**$ 17,508**	**$ 17,257**	
3	**Information Technology**	**$ 3,876**	**$ 5,094**	**$ 9,067**	**$ 3,042**	**$ 13,773**	**$ 16,814**	**$ 16,527**	
	Labor	1,105	2,213	4,213	1,024	4,507	5,531	5,408	
	Software	451	538	598	180	2,913	3,093	3,496	
	Material	129	252	300	50	381	431	457	
	Contractor	2,008	1,973	2,707	1,280	3,373	4,654	4,048	
	Non-Labor Overheads	167	69	690	185	562	746	674	
	Non-Labor Other	16	50	558	323	2,037	2,359	2,444	
4	**Security**	**$ 519**	**$ 615**	**$ 512**	**$ 85**	**$ 609**	**$ 694**	**$ 730**	
	Labor	316	310	330	55	384	439	461	
	Software	88	128	79	13	163	176	196	
	Material	5	103	0	0	0	0	0	
	Contractor	102	72	23	4	38	41	45	
	Non-Labor Overheads	7	2	43	7	21	28	25	
	Non-Labor Other	1	0	37	6	2	9	3	
5	**Total Investments O&M Expense**	**$ 4,912**	**$ 6,315**	**$ 10,019**	**$ 3,200**	**$ 14,748**	**$ 17,948**	**$ 17,697**	
	Labor	1,769	2,941	4,983	1,153	5,257	6,410	6,309	
	Software	539	665	677	193	3,076	3,269	3,691	
	Material	135	354	300	50	381	431	457	
	Contractor	2,244	2,233	2,731	1,284	3,411	4,695	4,093	
	Non-Labor Overheads	174	71	733	192	583	775	699	
	Non-Labor Other	51	50	596	329	2,039	2,368	2,447	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
For the Years 2023, 2024, 2025 and Test Year 12 Months Ending October 31,2026
($000)

Case No.: U-21806
Exhibit No.: A-19 (SHB-3)
Page: 2 of 2
Witness: SHBaker
Date: December 2024

Line No.	Description	(a)	(b) Actual 12 Mos Ending Dec 31, 2023	(c) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2023	(d) Merit & Inflation 12 Mos Ending Dec 31, 2024	(e) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	(f) Merit & Inflation 12 Mos Ending Dec 31, 2025	(g) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	(h) Merit & Inflation 10 Mos Ending Oct 31, 2026	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending Oct 31, 2026
					(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
	Investments Planning	**$**	**517**	**0**	**0**	**0**	**0**	**0**	**0**	**-77**	**440**
1	**Information Technology**	**$**	**512**		**0**		**0**	**0**	**0**	**-78**	**434**
	Labor		344		0		0		0	91	434
	Software		0		0		0		0	0	0
	Material		0		0		0		0	0	0
	Contractor		134		0		0		0	-134	0
	Non-Labor Overheads		0		0		0		0	0	0
	Non-Labor Other		35		0		0		0	-35	0
2	**Security**	**$**	**5**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**5**
	Labor		5		0		0		0	1	5
	Software		0		0		0		0	0	0
	Material		0		0		0		0	0	0
	Contractor		0		0		0		0	0	0
	Non-Labor Overheads		0		0		0		0	0	0
	Non-Labor Other		0		0		0		0	0	0
	Investments O&M	**$**	**4,395**	**0**	**0**	**0**	**0**	**0**	**0**	**13,113**	**17,508**
3	**Information Technology**	**$**	**3,876**	**0**	**0**	**0**	**0**	**0**	**0**	**12,938**	**16,814**
	Labor		1,105		0		0		0	4,427	5,531
	Software		451		0		0		0	2,642	3,093
	Material		129		0		0		0	301	431
	Contractor		2,008		0		0		0	2,645	4,654
	Non-Labor Overheads		167		0		0		0	579	746
	Non-Labor Other		16		0		0		0	2,343	2,359
4	**Security**	**$**	**519**	**0**	**0**	**0**	**0**	**0**	**0**	**175**	**694**
	Labor		316		0		0		0	123	439
	Software		88		0		0		0	88	176
	Material		5		0		0		0	-5	0
	Contractor		102		0		0		0	-60	41
	Non-Labor Overheads		7		0		0		0	22	28
	Non-Labor Other		1		0		0		0	8	9
5	**Total Investments O&M Expense**	**$**	**4,912**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 13,036**	**$ 17,948**
	Labor		1,769	0	0	0	0	0	0	4,641	6,410
	Software		539	0	0	0	0	0	0	2,730	3,269
	Material		135	0	0	0	0	0	0	296	431
	Contractor		2,244	0	0	0	0	0	0	2,451	4,695
	Non-Labor Overheads		174	0	0	0	0	0	0	601	775
	Non-Labor Other		51	0	0	0	0	0	0	2,317	2,368

Notes

	12-Mo Ending 2023	12-Mo Ending 2024	9-Mo Ending 2025
	0.0%	0.0%	0.0%
Number of months in the period	12	12	9
Pro-rated inflation rate	0.0%	0.0%	0.0%

Schedule B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Information Technology
Summary of Actual & Projected Gas and Common Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (SHB-4)
Schedule: B-5.1
Page: 1 of 2
Witness: SHBaker
Date: December 2024

Line No.	(a) Description	(b) Historical 12 Mos Ended 12/31/2023	(c) Capital Expenditures Projected Bridge Year 12 Mos Ending 12/31/2024	(d) Projected Bridge Year 10 Mos Ending 10/31/2025	(e) Projected Bridge Year 22 Mos Ending 10/31/2025	(f) Projected Test Year 12 mos. Ending 10/31/2026
1	**Corporate**	**775**	**684**	**1,136**	**1,820**	**1,187**
	Labor	101	436	688	1,124	695
	Software	98	111	0	111	0
	Materials	0	0	10	10	38
	Contractor	488	117	63	180	75
	Non-Labor Overhead	26	4	63	67	56
	Non-Labor Other	62	15	311	327	323
	Contingency	0	0	0	0	0
2	**Customer**	**1,096**	**686**	**2,550**	**3,235**	**2,371**
	Labor	214	126	1,122	1,249	925
	Software	3	78	0	78	0
	Materials	9	0	0	0	0
	Contractor	714	436	736	1,172	872
	Non-Labor Overhead	55	15	88	103	79
	Non-Labor Other	101	30	603	633	496
	Contingency	0	0	0	0	0
3	**Electric & Gas Shared**	**2,020**	**1,943**	**591**	**2,534**	**586**
	Labor	403	995	165	1,159	190
	Software	412	213	0	213	0
	Materials	22	99	20	119	32
	Contractor	902	531	222	753	168
	Non-Labor Overhead	74	13	30	43	40
	Non-Labor Other	206	93	154	247	155
	Contingency	0	0	0	0	0
4	**Gas**	**4,535**	**9,811**	**11,741**	**21,552**	**10,180**
	Labor	330	1,499	2,651	4,150	2,930
	Software	1,592	1,198	2,937	4,135	1,123
	Materials	994	949	329	1,278	2,753
	Contractor	1,323	5,583	3,710	9,292	1,393
	Non-Labor Overhead	69	40	587	627	328
	Non-Labor Other	226	543	1,527	2,069	1,653
	Contingency	0	0	0	0	0
5	**IT/Digital Foundation**	**12,847**	**12,734**	**8,946**	**21,680**	**32,467**
	Labor	926	1,827	931	2,758	4,111
	Software	3,784	534	68	602	7,448
	Materials	6,291	6,202	5,953	12,156	9,590
	Contractor	1,423	3,642	1,441	5,083	8,182
	Non-Labor Overhead	75	91	110	201	588
	Non-Labor Other	349	438	442	880	2,549
	Contingency	0	0	0	0	0
6	**Security**	**6,348**	**6,188**	**3,762**	**9,950**	**3,902**
	Labor	1,196	709	692	1,401	392
	Software	203	502	73	576	1,335
	Materials	1,148	1,155	1,336	2,491	1,039
	Contractor	3,293	3,589	1,131	4,720	686
	Non-Labor Overhead	73	7	285	292	219
	Non-Labor Other	435	226	244	470	230
	Contingency	0	0	0	0	0
7	**Total Information Technology Capital**	**27,620**	**32,046**	**28,724**	**60,770**	**50,693**
	Labor	3,170	5,593	6,248	11,841	9,242
	Software	6,093	2,637	3,078	5,715	9,906
	Materials	8,463	8,404	7,649	16,054	13,453
	Contractor	8,142	13,898	7,303	21,201	11,377
	Non-Labor Overhead	373	169	1,164	1,334	1,310
	Non-Labor Other	1,380	1,344	3,281	4,625	5,406
	Contingency	0	0	0	0	0

The Company fully plans to perform the projects included in the Information Technology cost projections, but the projections do not incorporate a specific confidence level. These costs were not projected using confidence levels. Rough Order of Magnitude (ROM) estimates have been reduced by 20% as discussed in my testimony.

Schedule B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Information Technology
Summary of Actual & Projected Gas and Common Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (SHB-4)
Schedule: B-5.1
Page: 2 of 2
Witness: SHBaker
Date: December 2024

	(a)	(b)	(c)	(d)	(e)
		Projected			
		10 mos. Ending 10/31/2024	12 mos. Ending 10/31/2025	12 mos. Ending 10/31/2026	34 mos. Ending 10/31/2026
8	**Corporate**	**380**	**1,440**	**1,187**	**3,007**
	Labor	132	993	695	1,819
	Software	111	0	0	111
	Materials	0	10	38	48
	Contractor	117	63	75	256
	Non-Labor Overhead	4	63	56	123
	Non-Labor Other	15	311	323	650
	Contingency	0	0	0	0
9	**Customer**	**587**	**2,649**	**2,371**	**5,607**
	Labor	126	1,122	925	2,174
	Software	78	0	0	78
	Materials	0	0	0	0
	Contractor	337	835	872	2,044
	Non-Labor Overhead	15	88	79	182
	Non-Labor Other	30	603	496	1,129
	Contingency	0	0	0	0
10	**Electric & Gas Shared**	**1,525**	**1,009**	**586**	**3,120**
	Labor	610	549	190	1,349
	Software	215	(2)	0	213
	Materials	99	20	32	151
	Contractor	495	259	168	922
	Non-Labor Overhead	13	30	40	83
	Non-Labor Other	93	153	155	402
	Contingency	0	0	0	0
11	**Gas**	**8,790**	**12,762**	**10,180**	**31,732**
	Labor	1,165	2,985	2,930	7,079
	Software	1,077	3,058	1,123	5,258
	Materials	949	329	2,753	4,031
	Contractor	5,115	4,178	1,393	10,686
	Non-Labor Overhead	40	587	328	955
	Non-Labor Other	445	1,624	1,653	3,723
	Contingency	0	0	0	0
12	**IT/Digital Foundation**	**10,880**	**10,800**	**32,467**	**54,147**
	Labor	1,195	1,563	4,111	6,868
	Software	439	163	7,448	8,050
	Materials	5,388	6,768	9,590	21,746
	Contractor	3,421	1,662	8,182	13,264
	Non-Labor Overhead	91	110	588	789
	Non-Labor Other	346	534	2,549	3,429
	Contingency	0	0	0	0
13	**Security**	**5,749**	**4,201**	**3,902**	**13,852**
	Labor	898	503	392	1,793
	Software	502	73	1,335	1,911
	Materials	870	1,621	1,039	3,530
	Contractor	3,270	1,451	686	5,406
	Non-Labor Overhead	7	285	219	511
	Non-Labor Other	203	267	230	699
	Contingency	0	0	0	0
14	**Total Capital**	**27,910**	**32,860**	**50,693**	**111,464**
	Labor	4,127	7,715	9,242	21,083
	Software	2,422	3,293	9,906	15,621
	Materials	7,305	8,749	13,453	29,507
	Contractor	12,754	8,447	11,377	32,578
	Non-Labor Overhead	169	1,164	1,310	2,644
	Non-Labor Other	1,133	3,493	5,406	10,031
	Contingency	0	0	0	0

The Company fully plans to perform the projects included in the Information Technology cost projections, but the projections do not incorporate a specific confidence level. These costs were not projected using confidence levels. Rough Order of Magnitude (ROM) estimates have been reduced by 20% as discussed in my testimony.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHB-5)
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Witness: SHBaker
Date: December 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
1	2023	Application Currency-Corporate Services-O&M	Software(Intangible)	Corporate	The Corporate Services initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Corporate Services adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Corporate Services are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increase in number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	-	197,073		-	-	-	-	-	-	-	-	15,664	-	15,573	-	9,043	49,821	1,227	-
2	2023	Asset Accounting Upgrade	Software(Intangible)	Corporate	The project will upgrade our current accounting asset management software to the latest version as required by the vendor and implement additional new features, ensuring continued support of a critical financial application and providing new functionality. In 2022, standard vendor support ends for the current on-premise software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial accounting and to improve stability. The current monthly allocation process has limited visibility to Company financial performance, and the upgrade provides functionality that allows more frequent allocation processes. Additionally, implementing the vendor's regulatory module eliminates the time-consuming and labor-intensive process of manual data extracts for regulatory analysis used for Cost of Service modeling. This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) eliminating the labor intensive and time-consuming process of pulling data for regulatory analysis used for Cost of Service; (3) automating manual tasks; and (4) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support. The project scope includes: (1) upgrading the vendor software from the current version to the newer version; (2) implementing new functionality that includes features for the regulatory Cost of Service analysis, additional reporting jobs scheduling, and central load error processing; and (3) populating the data lake with data from the asset accounting system for improved reporting. Alternatives considered include: (1) Upgrade to the newest cloud version of PowerPlan. This is the preferred option as it will reduce hardware and select server costs, provide more frequent software upgrades, avoid database and server upgrade, provide weekly allocation functionality, and provide new features in job scheduling, automated regression testing, and central error processing. (2) Evaluate SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would likely be more complex, cost more, and may not provide all the required features. (3) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements.	2021-09-27	2023-12-25	-0.99	4,630,550	260,286		280,417	-	-	44,283	171,596	7,737	36,803	40,267	-	-	26,233	11,887	2,146	-
3	2023	Breakthrough Employee Experience Enablement	Software(Intangible)	Corporate	Prior period adjustment.							(1,888)	(1,888)	-	-	-	-	-	-	-	-	-	-	-	-
4	2023	EHS Compliance	Software(Intangible)	Corporate	Prior period adjustment.							(1,398)	-	-	(1,962)	46	558	-	-	-	-	-	-	-	-
5	2023	Enhancements-Corporate Services-O&M	Software(Intangible)	Corporate	The Corporate Services initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from review or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	-	40,789		-	-	-	-	-	-	-	15,294	-	-	4,452	9,924	919	-
6	2023	HR Support Pack and Business Software Inc Upgrade 2022	Software(Intangible)	Corporate	Prior period adjustment.							-	-	-	-	-	-	-	6,257	-	-	8	5,880	369	-
7	2023	HR Support Pack and Business Software Inc Upgrade 2023	Software(Intangible)	Corporate	The HR Support Pack and IBS upgrade will update the SAP's system with HR Support Packs that are released annually by SAP to comply with HR and tax changes. SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll. This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations, and (2) ensuring that it can calculate and distribute payroll. The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company. As this is an upgrade of an existing system, the alternative considered was to defer the upgrade. This alternative was not chosen due to the risk of not complying with financial rules and regulations.	2022-12-26	2024-01-22	0.00	-	664,262		-	-	-	-	-	-	-	368,417	327	-	30,212	202,704	15,174	-
8	2023	IT Access Controls Governance	Software(Intangible)	Corporate	This project replaces the current software tool that manages and monitors Sarbanes-Oxley Act (SOX) compliance for SAP transactions. To comply with SOX controls, standard SAP user access is reviewed on a semi-annual schedule; sensitive access is reviewed quarterly, and emergency access management is reviewed as needed. The current solution for validating these controls is SAP's GRC (Governance, Risk and Compliance) Access Controls software application. The SAP GRC system is the backstop for the Company's IT General Controls, which ensures legal compliance. Problems with the current implementation include: (1) increased risks as the current process is manually intensive and inefficient, and so add-ons to SOX audit deficiencies; (2) custom end-to-end role it difficult and costly to maintain, including the application of Segregation of Duties; (3) difficulty meeting SOX compliance when requirements change from auditors and the Public Company Accounting Oversight Board (PCAOB); (4) incomplete reports for segregation of duties and change logs; and (5) increased risks exist when elevated access is needed in SAP production. The project will add value through: (1) reducing hundred of manual tasks that provide higher levels of automation and access optimization; (2) decreasing maintenance and upgrade costs by implementing an out-of-the-box solution without customizations; (3) increasing the ability to meet requirement changes from auditors and the Public Company Accounting Oversight Board; and (4) creating complete and accurate report capabilities. The project scope includes: (1) automating the SAP periodic user access review; (2) automating the emergency access management process; (3) displaying areas of risk and identifying how to mediate that risk; (4) tracking mitigation; and (5) converting the current rule set into the new to-be. Alternatives considered include: (1) Continue using the current application suite as is, accepting the audit risks stemming from known issues. This alternative was not selected due to the risk associated with the SAP support ending on December 31, 2027. (2) Use robotic process automation in a limited scope to automate some manual tasks and reduce errors. This alternative was not selected as it would not mitigate risks and gaps in the current tool. (3) Develop a custom solution to perform some of the work. This alternative was not selected as it would be more costly and include higher maintenance and support costs. (4) Continue applying program patches and fixes from SAP for the current tool. This alternative was not selected as it does not address or fulfill all requirements, and requires support from main external vendor, which increases support costs. (5) Replace the existing tool with a new solution. This alternative was selected as it meets Company requirements, avoids hiring two additional resources, is more cost effective in the long term, adds more process automation, and increases SOX compliance.	2020-08-31	2023-09-31	-1.00	3,693,180	710,698		108,249	103,247	-	-	-	-	-	23,072	23,072	-	-	-	-	-
9	2023	Product Family Enhancements-Corporate Capital	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from review or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	929,170	36,253		148,525	320	-	53,104	254,418	14,147	22,323	27,035	-	-	5,551	20,153	1,331	-
10	2023	Product Family Enhancements-Corporate-O&M	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from review or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	-	212,394		-	-	-	-	-	-	-	81,546	-	-	40,753	35,720	5,073	-
11	2023	ServiceNow Customer Service Management	Software(Intangible)	Corporate	Prior period adjustment.							(1,305)	(1,305)	-	-	-	-	-	-	-	-	-	-	-	-
12	2023	Talent Management Enablement	Software(Intangible)	Corporate	The project will deliver technology solution to enable best-in-class Talent Management programs and process set that are critical to achieve the Company's overarching Talent Strategy Plan. The Talent Strategy Plan is a key enabler of the company's Integrated Resource Plan (IRP), Electric Distribution Infrastructure Investment Plan (EDIIP), and Natural Gas Delivery Plan (NGDP). Effective Talent Management programs and processes are critical to develop the skills, capabilities, productivity, and experience necessary to successfully execute these plans that deliver clean, reliable, affordable energy through an exceptional customer experience. Significant technology investments are required to transform Human Resources (HR) to develop the skills and capabilities necessary to achieve the Company. This project will add value to the Company through technology that will enable: (1) fully functional integrated compensation module; (2) accelerated and targeted talent development of critical skills necessary to deliver on the Company Talent Management Enablement will deliver the best-practice technology to enable and enhance: (1) fully functional integrated talent compensation management; (2) Simplified and automated talent management process for employee lifecycle management from onboarding through Off-boarding; (3) Succession Planning and Business Continuity; (4) Career Development and Employee Retention. The scope will include: (1) implementation of each system/application; (2) integration with current systems, application and process as applicable; (3) retrofit current systems and applications to ensure a seamless end-to-end experience of HR processes; (4) delivery of mobile-capable functionality in scope processes; (5) reporting and analytics dashboards and report insights for in-scope processes. Three alternatives were considered for these Talent Management programs and processes: (1) Develop custom, internally built solutions that could meet most requirements. This alternative was not selected because a custom solution would result in higher overall costs, higher maintenance costs, fewer upgrades, and not leverage industry best practices implemented by vendor software tool. This alternative was not selected because it requires internal maintenance, increases infrastructure costs, and would have less frequent upgrades which would hinder the Company's ability to ensure processes are evolving alongside industry trends and best practices. (3) Evaluate and select cloud/SaaS solution(s) which would have lower maintenance costs, less internal maintenance than an on-premise solution, and would be built and evolved with upgrades based on industry best practices. Based on research, internal experience with successful best practice implementations, and vendor demonstrations, option three was selected.	2023-02-27	2025-12-19	-1.00	1,221,532	464,821		75,621	-	-	3,155	63,696	4,369	2,402	71,258	-	-	3,472	66,188	1,598	-
13	2023	Time Entry and Expense Reports Flash Remediation	Software(Intangible)	Corporate	Prior period adjustment.							(6)						(6)							
14	SUBTOTAL	2023 Corporate										775,658	99,376	-	100,542	487,750	26,299	61,691	588,808	36,972	-	115,724	418,376	27,856	-
15	2023	A/M Card Transaction Fees	Software(Intangible)	Customer	This project will implement a customer paid transaction in fee for all customer payments used using a credit or debit card across all Paymentus payment channels reducing generational costs associated with payment processing. The Company's customers have embraced card payment methods and at present credit and debit card payments account for 35% of payment transactions with adoption continuing to increase. Consequently, the Company incurs an annual expenditure of over $15 million to cover card payments. As customer adoption of credit and debit card payments increases, annual operating expenses will also continue to increase. This project creates value for the Company and customers by: (1) updating all payment channels to enable customers to pay a fee for debit and credit card transactions; (2) reducing operating costs for payment processing; and (3) removing card payment restrictions on small and medium business customers. The project scope includes: (1) creating new payment menu algorithms for credit/debit card payment fee charges; (2) updating auto pay functionality in all payment channels; (3) updating all payment channels to include a customer paid transaction fee when using card payment methods segmented by residential and business customers; (4) modifying billing integrations to support card transaction fee charges; and (5) educating customers regarding card transaction fee changes. Alternatives Considered include: (1) Implement a new Business Card Payment Portal which would allow the Company to distinguish between card types and charge a fee to non-residential customers who are utilizing high rebate card types. This alternative was not selected because it would require significant investment to create and maintain a separate business payment portal and the complex card rate which would minimize operating savings. (2) Implement a fee across all payment types, except autopay utilizing automated clearing house payments (ACH), in all payment channels for all customers. This alternative was not selected because implementing costs for ACH did not provide the optimal value and experience to customers. (3) Implement a fee for card payment transactions in all payment channels for all customers. This alternative was selected because it provides the best balance between achieving the project objectives, controlling costs, and optimizing value to customers.	2023-03-13	2023-12-22	35.42	1,064,704	342,156		148,597	-	-	76,064	228,457	15,501	21,535	119,755	-	-	49,439	63,342	5,666	1,317
16	2023	Application Currency-CX&O Capital	Software(Intangible)	Customer	The CX&O initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities as sociated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the CX&O adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the CX&O are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increase in number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	-	116,399		-	-	-	-	-	-	-	23,695	-	-	6,014	17,093	587	-
17	2023	Application Currency-CX&O-O&M	Software(Intangible)	Customer	The CX&O initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the CX&O adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the CX&O are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increase in number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	-	26,217		-	-	-	-	-	-	-	9,830	-	-	617	9,160	53	-
18	2023	Bill Redesign	Software(Intangible)	Customer	Prior period adjustment.							(10,881)	-	-	(16,710)	(37,879)	(2,021)	(4,272)	61,762	-	-	18,291	41,326	2,205	-
19	2023	Business Customer Interval Web Portal	Software(Intangible)	Customer	Prior period adjustment.							(16,567)	-	-	-	-	-	(10,567)	-	-	-	-	-	-	-
20	2023	Click to Chat	Software(Intangible)	Customer	This project will implement a click to chat platform, whereby customers can engage in a chat conversation with customer service agents. This solution will engage agents and customers to measure customer engagement interest and agent performance in handling chat(s) via the Consumers Energy website. The company currently does not offer live chat on our website. Today, more than 41% of customers expect live chat and more than 50% who use mobile phones expect it. That number is only rising each year. 10. Power found that live chat has become the leading digital contact method for online customers; 42% of customers prefer live chat compared to just 28% for email. Currently, the only way customers can connect with the company are through phone, email, fax, or digital forms. These options are just not efficient enough and longer. This project creates value for the Company and it's customers by: (1) determining customer take rate and interest in leveraging chat as an engagement channel for Business Units of WCC and BCC originating from the owner website; (2) determine owner's customer service staff capacity to handle more than one chat's session (customer interaction over chat) at a time. Capacity may be up to 4 sessions at a time; and (3) survey customer experience. The project scope encompasses: (1) chat offer managed based on statistics and state on agent availability and wait time; (2) robust reporting; (3) customer data push based on interactions; (4) agent experience - all interactions (chat, voice, SMS) can be received via a software and allow for escalations; (5) monitoring of agent available by cross all channels (ex. voice, chat); and (6) full integration across software and backend systems. Alternatives considered include: (1) continue use of the current communication methods. This alternative was not considered because customers prefer to chat with someone in real-time and online, rather than current communication channels (Telephone and Email). (2). Develop a message response story. This alternative was not considered because it is not cost effective and does not address the problem of having the customers' requirements for instant/real-time communication. This alternative could take upwards of 12-24 hours for a response. The recommended alternative of a Click to Chat platform, described in this entry, will involve utilizing industry best-practice vendors for a purpose-built solution to meet the requirements of our customers.	2021-07-26	2024-05-27	-1.00	911,602	10,504		45,681	-	-	4,013	26,812	292	14,565	375	-	-	-	351	24	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025, and 2026
Information Technology Department

REDACTED

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION OF O&M SPEND FOR APPICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
21	2023	Compile Billing Automation	Software(intangible)	Customer	Prior period adjustment.							(195)	-	-	-	-	-	(157)	-	-	-	-	-	-	-
22	2023	Customer Self-Service Mobile Application	Software(intangible)	Customer	Prior period adjustment.							(3,509)	(3,509)	-	-	-	-	-	3,827	3,829	-	-	-	(2)	-	-
23	2023	Customer Self-Service Online Work Scheduling	Software(intangible)	Customer	The Online Work Scheduling project will implement online, self-service work order scheduling for various types of short-cycle work to enable customers to schedule work online, rather than contacting the contact center. Currently customers must call the contact center to schedule work and obtain updates given a lack of online self-service capabilities. To stay informed customers are required to contact the contact center, and often requires multiple calls per work request. In addition, once work is completed customers do not receive confirmation that the work has been completed or what work was completed, which may also result in additional inbound customer calls. This inefficiencies require multiple inbound calls, which often results in customer dissatisfaction. The Company and its customer will see value through this project by: (1) implementing self-service capabilities for customers to schedule service work, (2) reducing calls into contact centers, (3) improving the digital experience within the Company's customer portal, (4) improving quality of utility service work through timely customer surveys based on work completed, (5) improving work efficiency by supplying blocks of time for specific work order types, (6) improving overall customer experience as customers can utilize channel of choice, and (7) enabling future initiatives supporting customer site work by developing the technical and business process foundation for other initiatives to expand upon. The project scope includes: (1) updating the online customer self-service portal to include work order scheduling, (2) establishing channel of choice options for scheduled work order confirmation notifications, and (3) automating scheduling of work orders in SAP and other back-end systems. Alternatives considered include: (1) developing a form on the Company's web portal for customers to complete and send to a monitored email box, (2) purchasing a third-party cloud solution to host a portal for customers to schedule work orders, (3) displaying a map of service areas with a number for customers to call their local dispatch area, and (4) enhancing the current customer self-service portal to include scheduling work orders. The first and third alternatives were not selected because they will degrade the customer experience and require additional manual process steps and work, introducing waste to manage additional processes to schedule the work order. The second alternative was not selected due to the high cost of integrating a new solution with the existing customer platform and back-end systems and increasing ongoing maintenance and support costs. The fourth alternative was selected because it improves customer experience through self-service, utilizes the existing customer self-service portal, increases process efficiency for scheduling work orders, and minimizes increases for ongoing maintenance and support costs.	2021-06-28	2024-08-29	-1.00	1,846,364	279,779		6,346	6,346	-	-	-	-	-	5	5	-	-	-	-	-
24	2023	EnergyAssistance Enhancements and Maintenance Annual Updates	Software(intangible)	Customer	The Energy Assistance Enhancements and Maintenance Annual Updates project, formerly known as Consumers Affordable Resource for Energy (CARE) project, will implement software changes to offer energy assistance to low-income customers and streamline the process for the assistance payment. This is accomplished through improved user interface and updates to SAP to process various requests. Upcoming modifications will be identified following an ongoing and annual review of requests to prioritize the list of changes. Each grant year, Department of Health and Human Services (The project will provide the following value: (1) complete modifications to internal SAP application and Agency Portal to receive LIHEAP funding, which can be used to provide customers the bill credits and arrears forgiveness; (2) improve the data within the assistance agencies portal, thereby making it easier to assist customers in need of LIHEAP funding; and (3) complete modifications to customer facing platforms. The project scope includes: (1) updating the enrollment and status process; (2) allowing for flat monthly bills; (3) improving reporting; (4) updating the amount to give new plans; (5) satisfy legislative/regulatory requirements for the annual grant rule changes required by the Department of Health and Human Services and Michigan Public Service Commission; (6) updating PC #96 (funding process); and (7) updating CE PA 58 Funds to Utility to enhance Agency Self-Service. Alternatives considered included: (1) continue with current process, which would lead to loss of grant funding, thus decreasing or eliminating energy assistance dollars for customers; (2) transfer administration of Energy Assistance Programs to a third party organization, which would remove ownership and stability into the health of the program while increasing administrative costs; and (3) make annual updates to the application, which will allow agencies to easily enroll customers on assistance programs and allow placement of hold to stop or prolong credit activity until assistance decisions are granted. Option 3 was selected since it provides customers more proactive energy assistance to customers and prevents loss of grant funds. All the changes are internal to SAP and Agency Portal related, therefore a cloud or third party alternative is not viable. Additionally, enhancing existing Agency Portal for a new application would increase costs beyond that of the routine upgrades.	2023-01-01	2023-12-31	0.00	-	221,945		-	-	-	-	-	-	-	85,213	-	-	41,703	38,606	4,904	-
25	2023	Enhancements - Customer Experience and Operations- Cap	Software(intangible)	Customer	The CX&O Initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the CX&O Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-scale software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software applications investments for CX&O. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience Operations, Applications Support and Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this fund/grant governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	798,924	75,876		225,419	-	8,668	96,022	89,878	10,065	20,810	26,557	4,480	-	3,315	18,040	722	-
26	2023	Enhancements- CX&O-Capital	Software(intangible)	Customer	The CX&O Initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the CX&O Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-scale software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software applications investments for CX&O. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this fund/grant governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	895,691	146,167		287,138	497	-	29,383	171,699	13,508	72,251	51,868	709	-	5,935	40,798	3,579	847
27	2023	Enhancements- CX&O-O&M	Software(intangible)	Customer	The CX&O Initiative will utilize O&M funding to make enhancements to existing technology and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for small-effort technology changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation. Failure to make these changes or to update aging technology can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of technology enhancements in the CX&O Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-scale technology efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT technology investments for CX&O. The scope of technology enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this fund/grant governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	-	146,302		-	-	-	-	-	-	-	56,171	-	-	17,610	36,100	2,461	-
28	2023	Flexible and Advanced Payment Options	Software(intangible)	Customer	The project will address customer concerns regarding existing payment plan options. The effort will create payment plans for customers to increase successful payments and accommodate specific needs of customers requiring assistance paying their energy bill. Currently, the Company payment arrangement offerings are insufficient or lack flexibility to support the needs of customers. On average, Hello Pay Customers account for 87%, 000 call into contact centers to resolve payment plan related concerns. Existing payment plan options have a 5% success rate. In order to increase customer satisfaction, reduce calls to contact centers, and reduce payment plan defaults the Company needs to offer payment challenged customers easier and more flexible payment options. The project creates value to both the Company and its customers through: (1) improved customer experience by ensuring customers can set up payment programs within the channel of their choice (2) reduced default on for repeat callers by enabling customers to be successful in payment programs, (3) reduced active arrears by removing unnecessary risk and offering options based on customers The scope of this project includes: (1) identifying changes for new and existing payment plans to increase successful customer payments, (2) update IVR/SP with eligibility rules for payment plans, (3) updating the customer self-service portal and IVR to align with available payment options and self-service capability, (4) reviewing customer feedback to determine the right payment plans to support their needs, (5) implementing an installment plan quick on the digital platform enabling customers to self-serve and select the best plan for them, and (6) improving input screens for Customer Service Representatives (CSR) surrounding payment plans. The alternatives considered include: (1) Enable only CSR resources to set up customized payment plans. This was not selected as the customer would still have to call in, preventing call reduction in our contact centers. (2) Utilize a third-party program for all customers needing payment assistance. This was not chosen as the pilot completed also need limited success as a small portion of customers chose to stay on the program. (3) Implement changes to Payment Assistance plans. This was selected as it provides the customer with multiple options to pay their bill while supporting the Company's cost savings goals.	2021-07-26	2023-10-12	-0.95	1,342,617	368,734		210,698	-	-	13,662	167,051	12,567	7,378	18,803	-	-	4,549	13,212	1,041	-
29	2023	Product Family Enhancements-Customer-Capital	Software(intangible)	Customer	The Customer Initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-scale software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software applications investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this fund/grant governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	246,238	19,376		86,832	-	-	11,217	67,777	4,993	2,846	6,782	-	-	4,885	1,705	191	-
30	2023	Product Family Enhancements-Customer-O&M	Software(intangible)	Customer	The Customer Initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-scale software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software applications investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this fund/grant governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	-	386,882		-	-	-	-	-	-	-	146,914	-	-	8,218	129,078	9,618	-
31	2023	Rates Case Implementation	Software(intangible)	Customer	Prior period adjustment.							-	-	-	-	-	-	-	4,784	-	-	139	4,372	274	-
32	2023	SiteCore Secondary Upgrade 2023	Software(intangible)	Customer	The SiteCore Upgrade project will refresh all components of the website hosting, delivery, search, and analytics applications to add new features and improve search capabilities. Sitecore is the content management application for consumersenergy.com website, a channel many customers use for accessing account information and bill payment. The application requires regular upgrades to ensure system reliability, take advantage of new application features, and improve the customer's website experience. The Sitecore upgrade provides these four benefits: (1) maintains currency with the web hosting application framework; (2) allows business users to make use of new features and functionality; (3) neutralizes continually evolving cyber threats; and (4) continuously improves customer experience using consumersenergy.com. The project scope includes: (1) upgrading the Sitecore core, three management software components, and delivery and allowing the use of new features and functionality; (2) upgrading the Mongo database, which provides the analytics functionality within Sitecore. Alternatives considered included: (1) implement a two-year upgrade cycle. This alternative was not chosen due to the rapidly changing features set being developed by the vendor, as well as not being able to position the Company to keep up with constantly changing cyber threats; (2) Purchase an existing cloud solution. The cloud solution was not chosen as the cost/benefit analysis revealed this option is not viable at the time of filing; and (3) Annually upgrade the existing Sitecore platform. This alternative was chosen as it provides the functionality and stability needed, is cost effective compared to alternatives, and mitigates cyber security risks.	2022-01-03	2023-10-20	-1.00	-	81,264		-	-	-	-	-	-	-	10,470	-	54	19,788	8,760	1,869	-
33	2023	SiteCore Upgrade	Software(intangible)	Customer	Prior period adjustment.							-	-	-	-	-	-	-	594	-	-	594	-	-	-
34	SUBTOTAL	2023 Customer										1,095,719	1,334	8,648	211,652	719,700	54,105	101,100	647,402	9,123	58	101,025	421,942	33,194	2,166
35	2023	Application Currency-Electric & Gas Shared-Capital	Electric & Gas Shared		The Electric and Gas operations initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risks/impacts of performing the upgrade ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Electric and Gas operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	71,191	1,596		22,838	-	-	10,586	8,568	1,160	2,529	559	-	-	195	333	30	-
36	2023	Application Currency-Electric & Gas Shared-O&M	Software(intangible)	Electric & Gas Shared	The Electric and Gas Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risks/impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Electric and Gas Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	-	5,624		-	-	-	-	-	-	-	2,159	-	-	853	1,159	147	-
37	2023	Application Currency-Operational Technology-Capital	Software(intangible)	Electric & Gas Shared	The Operational Technology initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risks/impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timings of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	54,302	69,218		17,430		17,430					24,226		24,226				

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025, and 2026
Information Technology Department

REDACTED

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	RERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAP ITALIZ ED FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION OF O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
38	2023	Application Currency-Operational Technology-O&M	Software(intangible)	Electric & Gas Shared	The Operational Technology initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor support that version, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of application throughout application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protection; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	-	34,257		-	-	-	-	-	-	-	13,153	-	-	-	13,153	-	-
39	2023	Application Currency-Operational Technology-O&M	Software(intangible)	Electric & Gas Shared	The Operational Technology initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor support that version, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of application throughout application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protection; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	-	5,678		-	-	-	-	-	-	-	2,129	-	-	1,893	90	146	-
40	2023	Application Currency-Operations-Capital	Software(intangible)	Electric & Gas Shared	Prior period adjustment.							(6,331)	-	-	(3,114)	(1,191)	(282)	(1,644)	-	-	-	-	-	-	-
41	2023	Application Currency-Operations-O&M	Software(intangible)	Electric & Gas Shared	The Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor support that version, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Operations adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protection; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	-	555		-	-	-	-	-	-	-	208	-	-	158	38	12	-
42	2023	Application Currency-TEOS-O&M	Software(intangible)	Electric & Gas Shared	The TEOS initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor support that version, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the TEOS adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protection; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the TEOS are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	-	78,242		-	-	-	-	-	-	-	30,040	-	-	9,627	19,657	757	-
43	2023	Enhancements-Operations-Capital	Software(intangible)	Electric & Gas Shared	The Operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software applications changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Operations Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software applications and investments for Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering, Customer Energy Management, Electric Grid Integration, and Fleet. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	598,611	27,679		139,817	-	2,758	44,383	80,459	7,257	24,960	9,688	-	-	6,369	2,636	501	181
44	2023	Enhancements-Operations-O&M	Software(intangible)	Electric & Gas Shared	The Operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Operations Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software applications and investments for Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering, Customer Energy Management, Electric Grid Integration, and Fleet. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	-	132,075		-	-	-	-	-	-	-	42,905	2,855	-	14,550	22,772	2,695	33
45	2023	Enhancements-TEOS-Capital	Software(intangible)	Electric & Gas Shared	The TEOS initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software applications changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the TEOS Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software applications and investments for TEOS. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering, Customer Energy Management, Electric Grid Integration and Fleet . Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this fund rigure governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	540,722	41,913		146,338	-	-	30,481	84,721	8,532	20,599	14,669	-	-	8,757	5,002	910	-
46	2023	Enhancements-TEOS-O&M	Software(intangible)	Electric & Gas Shared	The TEOS initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the TEOS Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for TEOS. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering, Customer Energy Management, Electric Grid Integration, and Fleet. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this fund rigure governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	-	128,877		-	-	-	-	-	-	-	48,323	28	-	11,631	33,345	3,248	72
47	2023	Field Contractor Work Management Technology Enablement	Software(intangible)	Electric & Gas Shared	The project provides the ability to electronically manage contractor work and increases accuracy and timeliness of information processing for field work deliverables. This project additionally creates new opportunities to measure and optimize field service processes supporting customer on-time delivery goals. Contractor field employees use manual, paper-based processes and generic communication technologies (phone, radio, email, collaboration sites) to perform work for the Company. Due to the non-electronic format, inaccuracy, and delay of information processing there are negative impacts to the availability and accuracy of work status. This limits the opportunity to measure and optimize field work processes that support customer on-time delivery and other goals. The project will add value by: (1) improving on-time delivery of customer work by providing electronic work order information to contractors; (2) improving customer satisfaction through efficiency in scheduling work and reporting on the progress electronically; (3) increasing safety by tracking work and contractor status providing visibility into the last known location of the contractor; (4) improving material management; (5) making it easier to reweemergent work to contractors to balance workloads and meet customer commitments; and (6) enabling real-time updates to work order information, increasing data accuracy and reducing invoice reconciliation time. The project scope includes: (1) identifying requirements for a Bring Your Own Device (BYOD) field contractor work management technology solution and process; (2) developing, configuring, and testing interfaces, hardware, and software for the solution; (3) implementing the solution and process for the following work groups: Electric High Voltage Distribution (HVD), Electric Low Voltage Distribution (LVD), Mutual Assistance, Forestry, Distribution Gas Code Compliance, and Substation Operations Construction Work; (4) updating the following vendor contract types to support BYOD field contractor work management: zone, specific bid, and fiery, electric storm, and mutual assistance; and (5) training field contractors and the new technology and processes. The alternatives considered included: (1) Continue with the current paper-based process. This alternative was not selected because this approach does not allow for the timely, data-driven work management metrics required to improve service to customers. (2) Use the current Company mobile application. This alternative was not selected because the solution is not expected to receive long-term investments by the vendor and the mobile application would require more upfront investment than the proposed option. (3) Use a third-party platform options such as ServiceNow. This alternative was not selected because contractors would not be able to leverage the benefits and integrations with the existing platforms and it would require additional new integrations. (4) Provide Company-owned devices to contractors. This alternative was not selected because the investment in hardware and procurement of on-boarding and off-boarding of devices to contractors, and training and change management is cost prohibitive and introduces a risk of the loss of control of information security and corporate assets. Leveraging the existing field work management solution was chosen because it uses existing well-developed functionality while leveraging cloud-based, BYOD capabilities to move short-term and long-term contractor/fo mapper process assto the established, hardened work management system.	2021-05-24	2024-12-31	-0.93	2,168,316	624,732		130,188	-	-	31,091	62,050	5,727	11,315	8,187	-	1,002	274	6,464	448	-
48	2023	Field Mapping and Graphics	Software(intangible)	Electric & Gas Shared	The project will implement a solution for the mobile field mapping and data collection that can search and view facility map data, view work order designs, and create work order as-built construction drawings in the field. This software technology increases process efficiency by consolidating field graphics functionality, reducing IT complexity and testing, and increasing adoption in the field through ease of use. In addition, it allows the Company to move to a supported application platform and retire the unsupported ArcPad solution. The current mapping and graphics application was implemented in 2002 and is no longer sold or supported in any capacity, and the custom solutions developed for the application cannot be changed. Due to the imposed accuracy of the CE landbase (streets, political boundaries, etc.), the outdated electric maps that are referencing that data causes the map to be unreadable which causes a safety issue. Additionally, field employees have considerable challenges when attempting to use the software due to awkward, arrugid interface, and dated processes. The project will add value by: (1) providing more accurate geospatial data, including facility map data, pre-construction designs, and as-built construction drawings; (2) consolidating daily tasks into a more simplified process; (3) validating data to ensure quality issue; (4) enabling the adoption of the Geographic Information System (GIS) standard; and (5) making mapping and graphics data available on field devices. The project scope includes: (1) installing a new mobile field mapping and graphics application; (2) creating the ability to search and view the facility map data in GIS format along with the ability to search by address; (3) viewing pre-construction work order designs in GIS format; and (4) creating as-built construction drawings and (5) format for assigned work orders. Four alternatives were evaluated and three were determined no viable for the project: (1) Continue maintaining the current ArcPad application. This option was not selected because the Company is no longer able to make changes to the ArcPad application to mitigate issues if the application has critical defects. A total failure of the application could prevent field crews back to paper-based facility maps, risking safety using stale, outdated data, or requiring the creation of as-built construction drawings on paper documents. (2) Use the Adobe or Snagit applications for creating as-built construction drawings. This option was not selected because field users would have to use one solution for viewing facility maps and use rudimentary drawing tools like Ads Be or Snagit for creating as-built construction drawings. This option was also not selected because it introduces additional costs due to the complexity and customization needed to integrate the applications. (3) Build a custom Mapping and Graphics solution. This option was not selected as existing industry solutions are available at a much lower cost with much less risk. (4) Implement right the new field mapping and graphics software was selected as this option will consolidate field graphics functionality into an efficient process and provide a current, supported solution	2020-11-30	2025-08-25	-0.71	4,400,537	70,897		280,798	372	-	91,829	115,430	9,881	63,297	13,853	-	-	9,069	4,116	668	-
49	2023	Field Network Director	Software(intangible)	Electric & Gas Shared	Design, develop, test and implement Cisco's Field Network Director (FND). FND is a network management solution for Field Area Network (FAN). The solution is necessary for the management of the modems that have been selected as the new Company standard for modems, as the previous standard modem is no longer being manufactured. The modems used for Electric and Gas Field device deployments have been discontinued by the manufacturer and the existing inventory will be exhausted by September 2021. After an extensive analysis of 6 modems, a modem was selected as the new standard, replacing the discontinued device. Configuring and managing modems manually is an ongoing, time consuming and labor intensive effort with tasks that include: modems configuration, firmware updates and modems status analytics, exasperated by the need to apply cyber security requirements. With no centralized software to manage the modems: 1) every modem will need to be manually configured, resulting in deployment delays and/or head-count increases; 2) lack of centralized over the air device management will introduce increased cyber security risks. Modem management software is required in order to effectively introduce, monitor and manage the new modem type. Support modems configuration, operations and management with a solution that provides capability to manage the new field based communications devices from a central and platform. Purchase, install, configure and integrate Cisco's Field Network Manager (FNM) software. Alternative 1, Stock and install selected modems without implementation of the FND. This alternative was not selected as manual management of modems will require: 1) Additional FTEs (+1 in 2022, +1 in 2024); 2) cyber security vulnerabilities will not be mitigated. 3) quality will be degraded with many manual steps. Alternative 2, evaluate other hardware vendors was not selected because of the immediate need to replenish modem stock as the previous modem is no longer manufactured and current stock is expected to be depleted in September 2021, Alternative 3, to utilize Cisco Field Network Manager (FNM) Software, which is the most cost effective approach to support existing inventory of modems; support the new standard modems; automation in configured on and management upgrades in firmware, modem status analytics, and cyber security requirements through a centralized platform.	2021-09-01	2024-05-27	-1.00	1,071,760	182,548		137,172	-	-	26,793	84,777	3,361	22,841	20,454	-	-	1,529	18,820	105	-
50	2023	OSIsoft PI Historian Upgrade 2020	Software(intangible)	Electric & Gas Shared	Prior period adjustment.							5,361	3,610	1,750	-	-	-	-	-	-	-	-	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHB-5)
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Witness: SHBaker
Date: December 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALS PEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
51	2023	Product Family Enhancements-Electric & Gas Shared-Capital	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge. From review or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Electric and Gas operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operate ns Performance, Operations and Financial Reporting and Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives fro meach area that routinely evaluates and prioritizes the work and to assess requests for value using a ranked benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	113,252	-		16,338	-	-	-	8,818	23,179	2,072	2,063	-	-	-	-	-	-	-	-	-	-
52	2023	Product Family Enhancements-Electric & Gas Shared-O&M	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Electric and Gas Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operate ns Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using a ranked benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	-	28,534		-	-	-	-	-	-	-	10,955	-	-	3,837	6,388	730	-
53	2023	Service Suite Upgrade	Software(Intangible)	Electric & Gas Shared	The project will: (1) implement a new version of Service Suite Work Management that allows for easier distribution of work orders to the field, and (2) maintain a current version on a vendor supported platform for this critical enterprise application used across Operations and Engineering. The Service Suite Application is the mission critical work management software delivering work orders for customers. The current solution lacks an integrated view of traffic and a realizable dispatch work schedule. The upgrade will improve application performance by leveraging the application's current to maintain vendor support. The project will add value by: (1) implementing a new version that provides the appropriate level of vendor support for this 24x7 critical solution that provides over 100,000 work orders to the field weekly; (2) implementing Service Suite Workforce Management and migrating to cloud-based configurations that will simplify support and speed deployment of future changes; (3) providing the new feature of live traffic display on the Dispatch Application which will further improve dispatch decision making and (4) improving the readability and usability of the Dispatch Application schedule view, which will allow for a better comprehension of employees' work schedule. The scope of the project includes: (1) implementing the new version of Service Suite Workforce Management; and (2) integrating to a mobile mapping and driving directions application with Service Suite for mobile mapping on the field device to improve safety, response, usability, and supportability of the system. The alternatives considered included: (1) remaining on the current Service Suite version, which requires additional manual steps in the emergency response and work assignment; (2) creating a custom-developed solution, which increases waste and inefficiency, without the same level of Enterprise Resource Planning integration; or (3) changing the current vendor, which was not selected due to the increased complexity of migration and organizational change management. Upgrading Service Suite Field Service Management was chosen because it allows the Company to stay on the supported and familiar platform already being used in the field and provides additional business value and benefits to operations.	2022-12-26	2023-12-31	-1.00	1,077,410	103,381		345,638	-	-	-	103,445	191,196	18,730	32,102	36,183	-	-	9,915	24,448	1,820	-
54	2023	Spatial Asset Management	Software(Intangible)	Electric & Gas Shared	This initiative will implement SAP's Spatial Asset Management module. It will allow users to view assets, notifications, and orders geospatially using a map. The module will allow us to create and maintain asset maintenance plans for each segment of our gas and electric distribution networks (linear assets). We will create linear assets as technical objects (such as functional locations and equipment) and store linear data. We will enable creation of maintenance plans for these technical objects which result in notifications, maintenance orders, and measurement documents. We will enable monitoring of the condition of our linear assets, identify where there is damage or a defect (using the start point and end point and offset), and manage all types of maintenance tasks (planned, unplanned, and preventative). Currently Consumer Energy lacks spatial visualization and spatial awareness of work and assets impacting requirements for first time quality and planning the ability to plan, bundle and execute nearby work. The lack of a linear asset management capability affects the full work management value stream resulting in overproduction of asset maintenance activity such as assessments, surveys, and inspections. This project creates value for the company by: 1) providing capability in SAP to view assets, notifications, and work orders on a map, 2) providing location awareness in SAP for assets and work, 3) establishing linear asset management capability in SAP for gas and electric delivery networks, 4) enabling end-to-end map-based workflows. The scope of this project encompasses implementation in SAP of the Spatial Asset Management module. Alternatives considered include: 1) A Cloud-based risk-based asset integration between GIS and SAP. This alternative was not selected as it proves ineffective in addressing needs of the end-to-end work management value stream while increasing the technical footprint of customization. There are also performance concerns with cloud to on-premi migrations. 2) Work group centric approaches to viewing work on a map. This alternative was not selected as it does not support asset information thru the entire asset management value stream. 3) Do nothing. This alternative was not selected as this would result in increasing costs and inefficiencies in gas and electric work management. 4) The alternative to implement the Spatial Asset Management module in SAP was chosen as it expands use of a core technology investment, supports current investment in our work management value stream, and is compatible with our GIS technology.	2023-12-04	2025-11-30	-1.00	3,158,109	206,194		440,622	408,157	-	-	51,232	-	1,253	-	-	-	-	-	-	-	-
55	2023	Work Management Scheduling Analytics and Reporting	Software(Intangible)	Electric & Gas Shared	The project will implement a solution to optimize the key components of the Distribution Planning and Scheduling functions including executing, workorder intake, resource identification, work schedule creation, workhesvaluation preparation and associated work order analytics. Three primary alternatives were considered for this project: (1) Automating manual data movement across excel and current systems through Robotic Process Automation. This option was not selected because it will not meet base requirements and will not provide desired insights into whether the schedule supports operating priorities and metrics, financial scenarios, first time completion of work, and daily goals; (2) Integrating an off-the-shelf planning and scheduling system. This option is not preferred due to associated upfront and long-term costs; and (3) Implementing a hybrid of an off-the-shelf planning component with custom built scheduling functions. This is the preferred option to provide a more cost-effective and targeted fit for the organization.	2022-01-26	2024-11-20	-0.71	2,283,004	176,667		305,292	5	83	58,581	201,798	17,727	27,068	16,183	11,188	-	-	4,195	476	323	-
56	**SUBTOTAL**	**2023 Electric & Gas Shared**							**2,020,031**	**412,146**	**22,011**	**402,893**	**902,204**	**74,305**	**205,482**	**293,674**	**14,971**	**25,238**	**83,460**	**108,095**	**12,754**	**286**
57	2023	Gas Operations Field Devices For Gas Construction Employees	New Computers / Hardware	Gas	Prior period adjustment.				4	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-
58	2023	Application Currency-Gas-O&M	Software(Intangible)	Gas	The Gas Engineering and Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Gas Engineering and Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Gas Engineering and Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of these efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on (1) maintaining an optimal balance between keeping the application current and reducing failures, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	-	30,780		-	-	-	-	-	-	-	30,780	213	-	24,626	4,120	1,821	-
59	2023	Compression Digital Mobility	Software(Intangible)	Gas	Prior period adjustment.				(1,206)	-	-	-	(810)	(51)	(283)	1,194	-	-	-	870	51	273
60	2023	Corrosion Control Modernization	Software(Intangible)	Gas	This project will modernize the Corrosion Control measurement, documentation, and analysis process for Gas Transmission and Gas Distribution Corrosion Control. It will also automate the Corrosion Control process and eliminate manual data entry and paper for mthe process. The current gas pipeline corrosion control field data collection and monitoring process is antiquated and manually intensive. The existing process requires that technicians take readings from the corrosion control devices using a handheld DAH (Digital Voltmeter) and then record these readings on paper, followed by manual data entry into Inspection Manager. The results can then be further stored, processed and analyzed. This process is labor intensive and error prone, which could result in compliance issues, issues rework, and drive up labor costs. This project creates value for the Company and its customers by: (1) maximizing the entire gas pipeline corrosion control field data collection and monitoring process; (2) eliminating the manual paper process of taking and recording measurements on corrosion control devices attached to gas pipelines; (3) automating the entire process from measurement through documentation and analysis; (4) providing an integrated solution that takes the measurements and records the results in one step; (5) implementing geographical location (latitude, longitude) for every test point recorded; (6) improving accuracy and timeliness of the data collected by passing the data directly to the system of record. The project's scope includes: (1) purchasing hardware and software with related licenses needed to establish a modern electronic corrosion measurement and documentation system; (2) interfacing with the existing GIS system for test-point location data; (3) a data transfer to the new system from the work inputsystem of record, Inspect on Manager; and (4) training users in the use of the new system and deploy to all corrosion control technicians. Alternatives considered include: (1) continue with the current manual process. This option was not selected as it does not solve the issues associated with the paper-based manual process; (2) develop Consumers Energy's solution that would interface with a standard DAH and automate the current paper process using custom in-house solution. This option was not selected as it would be far too costly and time-consuming to develop in-house and a standard solution is available in the marketplace; and (3) purchase and implement a COTS (Common Off The Shelf)hardware and software solution to provide an electronic means of data measurement and collection then interface that system with the existing system of record. This option was selected as it meets the goal of automating the data collection and documentation process and eliminates the existing paper process.	2022-08-23	2024-12-27	-0.45	1,309,838	34,613		488,935	6,419	47,303	98,207	245,406	23,571	68,019	18,005	-	9,656	2,347	5,452	499	52
61	2023	ECM Project Wise	Software(Intangible)	Gas	Prior period adjustment.				-	-	-	-	-	-	-	23	-	-	-	-	-	23
62	2023	Gas Compression Digital Work Management	Software(Intangible)	Gas	The project provides work management software and digital forms for Gas Compression facilities. The current work management process for Gas Compression locations is cumbersome and largely paper based outside of desktop tasks. This manual system leads to excess waste, rework, and human error. This project provides value to the Company through: (1) increased productivity by reducing the need to return to the desktop kiosk for updates; (2) improved quality through increased accuracy of updates completed at the time and place of the work; and (3) improved safety through real-time information used at work sites rather than printed procedures. The scope of the project includes: (1) purchasing licenses to add Gas Compression users to the company's existing mobile work management software, and (2) configuring changes in SAP and the mobile work management software to replace the paper-dependent work management process with the ability to access and update maintenance, operations, and safety information at Gas Compression locations. Alternatives considered include: (1) Utilize an SAP work management solution is not preferred since it is a new solution and requires additional project and support cost. (2) Continue the manual paper-based process. Continuing the manual paper base process was not chosen because of process waste, rework, and human error. (3) Customize the existing electronic Shift Operations Management (eSOMS) mobile application to add work management functions. As a custom eSOMS mobile application was not chosen because it would require additional project cost and ongoing support budget for a custom solution that the eSOMS product was not intended to support. (4) Utilize the existing Service Suite solution currently deployed for Gas and Electric Distribution. The Service Suite solution is the preferred option because it is a proven solution at the Company and provides the mobility and digital benefits at a lower cost.	2023-06-19	2024-12-06	-1.00	878,080	142,712		-	-	-	-	-	-	-	3,474	-	-	1,727	1,496	251	-
63	2023	Gas Construction Operations Enablement	Software(Intangible)	Gas	The project will implement an electronic work management solution that will enable Gas Construction Operations employees to assign, manage, and complete field work orders, eliminating the manual processes used. The work management system will also enable improved real-time tracking and reporting. The Gas Construction Operations department has operated on a paper process for work order completion since their initiation. Originally the work group was to be a temporary workforce, however ongoing improvements for the gas network have extended the need for the department. The current paper process creates additional work to produce and distribute to field operations. Also, the return of the completed paper process has a risk of human errors, lost paperwork, data lags, and readability. These manual processes often require additional contacts to field leaders and Field employees to post-verify information. This project will allow the electronic system to automatically process master orders in SAP, improving accuracy for Customers. The project will add value by: (1) improving visibility to work location of crews and job status updates in real time, (2) standardizing employee time-sheet management, (3) reducing closeout time by reducing data entry, (4) eliminating efforts to hand off paper copies of meter work orders, (5) reducing billing processing lag time for customers through direct updates to electronic forms, and (6) improving customer satisfaction with more timely meter installations dates. The scope of the project includes: (1) implementing an electronic work management solution for Gas Construction Operations, (2) enabling Gas Construction employees to assign, manage, and complete field work orders, and (3) developing the interfaces for management of the Gas Construction business unit. Alternatives considered include: (1) continuing with the existing paper process, and (2) SAP direct forms order entry and completion. These two alternatives were not chosen because manual workarounds will not improve safety or reduce job and administrative time, and SAP does not support entry of information without cellular connectivity. In addition, with direct SAP, a method of work assignment would need to be developed. The electronic work management solution was chosen because it will improve safety and reduce job and administrative time, while supporting information entry without cellular connectivity. This solution is a Company standard which simplifies the implementation and keeps ongoing maintenance costs down.	2021-01-25	2023-01-30	-0.40	1,856,304	151,939		3,138	-	-	-	-	-	-	3,192	-	-	-	-	-	-
64	2023	Gas Distribution Project Wise	Software(Intangible)	Gas	Project Wise is a suite of project collaboration software for engineering projects currently in use as the Company's gas transmission and generation engineering teams. It is capable of bundling, managing and handling the versions of records and documents related to designs, proposals, contract resources and record keeping. The Gas Distribution Project Wise project will expand the implementation of the software to gas distribution and be used to facilitate a management of change process for gas engineering design and gas system configuration changes. SharePoint and a centralized Company data store are currently used as a data warehouse for gas distribution engineering design documentation. The current solution has limited ability to meet the functional requirements for managing and approving the files and drawings that are unique to engineering design work. Gaps include: (1) inability to track design edits and document design change authorization approval; (2) inability to manage multiple outage windows and potential impact of planned projects; (3) inability to track gas system configuration changes, both temporary and permanent; (4) no current standards and structure of project documents for ease of view/upload/tag; and (5) no current dashboard for tracking as-built/final record completion. In addition, the engineering teams lack an effective tool to centralize the management of change processes for gas engineering design and gas system configuration, leading to unapproved changes to projects without proper knowledge and authorization. Without the proper controls and versioning in place, the opportunity for rework is enhanced causing extended project time for completion, negative impacts on other projects and increased costs. Completion of this project will provide value to the Company through: (1) comprehensive documentation of all design review changes from key technical Subject Matter Expert (SME) groups, ensuring that the final design is inclusive of all approved changes; (2) end to end workflow tracking and approval sign-off from initial design and engineering through field operations and final sign-off, providing for a controlled historical record that is traceable and verifiable; (3) consistent gas technical records across project and asset lifecycle; (4) increased public and employee safety and regulatory compliance with complete and accurate records that are easily accessible and easily searchable; (5) providing visibility to and improving tracking for system outage windows and to limit temporary pressure changes/reductions providing the ability to align outage schedules with distribution construction schedules; (6) tracking temporary and permanent gas distribution system configuration changes in a controlled repository; (7) maintaining spatial relationships with the drawings and documents such that all documents pertinent to a geographic location can be quickly accessed and retrieved; (8) providing a universal system of record for complete operating procedures; (9) creating a universal system of record for all construction prints; (10) centralizing tracking of Supervisory Control and Data Acquisition (SCADA) commissioning and decommissioning activities; (11) tracking project as-built and final project record completion; and (12) providing a centralized repository for document retention, archival and version tracking, resulting in records that are traceable and retrievable. Collectively, these items support the Company's implementation of the American Petroleum Institute (API) Recommended Practice 1173 Pipeline Safety and adherence to regulatory requirements. The project provides additional value by implementing a management of change tool with capabilities that can be replicated in other organizations, including gas engineering, metering and regulation, gas system integrity, and gas transmission. The scope of this project encompasses implementation in SAP of Project Wise software modules for use by Gas Distribution Engineering. The project will: (1) configure the software modules within the application, and (2) design and develop integrations with other Company systems. Alternatives considered include: (1) Continue with current SharePoint and shared data store warehousing solution for version report Gas Engineering designs and gas system outage windows. This alternative was not selected because it does not resolve the identified problems. (2) Develop and implement an in-house solution. This alternative was not selected due to cost and lack of expertise in developing a custom solution. (3) Implement Project Wise software. This alternative was selected for the following reasons: (1) Project Wise is available in a Software as a Service (SaaS) solution with out of the box capabilities, and (2) Project Wise aligns with the Company direction as it has been implemented and in use in other areas of the Company including Generation and Gas Transmission.	2022-02-28	2025-01-31	-1.00	861,663	239,185		699,197	-	-	-	90,668	540,638	24,215	43,690	36,351	-	-	9,306	24,996	2,049	-
65	2023	Gas Leak Asset and Work Management	Software(Intangible)	Gas	The project will implement functionality to automate gas leak compliance tasks and track all gas leak activity in the Gas Geographic Information System (GIS), creating a single system of record for gas leaks data, and providing a spatial display of leak data to improve leak management visibility. The gas leak process utilizes two systems to complete work and monitor gas leak compliance: SAP and Inspection Manager. Gas leak information is manually transferred between SAP and Inspection Manager and vice versa by compliance technicians. An internal audit identified 18 181 leak orders, resulting in a 6% defect rate, with inconsistent information recorded between SAP and Inspection Manager. Lack of quality control to help ensure accurate leak information across systems may inhibit management's ability to effectively monitor gas leaks and could result in leaks not being re-classified or repaired in a timely manner. This has regulatory compliance and safety impacts such as missed compliance dates which may result in fines and increased public safety risk resulting from untimely or missed leak repairs. The project provides value to both the Company and its customers, including: (1) improving productivity and leak location accuracy; (2) enabling near-real-time reporting and automated metric reporting to open leak backlog; (3) creating one system of record for all leak assets in GIS; (4) implementing quality improvements for scheduling and routing of leak crews; (5) reducing risk of future audit findings or non-compliance resulting from duplicate open leak orders; (6) optimizing resource allocation for gas service postingsteps by eliminating manual posting of leak repairs in GIS; (7) optimizing resource allocation for the gas compliance team by eliminating the posting of leak repairs in Inspection Manager; and (8) streamlining the leaks survey workflow to improve the human struggle cause id by use of paper maps and manual processes for leak order tracking. The scope of this project includes: (1) design and implementation of an integration between the asset system and the work management system to create, update, and manage leak maintenance, repair, and emergent orders and inspection schedules through the Enterprise Service Bus (ESB) or similar; Five alternatives were considered for the project: (1) Implement a Quality Assurance/Quality Control (QA/QC) process to ensure data is consistent between both SAP and Inspection Manager. This alternative was not selected because it requires an increase in labor costs for manual reporting and data checks. In addition, as demonstrated by the audit, manual processes, even manual QA/QC processes, are subject to human error, and each error creates safety and noncompliance risk. (2) Implement a Robotic Process Automation (RPA) to sync data. This solution was explored but is not viable because the business processes are too complex. (3) Implement a new GIS based compliance solution that can be integrated with SAP. This alternative is too costly, given recent investment in the current Inspection Manager solution. (4) Defer project implementation. The alternative selected is to implement this project now, rather than later, as a result of recent gas leak red audit findings. (5) Implement functionality to automate gas leak compliance tasks and track all gas leak activity in the GIS. This alternative was selected because it leverages existing solutions in a new way, optimizing resources and technology investment. The use of Cloud technology was not considered due to the enhanced functionality being added to systems and applications that are already on-premise.	2023-08-24	2024-12-27	-1.00	50,000	6,225		-	-	-	-	-	-	-	2,797	-	-	2,511	121	166	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHB-5)
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Witness: SHBaker
Date: December 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	RERC CATEGORY	BUSINESS CATEGORY/ P RODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAP ITALIZ ED EXPENDITURES FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION OF O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
66	2023	Gas Measurement, Regulation, Pipeline, and Storage (MRPS) Field Work Management Software (Intangible)	Gas		The project will move gas MRPS work orders from the current paper process to an electronic solution that includes work management, compliance scheduling and tracking, mobile dispatch and work completion functions. The current field processes and activities within Transmission Operations are hindered by lack of technology. MRPS does not currently have a technology solution for work order processing, parts ordering, dispatch and scheduling, GPS routing, and access to Company applications. As a result, employees rely on manual paperwork processes, handoffs, and work order management. The current field device could be better utilized if not for technology limitations that hindering customer benefits and employee engagement. The project will add value by: (1) increasing efficiency of order entry and management reporting through a digital solution rather than paperwork handoffs; (2) maintaining key compliance records without depending on paper processes and records; (3) improving productivity by eliminating the duplication waste of managing asset and compliance records management using paper binders; (4) reducing risk of MPSC non-compliance by digitizing systems data, making it readily available for review and analysis by leadership; (5) increasing ability to assist field using data available from a digital system to enable reporting and analysis; and (6) improving Safety by reducing risks to gas storage assets and adherence to standards by moving to digital systems and data. This enables future Safety initiatives such as a monthly well monitoring program that ensures accurate and timely data capture for identification and mitigation of areas at risk, analysis, and data trending. The project scope includes: (1) SAP updates to enable gas MRPS work processes; (2) prioritization methodology to evaluate and convert paper forms (upto 75 for compliance work, up to 75 for work order completion); (3) alignment of use with the compliance schedule and tracking solution on routing and documenting work, tracking time, and work order costing; and (4) development of Training materials and train-the-trainer activities. Alternatives considered include: (1) utilize an SAP module to migrate field work orders to an electronic platform; (2) implement a new solution - Field Manager Solution, Go Canvas, ESRI, and Smart Sheet were evaluated; (3) continue manual paper-based process currently used by the gas planning work force; and (4) implement a Service Suite solution. The first alternative was not selected because it did not offer a scheduling solution or support information entry in offline setting, location and time tracking required added integration, and a method of assignment and dispatch would need to be developed. The second alternative was not selected because the ad hoc applications that were evaluated were significant deviations from the field work management standard solution, reducing field crew usability through lack of integration and user adoption while increasing support complexity and cost. The third alternative was not selected because it does not eliminate the current process waste, rework, and human error risk. The alternative to implement the Service Suite solution was selected because it is the current field work management standard, providing work management scheduling capabilities, real time validation of field work order forms, and proven field crew adoption and usability resulting from four years of Service Suite usage by 3000+ Company field crews.	2020-12-28	2022-12-26	-0.92	2,635,822	11,646		878	-	-	-	-	-	873	-	-	-	-	-	-
67	2023	Gas SCADA Software Solution	Software (Intangible)	Gas	The Gas Supervisory Control And Data Acquisition (SCADA) software solution project will replace the current Gas SCADA Software with a more standardized software package enabling the Company to more efficiently meet Federal and MPSC requirements. The current Gas SCADA software solution was originally implemented in 2000 and was based on its gas system requirements at that time. While the solution has been maintained since its implementation, the Company's gas system has outgrown the current capabilities. As the solution ages, there is increased effort required to address obsolete application and database software architecture, and enhancements to the system are limited. To address the capability gaps, custom interfaces and integrations have been developed where each requires maintenance and support. This environment adds complexity and cost to solution upgrades and troubleshooting issues. The current Gas SCADA solution will limit the ability to invest in digital solutions for increased system health monitoring and preventative maintenance capabilities due to the complexity to integrate these future capabilities with it. The project will add value by: (1) reducing its IoT non-compliance by improving the ability to document and follow State and Federal requirements, improving customer safety; (2) improving efficiency and reliability when performing routine activities are upgrades, because standards out of the box software has less risk of breaking during upgrades, as opposed to more custom coded software; (3) reducing maintenance costs due to fewer individual software programs and less custom code; (4) improving Gas Control management capabilities that support the Federal and MPSC requirements for gas pipeline and Gas Control's ability to operate and monitor gas system operations; (5) improving reliability by using proven gas industry standard and software with configuration features, rather than a fully custom and system that has the possibility of being impacted by the next version update; (6) purchasing standard, out-of-the-box software that meets a high percentage of requirements and avoids multiple custom applications and specially coded programs to achieve results; (7) improving Natural Gas Delivery Plan efficiencies; and (8) providing a basis for capturing data required for use in computer-based preventative maintenance programs and more predictive technologies. In addition, implementing industry-specific software helps the collective gas industry users to encourage the vendor development of future version enhancements, which adds more value to the gas industry users. The comprehensive Gas SCADA system is used to monitor and control the operating conditions of the transmission and distribution gas system. The Gas SCADA system includes remote terminal units (RTUs), field devices (i.e. valves, meters, odorizers), and computers running SCADA software. This scope covers the Gas SCADA software solution only. The project scope includes the following: (1) significant planning, including consulting assistance, to define the implementation strategy for the effort, given the magnitude of the technology effort; (2) selection and implementation of a new Gas SCADA software solution; (3) planning of a phased roll out of new hardware and software; and (4) retirement and decommissioning of the legacy gas SCADA solution and equipment once the new system is fully tested and operational. Alternatives considered include: (1) continue to maintain the current solution, at the risk of increasing reliability issues that result in controlling and monitoring the Company's gas system; (2) invest in enhancing the existing Gas SCADA software solution which would introduce additional custom development and more specialized functionality that may not be supported in future vendor releases; and (3) replace the solution with a gas SCADA software solution that meets requirements to support the Natural Gas Delivery Plan. Alternative three has been selected to ensure sustainability for this critical solution. The current legacy system is operating at well beyond its original design specifications, so the potential points of failure are not fully known or understood. If the SCADA project is not completed, the legacy system could become unstable and impact Gas Control's ability to operate and monitor real-time system conditions, maintain safe operations, and compliance with regulatory requirements. It could also impact the ability to commission new facilities with require remote monitoring or control or cause the need for 24/7 manual field monitoring of certain facilities.	2022-04-18	2025-12-31	-0.96	18,016,040	2,305,237		1,949,568	708,742	966,193	53,782	219,056	4,241	17,212	161,360	-	-	149,361	1,788	10,211	-
68	2023	Gas Storage Probabilistic Risk Model	Software (Intangible)	Gas	The Gas Storage Probabilistic Risk Model project will implement a risk analysis model for comprehensive predictive risk analysis and modeling on gas storage wells. The current Gas Storage model is a relative risk model that equates risk to dollars from input information using qualitative data and risk scales to produce a risk ranking. In simple terms, the relative risk model is not capable of creating a statistically significant result. The risk assessment used in the current model provides a ranking for likelihood, consequence, and risk that is extremely only in comparison to other rankings. While the outputs provide a sense of relative risk when comparing one well to another, the ranks do not provide anything qualitative that relates to the failure of wells. Also, the current transmission model does not meet the requirements of the MPSC, as indicated in a letter of noncompliance (dated January 15, 2019), and rule making for storage systems has historically followed transmission rule-making. Lastly, the current model introduces risk in PHMSA findings as a non-probabilistic model. Completion of this project will provide value to both the Company and its customers. Each party will benefit from safety improvements and risk mitigation through statistically-based risk modeling that leads to more informed well improvement projects and improved targeted plug and abandonment projects. Implementing probabilistic risk modeling supports the changes planned for in the Company's Natural Gas Delivery Plan (NGDP), including the Company Gas Management Safety System (GSMS). GSMS incorporates the Company's plan to implement the American Petroleum Institute (API) Recommended Practice 1173 (Pipeline Safety Management Systems). Additionally, the implementation of a probabilistic risk model will: (1) calculate quantitative risk scores that include measures of probability, frequency, or expected loss of events, and (2) configure multiple data sources, to make advanced statistical calculations for interacting threats, both of which allow the Company to make more informed financial and strategic decisions based on risk. The probabilistic risk model will rank the wells in risk associated data by making it easier to interpret risk results for the purpose of making business decisions. Furthermore, the Pipeline and Hazardous Material Safety Administration (PHMSA) has identified the probabilistic risk model as a potential best practice for storage operators over other risk models (PHMSA Pipeline Risk Modeling white paper, dated May 9, 2018), so the project adds value by aligning with industry best practices. The project scope encompasses the implementation of a probabilistic risk model for gas storage wells. The project will: (1) install and configure risk model; (2) configure multiple data sources; and (3) develop reports and dashboards. Alternatives considered include: (1) continue the use of the relative risk model, but invest in substantial effort to continually manually managing data inputs and quality checks; (2) implement a custom, Excel-based probabilistic risk model through a consulting effort; (3) implement an on-premise probabilistic risk model, and (4) implement a cloud-based model. The first alternative was not selected because although the manual effort is possible, it is becoming increasingly difficult to complete as the model utilizes more data sources that need to be annually updated and validated. The second alternative was not selected because although the effort minimizes the IT cost of the project, the model requires the creation of a secondary data sources, leading to multiple "sources of truth". The on-premise solution is analyzed are not mature and have not been widely tested with transmission operators. The third alternative was not selected because it is the most cost-effective long-term implementation approach, providing commercial, off-the-shelf capabilities, industry proven and upgradable technology, and ongoing vendor support.	2023-04-14	2024-12-24	-1.00	1,577,860	145,522		907,902	531,730	-	2,460	351,042	911	21,760	115,363	-	-	474	114,750	140	-
69	2023	Gas Transmission Probabilistic Risk Model	Software (Intangible)	Gas	The project will implement a risk analysis model for comprehensive predictive risk analysis and model region gas transmission pipeline assets. Pipeline risk models are unit-less measures of risk derived from input information using qualitative data and ordinal scales to produce risk index scoring. In simple terms, the relative risk models does not provide true statistical measures. The risk assessment used in the current risk model provides a sense for likelihood, consequence, and risk that is relevant only in comparison to other scores. While the outputs provide a sense of relative risk when comparing one pipeline with another, the scores do not provide quantitative scores for probability, frequency, or expected loss of events. Although pipeline operations commonly use relative risk models, the quality of the relative risk ranking relies on subject matter expert inputs, human inferences, and opinions. Furthermore, the current model does not meet the requirements of the MPSC, as indicated in a letter of noncompliance (dated January 15, 2019), citing gaps in the model with respect to known failure data and well-aged fabrication threats, inadequate depth of cover calculations, level of corrosion, and inability to provide statistical validation. Inability to mitigate these non-compliances will be at a probabilistic risk model or through significant manual workarounds will likely result in continued non-compliances. Completion of this project will provide value to both the Company and its customers. Each party will benefit from safety improvements and risk mitigation through statistically-based risk modeling that leads to more informed pipeline replacement or improvement projects. Implementing probabilistic risk modelling supports the changes planned for in the Company's Natural Gas Delivery Plan (NGDP), including the Company Gas Management Safety System (GSMS). GSMS incorporates the Company's plan to implement the American Petroleum Institute (API) Recommended Practice 1173 (Pipeline Safety Management Systems). Additionally, the implementation of a probabilistic risk model will: (1) calculate quantitative risk scores that include measures of probability, frequency, or expected loss of events; and (2) configure multiple data sources to make advanced statistical calculations for interacting threats, both of which allow the Company to make more informed decisions based on improved quality inputs in a measurable model; and (3) provide information for better decisions on Capital project improvements and integrity management. Unlike the current unit less relative model a probabilistic model will be a unit based risk score, specifically in the unit of dollars, improving efficiency in interpreting risk results for business decisions. The project scope encompasses the implementation of a probabilistic risk model for gas transmission. The project will: (1) install and configure risk model; (2) configure multiple data sources; and (3) develop reports and dashboards. Alternatives considered for the project include: (1) Continue the use of the relative risk model, but invest in a substantial effort to build customization to bring the model into compliance. This alternative was not selected because although custom workarounds can make the model into compliance, the work-arounds still result in arbitrary, relative rankings and do not provide confidence in the ability to provide statistical validation of results. (2) Implement a custom, Excel-based probabilistic risk model through a consulting effort. This alternative was not selected because although the effort minimizes the IT cost of the project, the model requires the creation of secondary data sources, leading to multiple sources of truth. (3) Implement an on-premise probabilistic risk model. This alternative was not selected because the on-premise solution is analyzed are not mature and have not been widely tested with transmission operators. The option of implementing the cloud-based probabilistic risk model was chosen because it is the most cost-effective long-term implementation approach, providing commercial, off-the-shelf capabilities, industry proven and upgradable technology, and ongoing vendor support.	2020-12-28	2024-07-29	-1.00	1,064,124	257,685		178,998	345,050	-	1,084	(211,835)	3,824	42,891	2,806	-	-	208	2,423	175	-
70	2023	Product Family Enhancements-Gas-Capital	Software (Intangible)	Gas	The Gas Engineering and Operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, new or revised regulations, customer feedback, and other improvement ideas. Enhancement requests require a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's value of software enhancements in Gas Engineering and Operations. The value of software enhancements in Gas Engineering and Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Gas Engineering and Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering and Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using a ranked benefits criteria. The annual enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project funds the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	309,283	-		309,283	-	-	82,176	185,930	12,782	28,395	-	-	-	-	-	-	-
71	2023	Product Family Enhancements-Gas-O&M	Software (Intangible)	Gas	The Gas Engineering and Operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Gas Engineering and Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Gas Engineering and Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering and Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using a ranked benefits criteria. The annual enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project funds the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	-	280,258		-	-	-	-	-	-	-	280,258	-	-	-	78,827	185,272	15,442	717
72	**SUBTOTAL**	**2023 Gas**										**4,534,730**	**1,591,941**	**993,835**	**330,178**	**1,222,730**	**69,493**	**326,353**	**652,410**	**213**	**5,695**	**369,386**	**348,287**	**30,804**	**1,064**
73	2023	800 MHz Modernization	Network	IT Digital Foundation	Project not allocated.							276	-	276	-	-	-	-	-	-	-	-	-	-	-
74	2023	ARP-Local Area Network	Network	IT Digital Foundation	This project will upgrade the Company's entire Local Area Network (LAN) and a significant portion of the Wireless Local Area Network (WLAN). At some Company locations, LAN equipment has been in service since 2011. If the LAN/WLAN hardware and software are not routinely refreshed, the Company will lose the manufacturer support needed for equipment bug fixes, security vulnerability patches, and enhancements. In addition aging equipment cannot accommodate the increasing demand for wireless devices necessary for performing-to-day operations that rely on wireless enabled devices, such as rugged field devices, cell phones, barcode scanners, tablets, and other mobile devices. As equipment ages, it is at risk of higher failure rates, which increases the risk of unplanned outages. In the event of unplanned outages, business services would not be able to access services in the corporate network including email, SAP, Internet, and phones. The project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor supported, thereby ensuring support for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; (6) increasing user productivity through a higher performing wireless network, which increases the productivity and efficiency of office and field employees serving customers; and (7) improving support for wireless Internet Protocol (IP) phones, Internet of Things (IoT) and field devices. The project scope includes: (1) refreshing the LAN equipment and wireless access at Company sites; (2) identifying the required features for the new equipment; (3) implementing the new equipment according to industry best practices; (4) replacing wireless networks with upgraded infrastructure and verifying wireless coverage is as expected; and (5) decommissioning old equipment. Alternatives considered include: (1) Replace the existing units with new units from other radio and modem manufacturers; (2) purchase new radio subscriber units from existing manufacturers, but invest in system-level work to ensure requires replacement of existing management systems with a new vendor specific and would need to duplicate effort if the Company were to move to different equipment. This would result in a significantly higher investment. Option 2 was selected as this has the least disruption to radio and mobile data system users and delivers the highest value and lowest cost solution to meet the objectives of this Business Case.	2023-01-01	2023-12-31	-1.00	4,845,746	113,699		2,138,252	124,497	1,776,877	115,910	73,215	7,926	29,757	39,795	-	303	12,718	25,492	1,281	-
75	2023	ARP-Radio	Network	IT Digital Foundation	This project will refresh hardware to include; 800MHz Radios, cellular modems, plant radios and systems, cellular amplification devices and vehicle consoles in service trucks. This equipment supports mission critical voice and data communications for plant and field service personnel and dispatch personnel. 800MHz radios and Plant radio systems are upgraded on a scheduled 7-year lifecycle basis. Cellular modems are refreshed on a 5-year life cycle basis. Amplification systems are refreshed on a 10-year life cycle. Vehicle consoles are typically retired with the vehicle but are salvaged for reuse in new vehicles when possible. 800MHz, mobile, and portable radios, Plant radio systems, and vehicle consoles are refreshed, the Company will lose the manufacturer support needed for equipment bug fixes, security vulnerability patches, and enhanced features; (5) providing consistent wireless coverage across Company locations; (6) increasing user productivity through a higher performing wireless network, which increases the productivity and efficiency of office and field employees serving customers; and (7) improving support for wireless Internet Protocol (IP) phones, Internet of Things (IoT) and field devices. The project scope includes: (1) refreshing the LMR equipment and wireless access at all Company sites; (2) identifying the required features for the new equipment; (3) implementing the new equipment according to industry best practices; (4) replacing wireless networks with upgraded infrastructure and verifying wireless coverage is as expected; and (5) decommissioning old equipment. Alternatives considered include: (1) Replace the existing units with new units from other radio and modem manufacturers; (2) purchase new radio subscriber units from existing manufacturers, but invest in system-level work to ensure requires replacement of existing management systems with a new vendor specific and would need to duplicate effort if the Company were to move to different equipment. This would result in a significantly higher investment. Option 2 was selected as this has the least disruption to radio and mobile data system users and delivers the highest value and lowest cost solution to meet the objectives of this Business Case.	2023-01-01	2023-12-31	-1.00	734,859	62,731		322,790	-	304,364	25,965	9,388	2,221	(18,203)	21,956	175	9,222	6,083	5,557	918	-
76	2023	ARP-Collaboration	New Computers / Hardware	IT Digital Foundation	This project will replace the Company's obsolete or out-of date audio, visual, telephony and other communication collaborative tools and equipment. When Collaboration Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value by: (1) ensuring that the Company's audio, visual, telephony, and other communications systems are stable and reliable; and (2) retiring the legacy enterprise Avaya telephone systems that have reached end of mainstream manufacturer support. The project scope consists of: (1) annually replacing aging collaboration assets; and (2) installing new collaboration assets to account for evolving business requirements. The following alternatives were considered: (1) refresh a portion of the audio assets; (2) refresh a portion of the audio assets only; and (3) refresh visual assets only. These alternatives were not chosen due to the risk inherent with a partial replacement of assets, which include: (1) a reduced supply of equivalent replacement Avaya parts that are no longer be produced; and (2) an erosion of the knowledge technicians possess on discontinued systems.	2023-01-01	2023-12-31	-1.00	1,839,809	146,132		593,211	893	515,310	12,925	36,117	1,784	2,081	51,146	-	6,997	12,276	30,377	1,496	-
77	2023	ARP-Core Network	New Computers / Hardware	IT Digital Foundation	This project will refresh the Data Center network equipment. When network assets that are used to support customer interactions and ensure the stability of mission critical business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project will create value by: (1) increasing network availability; (2) adding new functionality; (3) increasing network performance; and (4) standardizing network infrastructure across Data Centers. The project scope includes the replacement of all core network devices with next generation devices. The alternative considered was to continue running in the current state or delay the replacement of network devices and accept the risk of further business and customer impact when more equipment failures occur.	2023-01-01	2023-12-31	-1.00	26,320	-		8,446	-	-	6,050	-	3	2,391	-	-	-	-	-	-	-
78	2023	ARP-Field Device Asset Management (FDAM)	New Computers / Hardware	IT Digital Foundation	This project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failure, security patches, and software compatibility. When Field Device Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and can be very difficult to keep current with Security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular four-year refresh cycle. This project creates value for the Company: (1) improving stability and availability of business-critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing field workers to complete their jobs tasks. The project scope consists of replacing field device assets according to the four-year refresh cycle. The alternatives considered were to: (1) extend the replacement cycle from four years to five years for field devices; and (2) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the assets that need refreshing in future years based on the number of devices that were not replaced during the four year refresh cycle; and (4) it could cause an inability to apply security patches. Waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and harm its reputation. The Company selected a four-year refresh cycle to alleviate these concerns.	2023-01-01	2023-12-31	-1.00	3,273,840	2,491		1,030,148	-	1,004,596	4,597	-	-	1,056	872	-	-	551	321	-	-
79	2023	ARP-Operational Technology Support Gas	New Computers / Hardware	IT Digital Foundation	The As set Refresh Program (ARP) - Operational Technology (OT) Support Gas project will replace datal and o bsolete servers and storage infrastructure. When Operational Technology assets that are used to ensure the safety and reliability of technology that supports critical gas operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates and runs the risk of failure. If the Company does not adhere to a regular refresh cycle. The project creates value by maintaining the currency of the Company. The programs scope consists of: (1) the annual replacement of compute hardware under the program; and (2) installing additional new compute capacity to account for new kingdoms requirements. The alternatives considered include: (1) operate server and storage infrastructure beyond a five to seven-year refresh cycle or (2) refresh server and storage infrastructure based on a five to seven-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five to seven-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety issues for customers, as most vendors do not provide extended support after seven years. The Company chose the alternative to refresh this server and storage infrastructure based on a five to seven-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacts to critical infrastructure that supports systems such as Gas SCADA and Gas Compression control systems.	2023-01-01	2023-12-31	-1.00	244,997	16,579		246,997	187,593	46,009	6,108	2,998	599	1,703	16,579	10,496	-	2,909	2,736	438	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	RERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
80	2023	ARP-Printer Asset Management (PAM)	New Computers / Hardware	IT Digital Foundation	This project will replace and install select printers, plotters, and multi-function printing devices based on printer replacement assessments and a five year refresh cycle. Printer service and usage history is evaluated and a determination is made if a printer can be repurposed instead of ordering a new one. When Printer Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and more difficult to keep current with firmware and security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improving the dependability of these printer devices for employees; (2) exerting increased costs due to hardware repairs; and (3) ensuring compatibility with enterprise print applications. The project's scope consists of the annual replacement of printer assets according to a five-year refresh cycle. The alternatives considered for the project included looking at refresh cycles from three to seven years as well as running the assets to failure. The selection of a five-year cycle was deemed to be the best solution since anything less than five years would increase the likelihood of unneeded expense for replacement of assets that were still in good operating condition. Anything greater than five years is assessed monthly to ensure it is not run to failure, including running the asset to failure, resulting in additional expense for maintenance of the equipment and downtime, negatively affecting employee productivity. The Company has optimized printer needs based on the shift to a hybrid work model during and after the pandemic. The Company anticipates an increase in co-workers returning to in-person work in 2023, resulting in a need to refresh printers that are at risk of failure.	2023-01-01	2023-12-31	-1.00	332,691	19,064		119,737	-	107,264	4,146	-	(5,569)	897	6,672	-	-	5,972	260	440	-
81	2023	ARP-Server	New Computers / Hardware	IT Digital Foundation	Prior period adjustment.							(15,930)	(13,749)	(2,181)					17,806	15,000	2,380	426	-	-	-
82	2023	ARP-Server and Storage	New Computers / Hardware	IT Digital Foundation	The Asset Refresh Program (ARP)"Server and Storage will replace or augment server and storage infrastructure for the Company. When Server and Storage Hardware Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and can be very difficult to keep current with security updates. The Company also runs the risk of failure of these assets if impacting customer interactions and business operations if it does not adhere to a regular five to seven-year refresh cycle. This project creates value for the Company through: (1) improved stability and availability of business critical applications by proactively replacing server and storage hardware assets prior to the likelihood of increasing hardware failures; and (2) ensuring that adequate resources are available to support application demands after five to seven years of actual use. The scope of this program encompasses: (1) replacement of server and storage hardware assets; and (2) installation of additional new computers and storage capacity to accounts for evolving business requirements. The alternatives considered were to purchase extended maintenance, move some of these assets to the cloud with the Digital Hybrid Cloud and Data Center Migration project, or to replace the assets in the current cycle. The option to purchase extended maintenance was not selected because full support would not be offered after seven years and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital Hybrid Cloud and Data Center Migration project while refreshing the remainder up to the five-to-seven-year cycle as it is the most cost effective option. If the Digital Hybrid Cloud and Data Center Migration project is not approved as part of this rate case, the Company plans to continue to refresh these critical technologies at the current level based on a five- to seven-year refresh cycle to mitigate the risk of failure.	2023-01-01	2023-12-31	-1.00	2,267,206	273,289		727,510	-	274,339	199,301	39,215	31,510	(28,414)	11,179	99,651	-	5,582	13,666	52,119	20,553	-	3,932	-
83	2023	ARP-Workstation Asset Management (WAM)	New Computers / Hardware	IT Digital Foundation	This project will replace and install new desktops, laptops, and tablets on a four year refresh cycle based on industry standards, hardware failures, security patches, and software compatibility. Monitors will be replaced every eight years based on Company data related to its typical failure rates. When Workstation Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and can be very difficult to keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improving stability and availability of business critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing business partners to complete their job tasks. The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources. The alternatives considered were to: (1) extend the replacement cycle from four years to five years for all desktops and laptops; (2) extend the replacement cycle only on desktops from four years to five years; and (3) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the ARP in future years based on the number of devices that were not replaced during the four year refresh cycle; and (4) it could cause an inability to apply security patches. Waiting longer than the four-year cycle would increase hardware failures, security patch issues, and hardware compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle for desktops, laptops, and tablets, and an eight-year cycle for monitors to alleviate these concerns.	2023-01-01	2023-12-31	-1.00	6,152,454	119,140		1,973,707	-	1,873,153	76,753	-	5,477	18,123	41,699	-	2,770	4,186	21,114	1,654	11,975	
84	2023	Digital-Hybrid Cloud and Data Center Migration	New Computers / Hardware	IT Digital Foundation	This project will optimize data center assets and asset replacement project purchases by migrating or retiring applications out of existing Company and co-location data centers into cloud services, reducing operational costs for running IT services and leveraging increased cloud capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services. The technology currently deployed in the Company's data centers meets many customers' needs today. However, the pace of digital transformation is increasing rapidly, and requirements for applications are evolving faster than the technology in the Company's data centers can respond in a cost-effective manner. This data center constraints lead to longer implementation times, missing capabilities, or reduced functionality in the applications that the Company can deploy. This project will create value by ensuring the Company's technology requirements are met through a comprehensive and cost-effective combination of data centers and public cloud services. Specifically, by migrating applications to cloud services, the project will: (1) reduce capacity, hardware maintenance, and security device costs at the co-location data center; (2) reduce hardware maintenance and security device costs at the Parnall data center; (3) enable the ability to scale infrastructure quickly up or down without costly upfront hardware purchases; (4) reduce application risk through cost-effective, scalable infrastructure redundancy and availability; (5) reduce ongoing server and storage asset replacement costs; (6) reduce ongoing networking equipment replacement costs; (7) reduce managed service operational support costs; and (8) enable the use of a variety of cloud services to support Company applications. The project scope includes: (1) promoting the co-located Grand Rapids Main co-location data center to become the primary data center for on-premises IT services; (2) demolishing the Company's Parnall data center to the data center recovery data center for on-premises IT services; (3) analyzing applications for migration to cloud or retirement; (4) migrating applications from on-premises to cloud; (5) transforming applications to use cost-effective cloud services; (6) altering network architecture and deploying base infrastructure to allow each location (on-premises or in cloud) to function independently; (7) deploying cloud and on-premises cost management tooling and processes; (8) simplifying and optimizing backup and disaster recovery resources and processes using cloud services; (9) implementing additional automation for application deployment and management; (10) changing the operations model to support all cloud based applications; (11) educating and increasing the skillset of IT and other employees in leveraging public clouds services; and (12) transforming IT to become the broker of cloud services for the Company. Alternatives considered included: (1) migrating to public cloud services faster. This alternative was not chosen because the Company's ability to absorb new technologies coupled with the investments the Company has already made in data center equipment would prevent a faster move from being efficient and effective, introducing additional financial risk; (2) migrating to public cloud services slower or not at all. This alternative was not selected because delaying public cloud services and capabilities could limit requiring an extension of the life of existing data center equipment creates increased financial and operational risk; and (3) contracting with an outside vendor to provide cloud services for some applications for the Company. This alternative was not selected because industry information shows the option as not yet as cost effective or not providing a maturity level that the Company would be able to easily consume with limited in-house experience and expertise in public cloud. The alternative to migrate to a hybrid cloud and data center model was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.	2023-02-01	2025-12-30	0.12	6,876,180	5,887,409		898,507	419,429	121,481	73,234	226,838	19,633	20,956	185,091	-	-	50,182	124,139	10,648	122	
85	2023	Ransomware Recovery	New Computers / Hardware	IT Digital Foundation	This project will implement a multi-layered security approach to our production data center backups to mitigate data loss risk to ransomware attacks. A severe ransomware attack could leave the Company without access to critical data and unable to recover the data. In a best case scenario, a successful ransomware attack would likely result in prolonged system outages for up to a week and months of work to recover remaining systems. The project will add value to the Company and its customers by: (1) implementing a 3-2-1-1 (3 copies, 2 media, 1 offline, 1 immutable) strategy to protect the production data center data and backups. This strategy will protect the Company from production data center data to from a broader scope of cyber threats including ransomware. (2) Providing various restoration options to reduce data loss and improve recovery time. (3) Mitigating the risk of complete data loss with a maximum security backup store a weekly copy of production data center data offline and in a format that cannot be changed. (4) Defining a ransomware response plan that the Company can use to respond to a wide array of cyber attacks with a practiced process. (5) Providing the ability for OT to sever all communications to the public internet and protect the Company's OT network. The scope of this project is to deliver one cloud hardware storage level snapshots, local immutable copies of production and OT data center data, public cloud third copy of 100% of production data center data, and a ransomware recovery plan with a scenario-based approach to ransomware response including plans for monitoring, containment, malware clean up and recovery. The project team looked at a number of alternatives to provide a ransomware recovery plan including paying the ransom, using tape backup, restoring to the public cloud, and buying a third datacenter. The project team looked closely at tape backup but with Company's heavy investment in their current solution for backup and the ability of the current solution to provide immutable copies the team felt that the current solution's scalability better met the requirements and at a lower cost and faster delivery. Restorations to the public cloud was also considered, but the recovery would have been extremely complex and likely would have taken 3-5 years to get in place. Lastly the project team looked at setting up a third data center that would be used as an offline copy of production. The cost was too high and it didn't provide any value over our current public cloud and on-premises backup copies of production and OT data center data.	2021-01-04	2024-09-30	-1.00	3,178	888		1,039	-	-	576	-	57	386	311	-	-	289	-	22	-	
86	2023	SAP HANA Database Migration	New Computers / Hardware	IT Digital Foundation	In preparation for SAP's planned end of support for its Business Suite product in 2027, the Company will migrate its existing SAP databases from Oracle to SAP HANA in advance of the required move to S/4 HANA. The Company's SAP applications currently utilize Oracle's relational database management system as their underlying database storage technology. SAP has informed its customers that standard support for its legacy Business Suite (ECC) product will end in 2027, along with support for all non-SAP database platforms. SAP has also informed customers that the future direction for their enterprise solution is S/4 HANA, a solution built explicitly for their HANA database platform. To prepare for these upcoming events, the company will migrate all of its SAP databases off of Oracle and onto SAP HANA. This project lays the groundwork for the company's eventual shift to SAP's HANA-based solutions by: (1) proactively migrating SAP databases to a database technology that is fully supported by SAP beyond 2027; and (2) mitigating the risk of a complete loss of support for the current Oracle database technology in 2027. Project scope includes: (1) procurement of HANA software licensing to cover all migrated SAP applications; (2) data migration for all SAP applications from the Oracle database to SAP HANA; and (3) implementation of new application support policies, procedures and tools required to manage the newly migrated SAP HANA applications. Given SAP's announcement regarding the end of support for its ECC product in 2027, all customers running SAP on database software other than HANA will also lose support for their associated database software in 2027. SAP is offering one option for databases other than HANA beyond 2027. While there is no alternative to the HANA database for SAP going forward, the Company has considered multiple options: (1) Perform a direct migration from SAP Business Suite on Oracle to S/4 HANA. A direct migration to S/4 HANA brings greater operational risk to the Company as both the underlying database technology and the SAP application functionality would change simultaneously, so this alternative was not selected. (2) Remain on the current SAP Business Suite product but competitively bid support services to a third-party provider instead of SAP. This alternative was not selected because moving to a third-party support model forces the Company to remain on outdated SAP software and eliminates any possibility of benefitting from new business functionality provided by S/4 HANA. It will also require the Company to accept significant risk due to the fact that SAP, as the product's technical owner, will not be available upon termination of the SAP maintenance agreement. (3) Migrate to SAP's Software as a Service (SaaS) implementation of S/4 HANA. This alternative was not selected because an S/4 HANA SaaS migration is a much more disruptive option as the Company's business processes would require adjustments to accommodate functionality differences between ECC and S/4 HANA. The risk of negative business impact is significantly greater than simply changing the underlying database technology. The selected alternative to migrate the SAP databases to HANA prior to implementing S/4 HANA gives the Company several years to solidify its HANA database infrastructure before into during the substantial business process changes required with S/4 HANA.	2023-04-24	2025-12-31	-0.72	6,491,044	1,352,658		767,217	713,092	-	12,654	33,056	3,087	5,330	63,293	11,318	-	21,714	27,079	3,182	-	
87	2023	2010 SharePoint Platform Replacement	Software(intangible)	IT Digital Foundation	Prior period adjustment.							-	-	-	-	-	-	-	153	4	-	-	-	-	149
88	2023	Application Currency-EPS-O&M	Software(intangible)	IT Digital Foundation	The EPS (formerly IACI) initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the EPS adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the EPS are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	-	84,880		-	-	-	-	-	-	-	32,588	-	-	17,284	13,198	2,106	-	
89	2023	Application Currency-IT/Digital Foundation-Application Platforms-O&M	Software(intangible)	IT/ Digital Foundation	The Application Platforms initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Application Platforms area are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	-	39,373		-	-	-	-	-	-	-	15,117	-	-	11,863	2,244	1,009	-	
90	2023	Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M	Software(intangible)	IT Digital Foundation	The Infrastructure Platforms initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Infrastructure Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Infrastructure Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	-	7,037		-	-	-	-	-	-	-	2,639	2,617	-	-	22	-	-	
91	2023	Cloud Virtual Desktop	Software(intangible)	IT Digital Foundation	Prior period adjustment.							-	-	-	-	-	-	-	(60,166)	(68,027)	-	7,383	-	476	-
92	2023	Digital-Cloud Data and Analytics Platform	Software(intangible)	IT Digital Foundation	This project is a data-led transformation that will accelerate and scale Artificial Intelligence (AI) and analytics in the cloud across the business to uncover new paths to value, faster, allowing the organization to make better decisions and enable delivery outcomes for the Natural Gas Delivery Plan, Electric Grid Integration, customer programs, and other business needs. The project will additionally establish data governance roles and responsibilities, processes, and implement tools to support best practices across the enterprise. Consumers Energy faces several challenges in the ongoing data modernization journey, which include: (1) legacy data platform operations; (2) high lead times for data exploration and identification of data assets; (3) lack of data ownership and quality; (4) limited data governance best practices across data ownership, access control & security; and (5) new development environment for business intelligence report and analytics. Despite the growing importance of data and analytics in business decision-making, Consumers Energy struggles to modernize and transform data and analytics platforms because multiple business units are working in silos. The siloed approach to data and analytics that is preventing organizations from taking advantage of economies of scale and achieving a positive return on investment (ROI). Each business unit operates independently with its own data projects, leading to duplication of effort, increased costs, and missed opportunities for collaboration. The lack of coordination and integration across business units also makes it challenging to develop a comprehensive understanding of the organization's data, resulting in missed opportunities for insights and strategic decision-making. As a result, the organization is unable to realize the full potential of their data and analytics investments, which can limit their ability to compete effectively in today's fast-paced business environment. To address this problem, it is essential to break down silos and establish a unified data and analytics platform that leverages economies of scale to generate value across the organization. The project will add value by accelerating the data modernization journey to cater for evolving business needs by: (1) optimizing data platform operations costs with workflow based platform infrastructure deployment using prebuilt terraform modules and templates; (2) reducing data operations build complexity and data engineering cost through automation; (3) improving data quality, lineage, tools and ownership through data governance that leads to reduce cost of data provisioning, data duplication, and improved data veracity; (4) streamlining data access requests, management, and governance to reduce risks and support efficiency; and (5) increasing the speed to deliver new data and data capabilities, improved productivity, and reduced lead time for data consumers through data democratization. The project scope includes: (1) developing and modernizing the analytics platform in the Azure cloud to allow Consumers Energy teams to implement new use cases leveraging simplified infrastructure configuration and automated deployment processes; (2) build and deployment of a data management capabilities, controls, cataloging, assets, and data lineage; (3) developing data ordering workflows and data access management controls; (4) continual prioritization and onboarding new datasets; (5) simplifying infrastructure configurations; (6) automating deployment processes; (7) enabling data governance tool and processes. Alternatives considered include: (1) Address current pain points in existing on-premise analytics platform. This alternative was not selected because the existing platform requires new investment in licensing and infrastructure, delivery for new capabilities cannot keep pace with demand, and still requires investment to address accruing legacy system technical debt. (2)Continue to build analytics in the cloud based on the current foundation. This alternative was not selected given learnings gained from two projects where lack of maturity on the current platform created significant delays in delivery. Additionally, this alternative limits the Company's ability to have required data and analytics capabilities to solve business goals or reducing the cost to deliver new capabilities. (3) An alternate data platform and governance modernization that leverages new data and analytics platform in the cloud. This alternative was selected because it provides the best speed to delivery for analytics capabilities, provides faster access to data that is critical to optimizing business process and achieving business goals, provides a path to more rapidly resolving technical debt, and reduces delivery costs for future analytics projects.	2023-04-17	2024-12-27	-1.00	12,263,186	1,683,500		1,072,128	207,967	-	206,205	579,737	19,784	58,430	69,087	-	-	28,966	36,740	3,381	-	
93	2023	Digital-Data and Analytics in the Cloud	IT/ Digital Foundation	IT/ Digital Foundation	This project will extend the Company's current data and analytics environment into a cloud environment, which will enable data and analytics at-scale and enable the delivery of outcomes for the Natural Gas Delivery Plan, Electric Grid Integration, customer programs, and other business needs. The Company currently has an on-premise data and analytics platform, Data Lake, that houses multiple data attributes ranging from customer, grid, and operations. As the Company requires more predictive and prescriptive analytical use case outcomes, the current environment is insufficient to handle the data analytics at-scale for multiple use cases. Also, the current solution lacks the libraries of advanced ML, AI tools, and industry-Standard Big Data Ingestion tools, which are standard offerings as part of Cloud environments, such as Amazon Web Services (AWS), Azure or Google Cloud Platforms. The project will add value by: (1) providing the ability to perform data analytics at-scale; (2) allowing the ability to leverage the leading ML and AI tool to enable predictive and prescriptive analytics at-scale; (3) providing the ability to provision infrastructure at-scale rapidly, Vulnerability pay for use; and (5) empowering faster prototyping, testing, and deployment of analytics solutions. For example a ML model is used to predict Estimated Time for Restoration (ETR). This model needs to be trained with a large amount of data about past outages. Procuring the compute on-premise for just this one use-case does not make sense from the project and need new skills to support and a separate maintenance cost and agreement because the IDPU hardware is different from the rest of our existing compute. The process is much simpler and faster if we setup our analytics platforms on the cloud. The project scope includes: (1) the execution of data analytics without scalability constraints; (2) flexible transition with technology platforms as they evolve; (3) the use of out-of-the-box ML and AI tools provided by cloud vendors; (4) new services and innovations in the cloud platform; (5) capacity pay per use; and (6) the foundation for future cloud migration and maintenance. The alternative considered to a cloud solution is to expand the on-premise infrastructure and purchase multiple tools to solve individual capability gaps. The Company did not choose this alternative because it is more costly than cloud due to higher infrastructure costs and a larger workforce required for implementation.	2022-06-20	2023-11-27	-1.00	501,545	168,524		180,896	4,559	-	42,071	86,566	4,832	22,868	43,764	207	-	31,228	9,330	2,999	-	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025, and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHS-5)
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Witness: SHBaker
Date: December 2024

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	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAP IT ALS P END FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD GAS	NON-LABOR OTHER GAS	GAS PORTION OBLM SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER GAS
94	2023	Enhancements -Cloud Automation	Software(intangible)	IT/Digital Foundation	The Enhancements - Cloud Automation project provides funding for small changes and improvements to existing software to address requests needed due to changing business requirements. The Company's existing cloud automation platform consists of a number of scripts that automate the build of infrastructure such as servers, operating systems, databases, and application installations in minutes or hours. These scripts include security hardening and application of the latest patches. This project will maintain and improve these scripts to ensure they meet the latest security policy requirements, and any changes to the way the operating systems, databases, or applications are configured. The value of this enhancement project is the implementation of small changes and functionality improvements to existing IT software application investments for Cloud Automation to make hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigat ng risk. The scope of the enhancement includes requests that will be fulfilled to provide functionality for areas such as IT infrastructure provisioning. The alternative would be to continue as is with existing scripts; however, this introduces security risks and additional manual steps to build infrastructure, which in turn, will lead to increased costs and risk of manual errors.	2023-01-01	2023-12-31	-1.00	314,721	130,501		110,198	-	52,452	51,666	(41,948)	5,536	33,257	66,675	-	-	8,529	57,376	771	-
95	2023	Enhancements -IT-Capital	Software(intangible)	I T Digital Foundation	The I T initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	168,145	75		59,941	730	-	14,284	18,388	1,677	18,862	26	-	-	17	-	-	8
96	2023	Enhancements -IT-O&M	Software(intangible)	I T Digital Foundation	The I T initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	-	73,027		-	-	-	-	-	-	-	28,038	1,687	-	3,512	21,703	1,137	-
97	2023	Enterprise Service Bus Application 2020-2021 Upgrade	Software(intangible)	I T Digital Foundation	This project will upgrade and migrate the Business Works developer application to the next version. Newer Enterprise Service Bus (ESB) software versions offer improved integration with cloud-based services and applications. As the Company increasingly migrates to cloud-based infrastructure, Platform- and Software-as-a-Service solutions, it is critical that it has the vital data tool or pathway, be more scalable, secure, and capable of working in a cloud-based environment. In addition, the messaging and event modules within the ESB are currently outside of their standard support windows. While IT sees ble to continue to get extended support by paying an estimated premium of $45,000, this is just temporary coverage and serves only to delay the need for an upgrade. The value in this project provides the Company the capabilities to: (1) accelerated productivity; (2) continuous delivery and integration; (3) an open ecosystem for improved operational visibility; (4) real-time integration with web, mobile apps, and application programming interfaces; and (5) improved administrative and operational efficiencies. The project scope includes: (1) implementing new versions of all applications that are part of the TIBco ESB software suite ™ TIBnimeWeb 4x, Enterprise Messaging Service, Business Events, API Exchange, and Hawk; and (2) a server refresh. The new products will be implemented on the latest version of the SUSE Enterprise Edition operating system. Alternatives considered included: (1) Absorb the annual $40,000 maintenance cost and live as supportability. Given the critical nature of this application, it is not recommended to lose mainstream support for any of the applications involved. Any sustained ESB product deficiency would impact many areas of the Company, such as billing, revenue collection, and remote meters. The current implementation of the ESB platform was built with 5 years of growth in mind. This alternative is not chosen for these reasons, and the additional expense. (2) Replace the platform by moving this to cloud. Migrating the ESB to the cloud would be too risky in the Company's strategy for cloud adoption, which may cause issues with operational stability and incur additional expenditure. A cloud migration would also take longer to plan, which would put the Company at risk of falling outside of the current vendor support window for its product's current version. (3) Upgrade the existing application. This option was selected because it best suits customer and Company needs for the near future by restoring vendor support for hot fixes and patches, and enables product scalability to the measure required of the business.	2020-10-26	2024-08-29	-0.97	5,423,110	1,670,313		498,961	287	-	145,377	210,658	24,457	114,186	365,358	-	58,333	104,964	183,305	18,590	166
98	2023	I T Operations Management - Service Operations	Software(intangible)	I T Digital Foundation	This project will implement an application service mapping tool to effectively manage business-critical services through identification of infrastructure components and application interactions. This tool automates the mapping process to create a complete, up-to-date, and accurate record of the mapped application service in the Database. Application service mapping works hand-in-hand with asset discovery, building on discovered infrastructure data to identify all the assets that support a service, and along with their service specific relationships. As the IT systems steadily increase in complexity and evolve faster than the IT organization can respond to system issues in an optimized and cost-effective manner, the current configuration of the system does not provide the clarity needed in order to understand how the infrastructure interacts with the applications within the IT business. It supports and in order to respond to emergent IT incidents in the most rapid and cost-effective manner. These constraints can lead to lengthy response and implementation times; negligible or ineffective resolutions; reduced functionality; and elevated outage times in the infrastructure and applications in the system. This project will create value for the Company by mapping critical applications through discovery of the underlying infrastructure associated with application services and its relationship to parent business applications. Specifically, by creating application service maps, this project will: (1) increase visibility and understanding between Information Technology (IT) infrastructure and Configuration Items; (2) improve accuracy through real-time, automatically updated infrastructure and component changes; (3) reduce IT Subject Matter Experts time on emergent IT issues; (4) Utilize of IT Service Management processes; and (5) Reduce downtime by identifying dependencies and impact analysis. The project scope includes: (1) implementation of On-Premise application service maps which have significant business impact; (2) establishment of process roles needed to support service maps built. Alternatives considered included: (1) Choose an alternate IT Operations Management System with Cloud capabilities. This alternative was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. This alternative was not chosen as there would be a correlation gap between application services and the underlying infrastructure and would not address the ever-increasing resolution costs. (4) Develop and implement an on-premises service mapping and process solution. This alternative was chosen due to the value in Information Technology (IT) Operations Management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can utilize the Configuration Management Database (CMDB) and work hand-in-hand with asset discovery.	2023-10-01	2024-08-30	-1.00	3,012,243	699,524		902,130	889,961	-	410	2,865	221	8,663	221,782	198,873	-	105	22,742	63	-
99	2023	Nimbus Phase 5	Software(intangible)	I T Digital Foundation	Prior period adjustment.							(3,146)	(875)	-	-	-	-	(310)	9,185	7,047	-	2,138	-	-	-
100	2023	Operational Technology - Service Management Upgrade	Software(intangible)	I T Digital Foundation	This project will implement Operational Technology service management capabilities. Service management provides automated asset tracking, maintenance, and incident management for the assets. The Company's Internal Audit team conducted an audit of the Operational Technology (OT) assets environment and identified significant gaps in the patch management program. The patch management operating model is decentralized, has limited and inconsistent standards, doesn't have a company-wide governance structure to monitor all business areas of the Company and lacks a complete and accurate asset inventory. Due to the lack of a complete asset inventory, as well as a significant number of gaps identified in the patch management governance, operating model, processes, and controls to manage all assets within the Company's environment, an unknown magnitude of risk exists that critical patches were not installed timely, which could create the potential for increased security vulnerabilities. The project provides value to the Company in three ways: 1. It establishes a complete and accurate asset inventory. 2. Creates a Company-wide governance structure with documented standards and processes to manage the assets and 3) It defines a comprehensive patch management operating model with clearly defined roles and responsibilities. The project scope includes: (1) the implementation of an asset management tool (2) the implementation of an incident management tool, (3) and the establishment of processes to support the assets. Alternatives considered included: (1) Choose an alternate asset management system. This option was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. Continue to manually track or not track Operational Technology (OT) digital assets and the associated risk at the Company, which will not address the need to effectively track OT Digital assets and plan for their support. (4) Develop and implement an asset management and incident management tool and process. This alternative ultimately chosen has strengths in Information Technology's support for current version of Oracle; upgrade to Version 12c and beyond supported until those systems are upgraded.	2023-10-01	2024-08-29	-1.00	892,455	192,305		239,737	213,693	-	7,354	9,809	1,209	1,652	51,939	47,752	-	1,245	2,823	118	-
101	2023	Oracle Server Database Upgrade 2023	Software(intangible)	I T Digital Foundation	This project will upgrade Oracle server databases to the next version to support all business portfolios. The Company is currently managing Oracle server databases that run on multiple versions of Oracle 8i, 9i, 11g and 12c; all of which are currently unsupported as of 12/31/2020. Version 12c recently lost vendor support in July of 2019 and is eligible for extended support. Relying on extended support for Version 12c increases operational costs by $12,000 annually. Extended support is not available for version 11g and older. Without vendor support, the databases no longer receive security patches, bug fixes, or functional by support which creates security, stability, and reliability risks. This project will create value for the Company and its customers by (1) reducing the risk of system failure and the resulting impacts to business partners and customers; and (2) ensuring that systems are secure, supported, and have the latest features and functionality; and (3) will do what we can to be compliant with Cyber Security Published standards, when possible. Many of the Cyber Security requirements are application dependent. The scope of this project includes upgrading to the next version of Oracle across all impacted business systems. Systems that cannot support current version of Oracle, will be upgraded to the highest supported version. Alternatives considered were: (1) delay database upgrades. This option was not chosen because, as stated, it would introduce significant security, stability and reliability risks; (2) Upgrade only to Version 12c and pay extended support. This option was not chosen, where possible, to avoid increased operational costs. The alternative chosen is to upgrade to the next version of Oracle and where systems do not support the current version of Oracle, upgrade to Version 12c and pay extended support until those systems are upgraded.	2022-12-26	2023-11-27	-1.00	-	171,941		-	-	-	-	-	-	-	35,001	-	-	10,320	22,545	2,135	-
102	2023	Product Family Enhancements-Application Platforms Services-O&M	Software(intangible)	I T Digital Foundation	The I T initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	-	340		-	-	-	-	-	-	-	131	-	-	122	-	9	-
103	2023	Product Family Enhancements IT/Digital Foundation-Capital	Software(intangible)	IT/Digital Foundation	The I T initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	267,996	47,830		85,975	9,072	31,410	26,644	11,556	2,499	4,794	16,740	972	329	7,740	6,858	843	-
104	2023	Product Family Enhancements IT/Digital Foundation-O&M	Software(intangible)	I T Digital Foundation	The I T initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	-	39,832		-	-	-	-	-	-	-	15,162	-	-	5,565	8,597	1,001	-
105	2023	Public Key Infrastructure (PKI) Upgrade	Software(intangible)	I T Digital Foundation	Replace on-premises Public Key Infrastructure (PKI) that is no longer supported by the manufacturer with a system that is supported by the manufacturer. The existing Public Key Infrastructure (PKI) that issues certificates to IT systems for secure communications is out of support from the manufacturer. In the event of a system failure the Company would not have support in recovering. All IT systems requiring secure communications via certificates would go offline within three days. Replace existing Public Key Infrastructure with new Public Key Infrastructure that is supported by the manufacturer. The project will build and configure the servers necessary to provide Public Key Infrastructure services, put in place physical token management for maintaining security, migrate certificates using and management to the new system and decommission the old system. The alternative is a limited use service use for Public Key Infrastructure on the internet only. (1) The Company is locked into expanding the service to include usage on the Company network but found the solution to not be economically viable. (2) The Company also looked at full Cloud solutions, but did not meet the security standards currently being used around physical token use. (3) The Company looked at continuing extended support however the continuing extended support is not available by the Vendor. (4) The Company elected a hybrid solution of part Cloud and part On-Premise to meet all operational and security compliance requirements. The opportunity is to retain ownership of the keys on premise prior to evaluating ownership through the cloud	2023-10-02	2024-12-31	-1.00	1,818,198	423,977		49,398	49,224	-	-	-	-	134	29,550	18,206	-	5,152	5,551	642	-
106	2023	SAP Data Archiving	Software(intangible)	I T Digital Foundation	This project will move outdated data from an online database to offline storage. The SAP Enterprise Resource Planning Central Component database is 37 terabytes in size and growing at a rate of 0.3 terabytes to 0.5 terabytes per month. If the database is not archived, SAP system performance will degrade, and IT staff will affect customers and employees who are completing tasks within the system. The project will create value for the Company by: (1) increasing system stability by controlling online data storage levels; and (2) controlling maintenance costs associated with data storage. Annual data storage costs are $7,465 per terabyte only including the primary production system. Data back-up costs are $400 per terabyte per week for full back-ups. The project scope includes: (1) archiving data based on the fastest growing and largest archiving objects in SAP (an archiving object defines the structure and context of the data in the SAP database from an archiving perspective); (2) building and archiving solutions that allow retrieval of archived data in the required form; and (3) setting up a solution that meets compliance standards. Three alternatives were explored and determined non-viable for the project: (1) allow the database to continue to grow, which puts system performance at risk and must be prohibited as soon as possible; (2) decrease the overall scope and archive fewer objects, which would result in a significant cost increase over shorter time period. After considering each of these options, it was determined that the current scope of the project was the best strategy to address the problem while balancing annual spending.	2020-09-28	2023-05-29	-1.00	751,857	701,712		6,861	-	-	775	58	-	6,029	651	-	-	-	613	38	-
107	2023	SAP Support Pack Upgrade 2023-2024	Software(intangible)	I T Digital Foundation	The SAP Support Pack Upgrade project is to maintain the currency levels of all SAP applications. This will ensure the applications are at version levels that are supported by SAP, have the latest patches and bug fixes, and provide cross-application compatibility for our business partners. In the past, the SAP enhancement packs were applied to Company systems to ensure these problems were addressed in a timely manner. However, SAP is no longer releasing enhancement packs. To continue to maintain SAP application version currency, across all applications, the support packs released by SAP must be routinely applied. Without maintaining application currency, the core business applications running on the SAP platform are at risk of losing vendor support, resulting in the inability to apply bug fixes and patches, including security patches, and maintain application interoperability and stability. The project will add value by: (1) maintaining application stability of SAP applications; (2) mitigating system security, stability and reliability risks by ensuring the applications are up-to-date with the most current patches and bug fixes released by SAP; and (3) ensuring ongoing cross-application compatibility. The scope of this project includes routine support pack upgrades to all SAP applications, which include: Enterprise Core Component (ECC), Customer Relations Hip Manager (CRM), Enterprise Portal, Process Orchestration (PO), Business Warehouse (BW), Business Objects (BOBI), Data Services (DS), Governance, Risk and Compliance (GRC), Solution Manager, Data Quality Manager (DQM), Graphical User Interface (GUI), Single Sign On (SSO), System Landscape Directory (LD) and other related SAP applications. Alternatives considered include: (1) Divide the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and so replacing them separately could lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) Migrate to SAP S/4HANA. This option was not selected at this time because it is part of the long-term digital plan and requires substantial planning and investment. (3) Balance the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimizing cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.	2023-10-30	2024-10-31	-1.00	-	169,421		-	-	-	-	-	-	-	3,952	-	-	-	385	3,274	292	-
108	2023	SharePoint 2016 and IC2 4.7 Replacement	Software(intangible)	I T Digital Foundation	Prior period adjustment.							(8,059)	-	-	-	-	-	(8,059)	-	-	-	-	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synapse Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025, and 2026
Information Technology Department

REDACTED

Case No.: U-21806
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Date: December 2024

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	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
109	2023	Software As set - Service Management Upgrade	Software(Intangible)	IT Digital Foundation	This project will optimize the software asset management process by systematically monitor, assess and oversee software licenses and compliance using Software Asset Management Professional. The on-premises software asset management technology currently used in the Company lacks compatibility to automate license reclamation, cost optimization, and license forecasting. These software asset management constraints lead to the inability to optimize software license purchasing and effective license demand management. This project will create value by leveraging the Company's technology requirements are met through a comprehensive and cost-effective software asset management process and workflow. Specifically, by replacing the on-premise application, the project will: (1) streamline the software request workflow including license reclamation and software deployment; (2) help ensure compliance with software license agreements; (3) identify cooptunities of license optimization leading to cost optimization; (4) mitigate risk related to software asset management; (5) optimize future forecasting and (6) increase asset visibility. The project scope includes: (1) the implementation of software asset management tools; (2) the establishment of the process and process roles needed to support the assets; and (3) retirement of the on-premise software asset management tool. Alternatives considered included: (1) Choose an alternate Cloud based as set management system. This alternative was not chosen as it would require introducing and migrating a second vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain similar capabilities and to integrate the custom solution would not be fiscally or cost effective. (3) Do nothing. This alternative was not selected as the current Software Asset Management tool that lacks integration and automation and will not address optimizing and effective management of licenses and purchases. (4) Develop and implement an on-premises software Asset Management solution. This alternative ultimately shows on has strengths in software as set management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can helps license compliance, optimization and automation.	2023-06-01	2024-08-15	-0.80	1,120,674	260,229		336,878	211,920	-	23,163	92,580	4,167	5,067	63,036	47,256	-	785	14,827	68	-
110	2023	Software Platform Refresh	Software(Intangible)	IT Digital Foundation	This project will upgrade several operating systems, hypervisors (virtual machine monitors), and databases to retain low-cost, unlimited vendor support. For systems that go beyond their normal manufacturer support ending, there will be increased support and maintenance fees of 20% to 100% above current support and maintenance depending on vendor. Completing this project allows the organization to (1) avoid high support costs; (2) provide for system security; and (3) stay current to promote seamless interoperability among servers, applications, and databases. Aging servers are more susceptible to security vulnerabilities and performance issues that ultimately could affect the business and customers. The project will add value for the Company by: (1) avoiding costs for special maintenance agreements required at the end of normal manufacturer support; (2) ensuring reliability and compliance with Information Security requirements; (3) improving data center environment stability; and (4) avoiding the need for high risk upgrades that cross multiple versions. The project scope includes: (1) upgrading operating systems and databases on servers that are near end of support with its given vendor; and (2) maintaining servers on the current version for stability and performance. A funding options matrix was completed to review the potential alternatives. The alternatives identified were: (1) Complete the full scope of the solution for $1 million in order to eliminate the need for ongoing extended support; (2) Reduce the scale of the solution, which requires $1.6 million in ongoing extended support; (3) Reduce the scale of the solution even further, which requires $2.4 million in ongoing extended support; (4) Do not complete a software platform refresh, which requires $3.7 million in ongoing extended support. Alternative 1 was selected as the most cost effective solution to ensure ongoing system stability, seamless integration, and mitigation of cyber security risks without the significant cost of extended support necessary for End of Life software systems.	2023-01-01	2023-12-31	-1.00	-	138,217		-	-	-	-	-	-	-	53,067	-	-	33,981	15,996	3,089	-
111	2023	SolarWinds Performance Monitoring Expansion Upgrade	Software(Intangible)	IT Digital Foundation	This project will develop an IT observability and monitoring solution that provides an aggregate view of IT system availability and performance. The current IT enterprise monitoring approach doesn't provide a comprehensive view of application and infrastructure health resulting in unplanned service interruptions, extended service interruptions, and system performance degradation. In addition, unplanned service interruptions have a negative impact on business partners ability to provide reliable services to utility customers. The SolarWinds Expansion project will allow IT to reduce the number of monitor rigids and consolidate end-to-end view of IT performance metrics to a single pane of glass. These actions will prevent major service interruptions, reduce Major Incident Mean Time to Restore (MTTR), improve IT system stability, and ultimately reduce O&M labor cost. This project scope includes: i) Perform proof of value (POV) assessment for the following SolarWinds modules, Hybrid Cloud Observability (HCO)/Database Performance Analytics (DPA)/AppOptics/Pingdom; (2) Transition applications monitored by AppDynamics to SolarWinds. 1) Deploy set configure agent base infrastructure monitors for applications and infrastructure 4.) Retire AppDynamics 5.) Transition critical applications not monitored by AppDynamics to SolarWinds 6.) Create performance monitoring rigids/boards for critical systems 7.) Define monitoring templates for rapid deployment of new monitoring services 8.) Training of the product/Platform Transition user and management of SolarWinds. Several monitoring tools were considered to manage alerts and escalation on Consumers Energy IT application and infrastructure ecosystem. Other considerations included our ability to consolidate other monitoring tools into a single tool and reduce licensing and maintenance cost. Below are the alternatives that were considered. 1). Renew current licenses for both SolarWinds and AppDynamics without achieving any savings or operational efficiencies. 2). Considered other vendors like Dynatrace to replace AppDynamics at a reduced cost for services, but initial deployment and annual cost would significantly increase regardless of service selected. In addition, the other vendors considered didn't have the capabilities to monitor both application and infrastructure ecosystem which didn't allow for a consolidated approach to be adopted and/or reduction in licensing and ongoing maintenance cost. As a result, the other vendors considered were not an option. 3). In conclusion, SolarWinds was determined to be the most cost-effective response because of the expanded capabilities offered over the following modules, Hybrid Cloud Observability (HCO)/Database Performance Analytics (DPA)/AppOptics/Pingdom that meets the needs of IT to proactively monitor IT systems and retire tools with similar capabilities to reduce ongoing maintenance cost. Therefore, our decision is to move forward with deploying the expanded services offered by SolarWinds.	2023-03-27	2024-08-25	-1.00	1,766,608	336,026		585,466	481,809	-	32,919	40,668	3,425	6,648	116,264	107,781	-	3,444	4,510	530	-
112	2023	SQL Server Database Upgrade 2020-2022	Software(Intangible)	IT Digital Foundation	Prior period adjustment.							(1,591)				(57)	(1,269)	(113)	(152)	2,910			2,142	690	78	-
113	SUBTOTAL	2023 IT Digital Revolution										11,847,204	3,784,641	6,290,871	926,208	1,422,320	74,186	348,625	1,723,520	406,367	94,552	484,065	690,250	63,355	11,420
114	2023	AFP-Cyber Security	Network	Security	This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions. When enterprise software or cyber security infrastructure aid to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates. This project will create value by maintaining the currency of cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations. The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a 3-5 year hardware lifecycle; and (2) performing application upgrades. As part of the review process, the alternatives considered were to: 1) upgrade or replace each of the assets identified in the plan. Option 1 was not chosen because it would not address the risk of obsolescence and the inability to patch or cyber security assets to avoid security risks, system vulnerabilities, and out-of-warranty repair costs. Option 2 was not chosen due to the security risk inherent with not replacing assets as per standard refreshcycles increased system vulnerabilities, and stated warranty repair costs.	2023-01-01	2023-12-31	-1.00	-	-		-	(27,291)	27,291	-	-	-	-	-	-	-	-	-	-	-
115	2023	Pipeline SCADA Security	Network	Security	This project will implement major modifications to the Gas Supervisory Control and Data Acquisition (SCADA) environment to ensure compliance to American Petroleum Institute (API) 1164 standard. API 1164 is an NPMC regulatory requirement with recent updates, to the Gas Technical Standards. The project will implement IT, cyber security, and physical security equipment and site modifications necessary for regulatory compliance to API 1164. The NPMC requires the implementation of pipeline cyber security regulations pursuant to API 1164 on the Company natural gas pipeline system. The Company's Gas SCADA system is outdated and non-standardized, requiring significant modifications to be compliant with API 1164. Without the technology updates, the gas SCADA system is vulnerable to cyber attacks that potentially risk disrupting delivery to customers. Interruptions in gas delivery and compliance could be subject to fines and penalties from the NPMC and other regulatory entities (i.e., the Transportation Security Administration's). This project will add value to the Company by: (1) modernizing and standardizing the Gas SCADA network at the Company's gas compressor stations and control rooms; (2) mitigating cyber security vulnerabilities in the Gas SCADA network; (3) allowing the Company to fully comply with API 1164 requirements; and (4) fulfilling the commitment to the NPMC to provide a secure gas system that meets customer needs. The project scope includes updates for multiple gas SCADA-related locations, including eight gas compressor stations, two gas control rooms, two data centers, and multiple intelligent pipeline field devices. To establish compliance with API 1164, the project will: (1) design a holistic network architecture to implement both physical and technical barriers; (2) implement physical enhancements to impacted facilities, such as additional doors or data rooms, and modified HVAC systems to provide necessary climate control for the SCADA equipment; (3) install additional security cameras and/or card readers necessary to control access to new and existing equipment; (4) complete technology upgrades requiring design, development, testing and implementation for the Gas SCADA network at each of the planned locations. Upgrades will consist of endpoint protection, identity and access management, vulnerability management, business continuity capabilities, cyber incident response, asset management, and commensurate test environments; and (5) implement additional security measures to accomplish the new camera system(s). Site construction work of trenching, pole, etc.; (10) Facility lighting; (11) badge card investigation for personnel working at the site; (12) security equipment maintenance and testing; (13) security vulnerability assessments; (14) security communication plans; (15) personnel training; (16) security drill and exercises for the following locations. These activities will be performed at the following company locations: Owners of Freedom, Northville, Muskegon Fuel Center. Alternatives are not available because this is a compliance mandate from the TSA.	2020-06-01	2024-10-28	-1.00	12,592,731	542,854		3,409,966	33,530	190,353	1,004,358	1,757,458	69,554	354,710	184,227	55,291	5,435	12,217	61,284	-	-
116	2023	Security Island Protocol	Network	Security	Prior period adjustment.							-	-	-	-	-	-	-	7	-	-	7	-	-	-
117	2023	TSA Critical Facility Structure	Network	Security	This project will implement enhanced security measures outlined by the Transportation Security Administration (TSA) for critical facility assets in order to bring the locations up to enhanced status and avoid non-compliances. This project will increase the security and reliability of gas delivery to our customers while also meeting federal requirements Pipeline facilities that are deemed critical are required to apply enhanced security measures. Today, Consumers Energy currently has designated 4 locations as critical. However, based on the April 2021 update to the TSA Pipeline Security Guidelines, Section 5 (Critical Facility Criteria), a significant number of our gas infrastructure that were not previously subject to evaluation will now fall into scope. As we continue to analyze the remainder of our gas assets, we believe an additional 1000 pipeline facilities (pipeline interconnection, metering and/or regulating stations, pump stations, compressor stations, operational control facilities, main line valve, tank farms and terminals, etc.) may be deemed critical. Consumers Energy will be taking a phased implementation approach and will begin the process by implementing the enhanced security measures at the reminder of our compressor stations. Failure to update our sites will put us out of compliance with the updated guidelines. The objective of the project is to implement enhanced security measures outlined by the TSA for the following four critical assets: (1) Freedom Compressor, (2) Mackinaw River Compressor, (3) Overall Compressor, and (4) Northville Compressor. In order to bring these locations up to Enhanced status and avoid non-compliance. This project will increase the security and reliability of gas delivery to our customers while also meeting federal requirements Enhanced measures that will need to be implemented include, but are not limited to: (1) access controls; (2) access readers; (3) cameras; (4) video and audio programming; (5) fencing and barriers; (6) gates; (7) locks and key control; (8) fence intrusion (which may be accomplished with a new camera system); (9) subcontractor work of trenching, pole, etc.; (10) Facility lighting; (11) badge card investigation for personnel working at the site; (12) security equipment maintenance and testing; (13) security vulnerability assessments; (14) security communication plans; (15) personnel training; (16) security drill and exercises for the following locations. These activities will be performed at the following company locations: Owners of Freedom, Northville, Muskegon Fuel Center. Alternatives are not available because this is a compliance mandate from the TSA.	2023-11-27	2025-12-28	-1.00	9,088,335	584,724		1,648,968	-	482,496	40,576	1,156,229	-	12,752	33,409	-	-	32,279	487	3	641
118	2023	ARP-Physical Security	New Computers / Hardware	Security	This project will enhance or replace physical security assets to provide improved visibility and incident resolution related to security concerns. The Company has several thousand physical security asset devices currently in use including security camera, motion detectors, intrusion detection systems, and card access systems. Current limitations include the lack of integrated solutions for centralized management, situational awareness, real time monitoring, compliance with regulations and guidelines, and faster response to emergencies and incidents. This could result in the increase of potential security vulnerabilities, associated penalties, and reputational damage. The value provided by completing the project is to: (1) maintain compliance with State and Federal Regulations; (2) reduce redundancies with less of a need for multiple cameras and reducing gaps in functionality; and (3) optimize overall system performance. Included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) security cameras for monitoring capabilities; and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detection systems, and card access systems. Alternatives considered include: (1) not refreshing physical security assets, and (2) defer a portion of the refresh of physical security assets per asset refresh cycle industry standard. Alternatives 1 and 2 were not selected due to the risk of security concerns, incident resolution, and the inability to meet FERC requirements. The alternative selected maintains compliance, reduces redundancies and gaps in functionality, and optimizes overall performance of physical security systems.	2023-01-01	2023-12-31	-1.00	1,437,957	13,517		468,297	-	256,170	78	199,948	-	5,105	4,731	-	-	4,731	-	-	-
119	2023	CRSP	New Computers / Hardware	Security	Prior period adjustment.							-	-	-	-	13,450	-	(13,450)	-	-	-	-	-	-	-
120	2023	Radar Intrusion Detection	New Computers / Hardware	Security	This project will deploy new radar detection technology to enable the detection and tracking of individuals at Company sites. The radar will alert in real time and automatically dispatch Company security or law enforcement to investigate. The Company currently lacks the ability to detect potential intruders at Company sites across the state, including critical infrastructure sites such as city gates, compressor stations, substations, generation plants, and hydro stations. Currently, three sites have flawed fence intrusion detection technology that result in the occurrence of multiple false alarms that require an employee to investigate. Additionally, the current detection technology is unable to identify the difference between animals and humans, cannot set different boundaries, and prohibits the expansion of intrusion detection in an area other critical sites. Any investigation that has to be done is hampered by the limitations of the current system, requiring manual frame by frame review of video playback is manually intensive and time consuming. Completion of this project will provide value to the Company through evaluating and selecting a more reliable intrusion detection solution that reduces the number of false alarms and prevents resources from indexing sent to a site for unnecessary investigations. Additionally, the project will improve the efficiency of investigations by reducing the amount of time it takes to review playback to develop a suspect or investigative lead. In most cases this will be eliminated completely. This added layer of security benefits both the Company through waste elimination, as well as the Company's customers through the safety and security of assets necessary to continue to serve. The scope of this project encompasses: (1) implementing radar intrusion detection options; (2) establishing a priority list of sites where the solution will be rolled out; and (3) installing updated radar intrusion detection systems with a focus on initial deployment at infrastructure sites, including compressor stations, electric substations, and hydro-electric sites. Alternatives considered included: (1) keeping the current fence intrusion detection solution; or (2) implementing a new intrusion detection solution. The preferred option is to implement a new solution, given the above limitations with the current solution.	2019-12-30	2024-08-29	-1.00	2,960,419	10,245		130,089	-	200,138	7,233	(90,057)	498	2,277	-	-	-	-	-	-	-
121	2023	Application Currency-Security Capital	Software(Intangible)	Security	This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyber threats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Security portfolio adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; (4) address ing version interdependencies and compatibility between systems; and (5) allowing the Company to leverage additional functionality available in the upgrades; (6) provides customer value through closing the gaps on vulnerabilities that can impact reliability; (7) provides a mechanism for proactive actions to stay ahead of evolving cyber threats. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Security portfolio are routinely evaluated to determine if upgrade efforts are necessary to maintain an appropriate level of currency and then prioritized accordingly. During that evaluation process, the alternative of delaying the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application's current and risking failure; (2) an increase in the number of incidents; (3) paying increased support costs; and (4) prevention of employees from performing their daily tasks. This project is ongoing upgrades and supports these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	20,319	2,240		319	-	-	-	-	-	359	784	470	-	314	-	-	-
122	2023	Application Currency-Security O&M	Software(Intangible)	Security	This project will utilize both O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrade. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyber threats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Security portfolio adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality; (4) addressing version interdependencies and compatibility between systems; and (5) allowing the Company to leverage additional functionality available in the upgrades. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Security portfolio are routinely evaluated to determine if upgrade efforts are necessary to maintain an appropriate level of currency and then prioritized accordingly. During that evaluation process, the alternative of delaying the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application's current and risking failure; (2) an increase in the number of incidents; (3) paying increased support costs; and (4) prevention of employees from performing their daily tasks. This project is ongoing upgrades and supports these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2023-01-01	2023-12-31	-1.00	29,258			-	-	-	-	-	-	-	14,364	-	-	14,287	-	78	-
123	2023	Enhancements-Security Capital	Software(Intangible)	Security	This initiative will use Capital funding to make enhancements to existing technology to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements in accordance with accounting rules. As business conditions improve and change, compliance requirements evolve, and new capabilities are needed, new requirements surface that call for smaller effort software application changes (enhancements). Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, limit the Company's ability to consistently meet objectives, and increase security risk. The value of technology enhancements in the Security Portfolio lies in: (1) enhancing security protections by funding emerging or unplanned cyber security activities resulting from audits, incidents, or a changing threat landscape; (2) addressing the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage additional functionality available in the technology. The scope of technology applications encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board that routinely evaluates and prioritizes the work. Security enhancements fortify the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes in a fast and nimble manner. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	1,269,946	267,035		727,662	196,286	28,162	144,075	295,738	3,549	59,863	67,100	-	-	59,622	6,523	954	-
124	2023	Enhancements-Security O&M	Software(Intangible)	Security	This initiative will use O&M funding to make enhancements to existing technology and to address requests generated by changing business requirements. As business conditions improve and change, compliance requirements evolve, and new capabilities are needed, new requirements surface that call for smaller effort software application changes (enhancements). Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, limit the Company's ability to consistently meet objectives, and increase security risk. The value of technology enhancements in the Security Portfolio lies in: (1) enhancing security protections by funding emerging or unplanned cyber security activities resulting from audits, incidents, or a changing threat landscape; (2) addressing the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage additional functionality available in the technology. While these work efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing technology investments for Security. The scope of technology applications encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and assesses requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2023-01-01	2023-12-31	-1.00	-	631,654		-	-	-	-	-	-	-	283,491	14,177	-	190,927	23,644	4,705	39
125	2023	Privacy Management Platform	Software(Intangible)	Security	Prior period adjustment.							(5,518)	-	-	-	(5,196)	(303)	(16)	-	-	-	-	-	-	-
126	2023	SAP ISN Integration	Software(Intangible)	Security	Prior period adjustment.							(10,056)	-	-	-	(10,056)	-	-	-	-	-	-	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

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Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	RERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALIZED FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
127	2023	Saviynt Enterprise Identity Governance and Access (EIGA) Implementation	Software(intangible)	Security	The project will implement Saviynt EIGA module, consolidate Identity Access Management (IAM) functionality into Saviynt, and retire the Identity Manager application. By implementing the new solution, the Company will optimize IAM functionality, eliminate complexity, and reduce support costs. In addition, the project will integrate the OT network with an IAM solution that will allow for automated management of users and entitlements in the OT Active Directory domains and applications. The current version of Access Now reached end-of-life in December 2022, with support discontinued in January 2023. The application has numerous custom workflows and integrations, requiring professional services for ongoing use and changes. It lacks proper data analytics and reporting, posing risks such as inability to fix critical defects, software incompatibility, compliance issues, increased costs, and degraded performance. The Company uses multiple IAM tools, each performing critical functions, leading to numerous required interfaces and customizations. While a benefit for end users, these integrations increase the risk of system failures, higher support costs, multiple subscriptions, infrastructure and maintenance costs, and more expensive upgrades. The current solution utilizes SAP HR batch file processes that introduce full-set points, delays, and data integrity issues. Failures in these processes can prevent new or transferred employees from accessing necessary systems, leading to operational disruptions and potential compliance risk due to inappropriate access retention. This project provides value by: (1) Consolidating multiple IAM platforms through the implementation of the Saviynt Enterprise IGA Module, reducing complexity and support costs; (2) Decreasing complexity and enhancing efficiency by reducing interfaces between multiple identity tools; (3) Improving the end-user experience and reducing human struggle with access requests through a new, intuitive portal design; (4) minimizing custom code and focusing on out-of-the-box functionality; and (5) Streamlining employee data processing with the implementation of an HR interface. This project scope includes: (1) Implementing the Saviynt EIGA module to consolidate IAM platforms; (2) Standardizing processes by removing customized code and using out-of-the-box functionality; (3) Replacing and improving access systems (ASA addressing issues with aging application vs. multiple IAM platforms, integration challenges, and antiquated HR processing. Alternatives considered include: (1) Implementing hot fixes to Access Now version 8.1.5 to ensure support through mid-2023; (2) Upgrading only the application to current supported version, excluding the new web portal but will including new application functionality; (3) Remaining on current version that will be unsupported as of January 2023, requiring vendor professional services for any break/fix. Patches and enhancements may potentially introduce additional risk of version instability; (4) Implementing IAM functionality in Saviynt platform to manage access requests, including Active Directory, SAP, SAP HR, disconnected systems, and existing API integrations. The alternative selected was implementing the new Saviynt system, eliminating Accesshow software.	2023-11-27	2024-12-30	-1.00	5,913,132	710,912		-	-	-	-	-	-	-	1,141	-	-	-	1,052	88	0	-
128	2023	Security Analytics	Software(intangible)	Security	Prior period adjustment.							-	-	-	-	-	-	-	6	6	-	(4,561)	4,250	311	-
129	SUBTOTAL	2023 Security										6,347,758	201,516	1,147,969	1,196,100	3,292,644	73,300	434,999	489,260	69,983	5,485	310,876	96,271	6,056	680
130	TOTAL	2023										23,620,499	6,092,764	8,463,335	3,168,993	8,141,761	373,718	1,379,928	4,395,275	539,089	134,184	1,420,536	2,130,122	174,038	16,634
131	2024	Application Currency-Corporate Services-O&M	Software(intangible)	Corporate	The Corporate Services initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Corporate Services adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application currency security and operational risks, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application to Fusion, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Corporate Services are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increase number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrade and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2024-01-01	2024-12-31	-1.00	-	493,488		-	-	-	-	-	-	-	180,978	-	-	-	172,505	14,304	168	-
132	2024	Asset Accounting Upgrade	Software(intangible)	Corporate	The project will upgrade our current accounting asset management software to the latest version as required by the vendor and implement additional new feature, ensuring continued support of a critical financial application and providing new functionality. In 2022, standard vendor support ends for the current on-premise software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the new version vendor support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial reporting and improve visibility. The current monthly allocation process has limited visibility to Company financial performance, and the upgrade provides functionality that allows more frequent allocation processes. Additionally, implementing the vendor's regulatory module eliminates the time-consuming and labor-intensive process of manual data extracts for regulatory analysis used for Cost of Service modeling. This project creates value for the Company by ensuring compliance with regulated financial accounting within the fixed asset sub ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) eliminating the labor intensive and time-consuming process of pulling data for regulatory analysis used for Cost of Service; (3) automating financial tasks and; (4) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support. The project scope includes: (1) upgrading the vendor software from the current version to the newer version; (2) implementing new functionality that includes features for the regulatory Cost of Service analysis, additional reporting, job scheduling, and central load error processing; and (3) populating the data lake with data from the asset accounting system. Alternatives considered include: (1) Upgrade to the newest cloud version of PowerPlan. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrade, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service reporting, and centralized error processing. (2) Evaluate SAP options for leasing, asset, and tax management capabilities. While this option would initiate the need for an interface between SAP and PowerPlan, it would likely be more complex, cost more, and may not provide all the required features. (3) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements.	2021-09-27	2023-12-25	-0.99	4,630,550	260,286		-	-	-	-	-	-	-	10,089	-	-	-	-	10,089	-	-
133	2024	HR Support Pack and Business Software Inc Upgrade 2023	Software(intangible)	Corporate	The HR Support Pack and BSI upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes. SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll. This project creates value for the Company by: (1) ensuring that its system is in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll. The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company. As this is an upgrade of an existing system, the alternative considered was to delay the upgrade. This alternative was not chosen due to the risk of not complying with financial rules and regulations.	2022-12-26	2024-01-22	0.00	-	664,262		-	-	-	-	-	-	-	6,530	-	-	-	825	5,282	423	-
134	2024	HR Support Pack and Business Software Inc Upgrade 2024	Software(intangible)	Corporate	The HR Support Pack and BSI upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes. SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll. This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll. The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company. As this is an upgrade of an existing system, the alternative considered was to delay the upgrade. This alternative was not chosen due to the risk of not complying with financial rules and regulations.	2024-03-25	2024-12-08	0.00	-	569,446		-	-	-	-	-	-	-	315,758	-	-	-	44,884	164,612	6,262	-
135	2024	Product Family Enhancements Corporate Capital	Software(intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. A business process improvement and change, new requirements surface that call for small-or-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Corporate Services Portfolio is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing Tier 3 software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and Public Affairs. Prior to implementation enhancement, a review is completed to identify the best solution. During that review, requests for this fund are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	1,813,930	119,298		510,538	110,838	-	318,419	102,706	3,278	15,197	44,140	27,676	-	-	2,556	13,864	45	-
136	2024	Product Family Enhancements Corporate O&M	Software(intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business process improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Corporate Services Portfolio is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and Public Affairs. Prior to implementation enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	-	185,469		-	-	-	-	-	-	-	70,273	-	-	-	18,627	50,451	1,195	-
137	2024	Talent Management Enablement	Software(intangible)	Corporate	The project will deliver technology solutions to enable best-in-class Talent Management programs and processes that are critical to achieve the Company's overarching Talent Strategy Plan. The Talent Strategy Plan is a key enabler of the Company's Integrated Resource Plan (IRP), Electric Distribution Infrastructure Investment Plan (EDIIP), and Natural Gas Delivery Plan (NGDP). Effective Talent Management programs and processes are critical to develop the skills, capabilities, productivity, and experience necessary to successfully execute these plans that deliver clean, reliable, affordable energy through an exceptional customer experience. Significant technology improvements are required to transform human resources (HR) to develop the skills and capabilities necessary to achieve the Company's strategic destination. Currently, many Talent Management processes are manually managed with little or no technology enablement. Specifically, the talent compensation process are mostly manually done outside the system which introduces waste, and a potential for errors. In addition there is a limited visibility of competency gaps within the workforce. The Company cannot effectively place talent in accelerated development programs aligned to competency gaps, nor can it recognize and motivate employees for quickly increasing competency and performance. Furthermore, the Company operates in an increasingly competitive job market where candidates and employees expect best-in-class processes, technologies and experiences relative to their employment and career development. The lack of full technical enablement across Talent Management programs can pose a risk to employee attraction, retention and limits the ability to develop the right skills at the right time to deliver on Company strategies. This project will add value to the Company through technology that will enable: (1) fully funded and integrated compensation modules; (2) accelerated and targeted talent development of critical skill areas sets to deliver on the Company's commitment to clean energy and exceptional customer experience; (3) transparency into talent and skill gaps to inform succession planning and business continuity and career development; (4) Career Development and Employee Retention. The scope will include: (1) implementation of each system/application; (2) integration with current systems, applications and processes as applicable; (3) retrofit current systems and applications to ensure a seamless end-to-end experience of HR processes; (4) delivery of mobile capabilities for in-scope processes; (5) reporting and analytics dashboards and insights for in-scope processes. Three alternatives were considered for these Talent Management programs and processes: (1) develop custom, internally built solutions that do not meet most requirements. This alternative was not selected because a custom solution would result in higher overall costs, higher maintenance costs, fewer upgrades, and would not leverage industry best practices to ensure best-in-class delivery. (2) Select an incumbent software tool. This alternative was not selected because it requires internal maintenance, increases infrastructure costs, and would have less frequent upgrades which would hinder the Company's ability to ensure processes are evolving alongside industry trends and best practices. (3) Evaluate and select dual/SaaS solutions) which would lower infrastructure costs, less internal maintenance than an on-premise solutions and would be built and evolved with upgrades based on industry best practices. Based on research, internal experience with successful best practice implementations, and vendor demonstrations, option three was selected.	2023-02-27	2025-12-19	-1.00	1,221,532	464,821		138,825	-	-	117,915	14,687	1,073	150	61,152	-	-	-	704	59,338	1,110	-
138	SUBTOTAL	2024 Corporate										684,353	110,838	-	436,334	117,482	4,351	15,347	594,920	27,676	-	280,101	317,939	9,203	-
139	2024	Application Currency-CoBo Capital	Software(intangible)	Customer	The CoBo initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct, negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the CoBO adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risks; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application on software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes. Applications within the CoBO are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2024-01-01	2024-12-31	-1.00	-	90,993		-	-	-	-	-	-	-	18,278	-	-	-	5,466	12,559	254	-
140	2024	Click to Chat	Software(intangible)	Customer	Prior period adjustment.							2,958	77,921	-	166	(76,993)	-	1,821	132	-	-	-	124	9	-
141	2024	Energy Assistance Enhancements and Maintenance Annual Updates	Software(intangible)	Customer	The Energy Assistance Enhancements and Maintenance Annual Updates project, formerly known as Consumers Affordable Resource for Energy (CARE) project, will implement software changes to offer energy assistance to low-income customers and streamline the process for the assistance agencies who use the assistance portal. This is accomplished through improved user interfaces and updates to SAP to process various requests. Upcoming modifications to the CARE credit forfeiture, ongoing and annual review of requests, that includes criteria from the Department of Health and Human Services (DHHS) and Michigan Public Service Commission ("MPSC") to prioritize the list of changes. Each grant year, DHHS and MPSC stipulate the criteria required for customers to enroll in the CARE program, how the Company and agencies will manage the enrollment process and track and report customers, and how they will administer the Energy Assistance Program ("EAP") Benefit through bill credits and arrears forgiveness. The criteria changes significantly each year; therefore, the Energy Assistance Enhancement and Maintenance Annual Updates application requires modifications to meet the new requirements. If the regulatory requirements are not fulfilled, the Company is at risk of losing state Low-Income Home Energy Assistance Program ("LIHEAP") funds to assist low-income customers with paying their energy bills, thereby increasing the customers risk of shutoff for non-payment. In addition, our energy assistance programs function within all software platforms in the company which consistently need enhancements and updates. The project will provide the following value: (1) complete modifications to internal SAP applications and the Company Portal to receive LIHEAP funding, which can be used to provide customers the bill credits and arrears forgiveness; (2) improve the data within the assistance agencies portal, thereby making it easier to assist customers in need of LIHEAP funding; and (3) complete modifications to customer facing platforms. The project scope includes: (1) updating the enrollment and status process; (2) allowing for two mid-year bills; (3) improving reporting; (4) updating the arrears forgiveness plan; (5) satisfying additional regulatory requirements for the annual grant rule changes required by the Department of Health and Human Services and Michigan Public Service Commission; (6) updating CARE during a process; and (7) updating CARE PASS functionality to enhance Agency Self-Service. Alternatives considered included: (1) continue with current process, which would lead to loss of grant funding, thus decreasing or eliminating energy assistance dollars for customers; (2) transfer administration of Energy Assistance Programs to a third party organization, which would remove ownership and visibility into the health of the program while increasing administrative costs; and (3) make annual updates to the application, which will allow agencies to easily enroll customers on assistance programs and allow placement of holds to stop or prolong credit activity until assistance decisions are granted. Option 3 was selected since it provides long-term proactive energy assistance to customers and prevents loss of grant funds. Changes are required to internal systems (SAP, Agency Portal, etc.), therefore a status or third party alternative is not viable. Additionally, retiring the existing Agency Portal for a new application would increase costs beyond that of the routine upgrades.	2024-01-01	2024-12-31	0.00	-	348,712		-	-	-	-	-	-	-	132,124	-	-	-	88,140	40,865	3,118	-
142	2024	Enhancements - Customer Experience and Operations - Cap	Software(intangible)	Customer	The CoBO initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business process improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the CoBO Portfolio is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for CoBO. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience Operations, Applications Support and Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this fund are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	516,561	24,459		196,776	-	-	80,519	60,189	3,831	12,037	9,050	-	-	-	5,233	3,716	100	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	RERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
143	2024	Enhancements -CX&D-O&M	Software(Intangible)	Customer	The CX&D initiative will utilize O&M funding to make enhancements to existing technology and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for small-effort technology changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing technology requires a short timeframe between inception and implementation. Failure to make these changes or to update aging technology can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of technology enhancements in the CX&D Portfolio is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT technology investments for CX&D. The scope of technology enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	-	184,758		-	-	-	-	-	-	-	70,003	-	-	-	36,978	31,507	1,518	-
144	2024	Genesys Cloud Migration	Software(Intangible)	Customer	The project will migrate the Company's existing on-premise customer contact solution and deploy it to the Genesys Platform As A Service (PAAS) cloud-based solution. It will provide the Company with the ability to reduce operational costs for performing upgrades and maintenance, take advantage of new enhancements offered by the vendor, and ensure continued support of a critical customer communication channel. In 2018, standard vendor support ended for the current on-premise contact center software and extended support is not available from the vendor. Without vendor support, the application no longer receives security patches, bug fixes, or functionality support from the vendor, which creates security, stability, and reliability risk. With the upcoming end of standard support, the vendor is no longer offering feature enhancements to the current on-premise solution limiting the Company's ability to invest in new ways to better serve its customers. This project will provide value to both the Company and its customers through: (1) reducing costs with cloud allocated hardware scalable to current usage needs; (2) reducing operating costs with vendor managed feature updates and maintenance provided without service disruption; (3) providing access to new and innovative capabilities to enhance customer service; and (4) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support. The project scope includes: (1) deploying the new PAAS cloud-based solution in the vendor cloud environment; (2) installing a new internet circuit to directly connect the Company's systems to the vendors cloud environment; (3) updating existing customer interactive voice response (IVR) logic to accommodate the new cloud implementation; and (4) implement new features supporting analytics, quality, and reporting. Alternatives considered include: (1) Defer to later years. The alternative was not selected due to rapid upgrades of existing on-premise hardware, increasing our ability to take advantage of new features offered by the cloud solution and reducing cost savings opportunities presented by moving to the cloud. (2) Deploy Genesys on-premise solution to new on-premise hardware. This alternative was not selected due cost associated with purchasing new hardware and does not address the security, stability, and reliability risk resulting from the vendor end of support for the on-premise software. (3) Select and migrate to a new vendor software. This alternative was not selected due to the complexity of our existing internal integrations base and the Genesys platform and the Company's other internal systems. As a result, selecting a new system that a new vendor would make the switch over prohibitive. (4) Migrate to the Genesys Cloud platform. This alternative was selected due to it building on the Company strategy of moving to cloud, reducing operating and maintenance costs, and reduce risk by ensuring consistent, seamless vendor support.	2024-07-02	2025-08-28	-0.80	-	8,808,452		-	-	-	-	-	-	-	47,623	-	-	-	1,589	45,987	47	-
145	2024	Product Family Enhancements -Customer-Capital	Software(Intangible)	Customer	The Customer initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Customer Portfolio is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	1,732,927	824,913		525,948	-	-	45,778	452,806	10,774	16,587	305,218	-	-	-	20,674	281,042	3,501	-
146	2024	Product Family Enhancements -Customer-O&M	Software(Intangible)	Customer	The Customer initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Customer Portfolio is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	-	33,847		-	-	-	-	-	-	-	12,824	-	-	-	892	11,709	224	-
147	2024	Rate Change Maintenance	Software(Intangible)	Customer	The Rates Case Implementation project will modify SAP billing in accordance with pricing and rate change requirements. For the Company to continue to meet and comply with the Michigan Public Service Commission (MPSC) rate change requirements, there is a need to make periodic updates/modifications to the existing prices and rate structures. These updates help ensure accuracy of billing and provide optimal rates for customers. The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing; (2) optimized rate configuration enabling rate changes to be made more efficiently; and (3) timely updates to Company applications that incorporate mandatory changes to the rate structure that include new surcharges, price changes, and energy efficiency programs. The scope of this project encompasses: (1) implementation of annual or monthly (or both) rate changes, rate structure changes as approved by the MSPC; and (2) optimizing the rate configuration in the Company's back-end systems for more efficient rate changes. An alternative considered for this effort was a fully dedicated offshore development model. The option ensured resources were readily available with a more cost effective hourly expense. This alternative was not chosen due to the risk of billing inaccuracies and customer complaints. These risks were deemed too high due to the complexities of the rate structure, new development, and the timing it would take for testing of this model. Cloud is not an applicable option in this case as we are not replacing any software. The option to use onshore resources to plan, coordinate, and execute the rate changes was selected as it supports the Company's operation model for rate changes.	2024-01-01	2024-12-31	0.00	-	278,944		-	-	-	-	-	-	-	105,689	-	-	-	689	102,718	2,282	-
148	2024	SheCore Upgrade	Software(Intangible)	Customer	Prior period adjustment.														7	-	-	-	7	-	-	-
149	**SUBTOTAL**	**2024 Guidewire**										**685,678**	**71,921**	-	**126,463**	**436,243**	**14,436**	**31,445**	**700,049**	-	-	**159,669**	**530,227**	**11,153**	-
150	2024	Application Currency-Electric & Gas Shared-Capital	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities as associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber-security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Electric and Gas Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2024-01-01	2024-12-31	-1.00	714,106	342,288		236,738	160,216	-	31,339	13,952	886	10,937	326,647	40,538	-	86,108	-	-	-	-
151	2024	Application Currency-Electric & Gas Shared-O&M	Software(Intangible)	Electric & Gas Shared	The Electric and Gas Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber-security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Electric and Gas Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2024-01-01	2024-12-31	-1.00	-	121,946		-	-	-	-	-	-	-	46,204	-	-	-	28,240	17,119	845	-
152	2024	Application Currency-Operational Technology-Capital	Software(Intangible)	Electric & Gas Shared	The Operational Technology initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor-supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber-security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology applications value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2024-01-01	2024-12-31	-1.00	216,081	73,199		65,581	-	-	15,457	49,268	148	125	402	27,084	-	-	-	26,990	-	93	-
153	2024	Application Currency-Operational Technology-O&M	Software(Intangible)	Electric & Gas Shared	The Operational Technology initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber-security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology applications value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2024-01-01	2024-12-31	-1.00	-	179,301		-	-	-	-	-	-	-	67,935	-	-	-	67,618	33	484	-
154	2024	30% ROM Adjustment - Electric & Gas Shared	Software(Intangible)	Electric & Gas Shared	This is for the 20% ROM Adjustment for IT projects.							(16,196)	(14,147)	-	(17,537)	-	-	(3,692)	-	-	-	-	-	-	-
155	2024	Application Currency-TEOS-O&M	Software(Intangible)	Electric & Gas Shared	The TEOS initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the TEOS adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the TEOS are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2024-01-01	2024-12-31	-1.00	-	249,193		-	-	-	-	-	-	-	94,417	-	-	-	84,711	9,524	182	-
156	2024	Enhancements -Operations-Capital	Software(Intangible)	Electric & Gas Shared	The Operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Operations Portfolio is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	200,998	3,188		61,008	(8,324)	-	60,271	478	-	4,582	1,179	-	-	-	-	1,179	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHB-5)
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Witness: SHBaker
Date: December 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	RERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
157	2024	Enhancements -Operations-O&M	Software(intangible)	Electric & Gas Shared	The Operations Initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the Operations Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	-	248,133		-	-	-	-	-	-	-	94,015	-	285	-	52,344	39,625	1,761	-
158	2024	Enhancements -TEOS-Capital	Software(intangible)	Electric & Gas Shared	The TEOS initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in the TEOS Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for TEOS. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	67,468	100,000		20,476	-	-	17,490	-	126	2,861	37,000	-	-	12,184	24,296	520	-
159	2024	Field Contractor Work Management Technology Enablement	Software(intangible)	Electric & Gas Shared	The project provides the ability to electronically manage contractor work and increases accuracy and timeliness of information processing for field work deliverables. This project additionally will create new opportunities to measure and optimize field work process supporting customer on-time delivery goals. Contractor field employees use manual, paper-based processes and generic communication technologies (phone, radio, email, collaboration sites) to perform work for the Company. Due to the manual nature, inaccuracy, and delay of information processing there are negative impacts to the availability and accuracy of work status. This limits the opportunity to measure and optimize field work processes that support customer on-time delivery and other goals. The project will add value by: (1) improving on-time delivery of customer work by providing electronic work order information to contractors; (2) improving customer satisfaction through efficiency in scheduling work and reporting on the progress electronically; (3) increasing safety by tracking work and contractor data provided by information from the last known location of the contractor; (4) improving material management; (5) making it easier to renew emergent work for contracts to balance workloads and meet customer commitments; and (6) enabling real-time updates to work order information, increasing data accuracy and reducing invoice reconciliation time. The project scope includes: (1) identifying requirements for a Bring Your Own Device (BYOD) field contractor work management technology solution and process; (2) developing, configuring, and testing interfaces, software, and solutions for the solution; (3) implementing the solution and process for the following work groups: Electric High Voltage Distribution (HVD), Electric Low-Voltage Distribution (LVD), Mutual Assistance, Forestry, Gas Distribution, Gas Code Compliance, and Substation Operations Construction Metrics; (4) updating the following dependent contract types to support BYOD field contractor work management: zone, specific skill, ancillary, electric storm, and mutual assistance; and (5) training field contractors on the new technology and processes. The alternatives considered included: (1) Continue with the current paper-based process. This alternative was not selected because this approach does not allow for the timely, data-driven work management metrics required to improve service to customers. (2) Use the current Company mobile application. This alternative was not selected because the solution is not expected to receive long-term investments by the vendor and the mobile application would require more upfront investment than the proposed option. (3) Use a 3rd party platform specifically designed for contractor work management. This alternative would not be able to leverage the benefits and integrations with the existing platform and would require additional new integrations. (4) Provide Company-funded field devices to contractors. This alternative was not selected because the investment in hardware, management of on-board repairs of boarding of devices to contractors, and training and device management is cost-prohibitive and introduces a risk of the loss of or misuse of information security and corporate assets. Leveraging the existing field work management solution was chosen because it uses existing well-developed functionality while leveraging cloud-based, BYOD-capable tiles to move short-term and long-term contractors from paper process to the established, standard work management system.	2021-05-24	2024-12-31	-0.90	2,168,316	624,732		545,508	-	110,206	164,392	239,188	5,040	26,678	63,996	11,921	1,076	41,552	8,712	527	207
160	2024	Field Mapping and Graphics	Software(intangible)	Electric & Gas Shared	This project will implement a solution for the mobile field mapping and data collection that can search and view facility map data, view work order designs, and create work order as-built construction drawings in the field. This software technology increases process efficiency, personal tasking/field graphics functionality, reducing IT complexity and reducing unit increasing adoption in the field through ease of use. In addition, it allows the Company to move to a supported application platform and retire the unsupported ArcPad solution. The current mapping and graphics application was implemented in 2002 and is no longer sold or supported in any capacity, and the custom solutions developed for the application cannot be changed. Due to the impact and accuracy of the GIS landbase (streets, political boundaries, etc.), the outdated electric maps that are referencing that data causes the maps to be unreadable which cause a safety issue. Additionally, field employees have considerable challenges when attempting to use the software due to its dowess, an aged interface, and dated processes. The project will add value by: (1) providing more accurate geospatial data, including facility map data, pre-construction designs, and as-built construction drawings; (2) consolidating daily tasks into a more simplified experience; (3) eliminating the process waste from duplicating asset data in two systems; (4) establishing the adoption of the Geographic Information System (GIS) standard; and (5) making mapping and graphics data available on field devices. The project scope includes: (1) installing a new mobile field mapping and graphics application; (2) creating the ability to search and view the facility map data in GIS format along with the ability to search by address; (3) viewing pre-constructed work order designs in a new GIS format; and (4) creating as-built construction drawings in GIS format for completed work orders. Four alternatives were evaluated and three were determined not viable for the project: (1) Continue maintaining the current ArcPad application. This option was not selected because the Company is no longer able to maintain the ArcPad application to mitigate issues if the application crashes/critical defects. Total failure of the application could invert field crews back to paper-based facility maps, risking safety using static, outdated data, or requiring the creation of as-built construction drawings on paper documents. (2) Use the Adobe or Snagit application for creating as-built construction drawings. This option was not selected because field users would have to use one solution for facility maps and use rudimentary drawing tool like Adobe or Snagit for creating as-built construction drawings. This option was also not selected because it introduces additional steps due to the complexity and customization needed to integrate the applications. (3) Build a custom Mapping and Graphics solution. This option was not selected as existing industry solutions are available at a much lower cost with much less risk. (4) Implementing the new field mapping and graphics software was selected as this option will consolidate field graphics functionality into one efficient process and provide a current, supported solution	2020-11-30	2025-08-25	-0.72	4,400,537	70,897		238,081	-	-	140,637	77,999	2,397	12,048	5,806	-	-	-	5,806	-	-	-
161	2024	Field Network Director	Software(intangible)	Electric & Gas Shared	Prior period adjustment.							8,190	-	(27,191)	-	27,036	-	8,190	-	-	-	-	-	-	-
162	2024	Oblsoft PI Historian Upgrade 2020	Software(intangible)	Electric & Gas Shared	Prior period adjustment.							168	193	-	-	-	-	-	-	-	-	-	-	-	-
163	2024	Product Family Enhancements-Electric & Gas Shared-Capital	Software(intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Electric and Gas operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	1,374,484	183,697		417,136	-	-	245,366	159,068	3,451	9,277	67,968	-	-	1,888	66,058	22	-
164	2024	Product Family Enhancements-Electric & Gas Shared-O&M	Software(intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Electric and Gas operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	-	37,775		-	-	-	-	-	-	-	14,313	-	-	7,330	6,579	404	-
165	2024	Spatial Asset Management	Software(intangible)	Electric & Gas Shared	This initiative will implement SAP's Spatial Asset Management module. It will allow users to view assets, outfit actions, and orders geospatially using map. The module will allow us to create and maintain asset maintenance tasks for each segment of our gas and electric distribution network (linear assets) We will create linear assets as technical objects (such as functional locations and equipment) and create linear data. We will enable creation of maintenance plans for these technical objects which result in notifications, maintenance orders, and measurement documents. We will enable monitoring the condition of our linear assets, identify where there is damage or a defect, and manage all types of maintenance tasks (planned, unplanned, and preventative). Current Consumer Energy lacks spatial visualization and spatial awareness of work and assets impacting requirements for first time quality and inspecting the ability to plan, bundle and execute nearby work. The lack of a linear asset management capability affects the full work management value stream resulting in overproduction of asset maintenance activity such as assessments, surveys, and inspections. This project creates value for the company by: 1) providing capability in SAP to view assets, notifications, and work orders on a map, 2) providing location awareness in SAP for assets and work, 3) establishing linear asset management capability in SAP for gas and electric delivery networks, 4) enabling end-to-end map-based workflows. The scope of this project encompasses implementation in SAP of the Spatial Asset Management module. Alternatives considered include: 1) A Cloud-based individual asset integration between GIS and SAP. This alternative was not selected as it proves ineffective in addressing needs of the end-to-end work management value stream while increasing the technical footprint of customization. There are also performance concerns with cloud to on-prem integrations. 2) We'd group certain approaches to viewing work on a map. This alternative was not selected as it does not support extended operations the enterprise requirements call for. 3) Do nothing. This alternative was not selected as this would delay realizing costs and inefficiencies in gas and electric work management. 4) The alternative to implement the Spatial Asset Management module in SAP was chosen as it expands use of a core technology investment, supports current investment in our work management value stream, and is compatible with our GIS technology.	2023-12-04	2025-11-30	-1.00	3,158,109	206,194	ROM	276,878	70,737	-	187,684	-	-	18,458	36,702	-	-	25,950	10,752	-	-
166	2024	Work Management Scheduling Analytics and Reporting	Software(intangible)	Electric & Gas Shared	The project will implement a solution to optimize the key components of the Distribution Planning and Scheduling functions including forecasting, work order intake, resource identification, work schedule creation, work resolution preparation and associated work order analytics. The Distribution Planning, Scheduling and Administrative Support & Financial Services (Work Plan Strategy) teams are utilizing manually intensive work methods, systems and forecasting models. These inefficiencies impact the creation of work plans, task prediction capacity planning, and reduce productivity of operational partners. The project will add value by providing: (1) streamlined process to test for workload review and preparatory analysis, leading to increased focus on work-level priority, execution of work and a reduction of human touch; (2) increased accuracy in crew work schedules, leading to improved customer satisfaction and on-time delivery of customer-requested work, system integrity work, and gas compliance requirements; (3) reduced manual scheduling steps, reporting and analysis of data associated with work management processes and systems; thereby minimizing the risk of human error hours spent developing and updating crew work sheets; and (4) improved forecasting accuracy that results in greater transparency into the weekly schedule and associated work plan. The project scope includes: (1) implement a solution to facilitate the review of work orders from various engineering organizations, allowing for streamlined check-in of work orders; (2) implement a scheduling tool that utilizes predictive modelling and advanced analytics and streamlines daily schedule modifications; (3) enhance integration with the Area applications to bring in employee capacity and availability information; (4) integrate with SAP to retrieve work order data and manage record keeping requirements; (5) enhance integration with Field Service Suite (FSS) for quicker access to MISO 045 information and work order assignments; and (6) implement associated analytics and reporting. Three primary alternatives were considered for the project: (1) Automating manual data movement across excel and current systems through Robotic Process Automation. This option was not chosen because it will not create new efficiencies and will not provide data and insights into whether the schedule supports operating priorities and metrics, financial scenarios, first time completion of work, and daily goals; (2) Integrating an off-the-shelf planning and scheduling system. This option is not preferred due to associated up-front and long-term costs; and (3) Implementing a hybrid of an off-the-shelf planning component with custom built scheduling functions. This is the preferred option to provide a more cost-effective and targeted fit for the organization.	2022-01-26	2024-11-20	-0.69	2,283,004	176,667		159,638	-	-	135,974	13,714	970	2,970	22,005	22,005	-	-	-	-	-	-
167	**SUBTOTAL**	**2024 Electric & Gas Shared**										**1,943,245**	**213,875**	**98,818**	**994,862**	**530,064**	**12,185**	**91,712**	**705,271**	**74,150**	**1,076**	**184,716**	**189,682**	**4,189**	**207**
168	2024	Application Currency Gas-O&M	Software(intangible)	Gas	The Gas Engineering and Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Gas Engineering and Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational impacts of performing the upgrade, and ability to defer until next cycle. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; (5) testing the upgraded software; and (5) updating documentation related to the integration changes. Application within the Gas Engineering and Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) having increased support costs, and (4) possibly requiring additional support from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2024-01-01	2025-12-31	-1.00	-	225,321		-	-	-	-	-	-	-	205,321	-	-	-	222,778	1,902	642	-
169	2024	Corrosion Control Modernization	Software(intangible)	Gas	Prior period adjustment.							2,959	196,708	(87,301)	-	(148,400)	-	1,993	-	-	-	-	-	-	-
170	2024	Gas Leak Asset and Work Management	Software(intangible)	Gas	The project will implement functionality to automate gas leak compliance tasks and track all gas leak activity in the Gas Geographic Information System (GIS), creating a single system of record for gas leaks data, and providing a spatial display of leak data to improve leak management visibility. The gas leak process utilizes two systems to complete work and monitor gas leak compliance: SAP and Inspection Manager. Gas leak information is manually transferred between SAP and Inspection Manager and vice versa by compliance technicians. An internal audit identified 38 (18 leak orders, resulting in a 63% defect rate, with inconsistent information recorded between SAP and Inspection Manager. Lack of quality control to help ensure accurate leak information across systems may inhibit management's ability to effectively monitor gas leaks and could result in leaks not being re-classified or repaired in a timely manner. This has regulatory compliance and safety impacts such as missed compliance dates which may result in fines and increased public safety risk resulting from untimely or missed leak repairs. The project provides value to both the Company and customers, including: (1) improving productivity and field waste in accuracy; (2) enabling near-real-time reporting and automated metric reporting on open leak backlog; (3) creating one system of record for all leak assets in GIS; (4) implementing quality improvements for scheduling and routing of leak crews; (5) reducing risk of future audit findings or non-compliance resulting from duplicate open leak orders; (6) optimizing resource allocation for gas service post-system by eliminating manual posting of leak repairs into GIS; (7) optimizing resource allocation for the gas compliance team by eliminating the posting of leak repairs in Inspect on Manager; and (8) streamlining the leak survey workflow to improve the human struggle caused by use of paper maps and manual processes for leak order tracking. The scope of this project includes: (1) design and implementation of an API integration between the asset systems and the work management system to create, update, and manage leak maintenance, repair, and emergent orders and inspection schedules through the Enterprise Service Bus (ESB) or similar; (2) configuration of new SAP and Service Suite work order completion forms required to support new work processes; (3) updating the business intelligence dataset to support reporting; (4) reconfiguring workflows in Inspection Manager to capture all leak data from GIS; (5) design and implement a solution to replace the use of paper maps in the leak survey process; (6) implementing a workflow to communicate first time and repeated customer contacts for a given leak; (7) implementing an open leak order geospatial map of all open leak orders, utilized across office and field technology; (8) creating a system indicator that flags duplicate leak orders at the same location; and (9) implementing functionality to provide visibility through a list/map of all open leaks orders within a specified radius. Five alternatives were considered for the project: (1) Implement a Quality Assurance/Quality Control (QA/QC) process to ensure data is consistent between both SAP and Inspection Manager. This alternative was not selected because it requires an increase in labor costs for manual reporting and data checks. In addition, as demonstrated by the audit, manual processes, even manual QA/QC processes, are subject to human error, and each error creates safety and noncompliance risk. (2) Implement a Robotic Process Automation (RPA) to sync data. This solution was explored but is not viable because the base leak processes are too complex. (3) Implement a new GIS-based compliance solution that can be integrated with SAP. This alternative is too costly, given recent investment in the current Inspection Manager solution. (4) Defer project implementation. The alternative selected is to implement this project now, rather than later, as a result of recent gas leak related audit findings. (5) Implement functionality to automate gas leak compliance tasks and track all gas leak activity in the GIS. This alternative was selected because it leverages existing solutions in a new way, optimizing resources and technology investment. The use of Circuit technology was not considered due to the enhanced functionality being added to systems and applications that are already on premises.	2023-08-24	2024-12-27	-1.00	50,000	6,225	ROM	-	-	-	-	-	-	-	769	-	-	760	-	9	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHB-5)
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Date: December 2024

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	SPEND YEAR	PROJECT NAME	RERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALIZED FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
171	2024	Gas SCADA Software Solution	Software(intangible)	Gas	The Gas Supervisory Control And Data Acquisition (SCADA) software solution project will replace the current Gas SCADA Software with a more standardized software package enabling the Company to more efficiently meet Federal and MPSC requirements. The current Gas SCADA software solution was originally implemented in 2000 and was based on the gas system requirements at that time. While the solution has been maintained since its implementation, the Company's gas system has outgrown the current capabilities. As the solution ages, there is increased effort required to address obsolete application and database software architecture, and enhancements to the system are limited. To address the capability gaps, custom middleware and integrations have been developed where tech exists mean maintenance and support. This environment adds complexity and cost to solution upgrades and troubleshooting issues. The current Gas SCADA solution will limit the ability to invest in digital solutions for increased system health monitoring and preventative maintenance capabilities due to the complexity to integrate these future capabilities within. The project will add value by: (1) reducing risk of non-compliance by improving the ability to document and follow State and Federal requirements, improving customer safety; (2) improving efficiency and reliability when performing routine software upgrades, because a standard out-of-the-box software has less risk of breaking during upgrades, as gaps exist from custom code added software; (3) reducing maintenance costs due to fewer individual software programs and less custom code; (4) improving Gas Control management capabilities that support the Federal and MPSC requirements for gas pipeline and Gas Distribution operations; (5) improving reliability by using proven gas industry standard and software with configuration features, rather than a fully custom end system that has the possibility of being impacted by the next version update; (6) purchasing standard, out-of-the-box software that meets a high percentage of requirements and avoids multiple custom applications and specially coded programs to achieve results; and (7) providing a basis for capturing data required for use in computer-based preventative maintenance programs and more predictive technologies. In addition, implementing industry-specific software helps the collective gas industry as it moves to leverage the vendor development of future version enhancements, which adds more value to gas industry users. The comprehensive Gas SCADA system is used to monitor and control the operating conditions of the transmission and distribution gas systems. The Gas SCADA System includes remote terminal units (RTUs), field devices (i.e. valves, meters, cathodic), and computers running SCADA software. This scope covers the Gas SCADA software solution only. The project scope includes the following: (1) significant planning, including consulting assistance, to define the implementation strategy for the effort, given the magnitude of the technology effort; (2) selection and implementation of a new Gas SCADA software solution; (3) planning of a phased rollout of new hardware and software; and (4) retirement and decommission of the legacy gas SCADA solution and equipment once the new system is fully tested and operational. Alternatives considered include: (1) continue to maintain the current solution, at the risk of increasing reliability issue that result in controlling and monitoring the Company's gas system; (2) invest in enhancing the existing SCADA software solution which would introduce additional custom development and more specialized functions that may not be supported in future vendor releases; and (3) replace the solution with a gas SCADA software solution that meets requirements to support the Natural Gas Delivery Plan. Alternative three has been selected to ensure sustainability for this critical solution. The current legacy system is operating at well beyond its original design specifications, so the potential points of failure are not fully known or understood. If the SCADA project is not completed, the legacy system could become unstable and Impact Gas Control's ability to operate and monitor real-time system conditions, maintain safe operations, and compliance with regulatory requirements. It could also impact the ability to commission new facilities which require remote monitoring or control or cause the need for 24/7 manual field monitoring of certain facilities.	2022-04-18	2025-12-31	-0.97	18,018,040	2,205,237		6,022,548	555,511	855,365	1,194,638	4,957,908	23,030	441,113	460,517	113,779	170,909	191,534		184	4,111
172	2024	Gas Storage Probabilistic Risk Model	Software(intangible)	Gas	The Gas Storage Probabilistic Risk Model project will implement a risk analysis model for comprehensive predictive risk analysis and modeling on gas storage wells. The current Gas Storage model is a relative risk model that requires risk to differ from not impact information using qualitative data and ordinal scales to produce a risk ranking. In simple terms, the relative risk model is not capable of creating a statistically significant result. The risk assessment used in the current model provides a ranking for likelihood, consequence, and risk that is relevant only in comparison to other rankings. While the outputs provide a sense of relative risk when comparing one well to another, the current risk model does not provide anything qualitative that relates to the failure of wells. Also, the current transmission model does not meet the requirements of the MPSC, as indicated in a letter of noncompliance (dated January 15, 2019), and risk ranking for storage systems has historically followed transmission rule-making. Lastly, the current model introduces risk in PHMSA findings as a non-probabilistic model. Completion of this project will provide value to both the Company and its customers. Each party will benefit from safety improvements and risk mitigation through statistically based risk modeling that leads to more informed will improvement projects and improved targeted plug and abandonment projects. Implementing probabilistic risk modelling supports the changes planned for in the Company's Natural Gas Delivery Plan (NGDP), including the Company Gas Management Safety Systems (GMS). It GMS incorporates the Company's plan to implement the American Petroleum Institute (API) Recommended Practice 1173 (Pipeline Safety Management Systems). Additionally, the implementation of a probabilistic risk model will: (1) calculate quantitative risk scores that include measures of probability, frequency, or expected loss of events, and (2) configure multiple data sources, to make advanced statistical calculations for interacting threats, both of which allow the Company to make more informed financial and strategic decisions based on improved quality inputs and mitigate the risk of PHMSA findings. The probabilistic model will rank the wells in risk-associated dollars making it easier to interpret risk results for the purpose of making business decisions. Furthermore, the Pipeline and Hazardous Material Safety Administration (PHMSA) has identified the probabilistic risk model as a potential best practice for storage operators over other risk models (PHMSA Pipeline Risk Modeling white paper, dated May 5, 2016), so the project adds value by aligning with industry best practices. The project scope encompasses the implementation of a probabilistic risk model for gas storage wells. The project will: (1) install and configure risk model; (2) configure multiple data sources; and (3) diesel operators and dashboards. Alternatives considered include: (1) continue the use of the relative risk model, but invest in substantial effort to continually manually managing data inputs and quality checks; (2) implement a custom, Excel-based probabilistic risk model through a consulting effort; (3) implement an on-premise probabilistic risk model, and (4) implement a cloud-based model. The first alternative was not selected because although the manual effort is possible, it is becoming increasingly difficult to complete as the model utilizes more data sources that need to be annually updated and validated. The second alternative was not selected because although the effort minimizes the IT cost of the project, the model may limit the creation of secondary data sources, leading to multiple sources of truth. The on-premise solutions analyzed are not mature and have not been widely tested with transmission operators, so alternative three was not selected. The fourth alternative of implementing the cloud-based probabilistic risk model was chosen because it is the most cost-efficient long-term implementation approach, providing commercials, off-the-shelf capabilities, industry-proven technology, and an ongoing vendor support and improvement roadmap.	2023-04-14	2024-12-24	-1.00	1,577,860	145,522		619,958	-	-	30,711	555,985	319	32,942	10,158	-	-	-	10,000	-	158
173	2024	Gas T&D Historian	Software(intangible)	Gas	The Gas Transmission and Distribution (T&D) Historian project will replace the current historian for Gas T&D, eDNA (a traditional Supervisory Control and Data Acquisition (SCADA) historian product), and migrate to the standard OSIsoft PI enterprise historian system. The PI system is a suite of software products that are used to collect, store, view, analyze, and share operational data with systems and an adjunct matter experts. The historian for Gas Transmission and Distribution resides on a decades old platform and is not the Company's historian standard. Data access is cumbersome, requires multiple tools to access it, and does not provide for the storing, analysis or visualization of operational data in a timely manner with appropriate change management control. With the implementation of smart meters, the Company standardized on the more robust OSIsoft PI historian which is used for: (1) Renewable Generation; (2) Electric Transmission & Distribution; and, (3) Smart Energy. The Gas T&D historian has yet to be migrated to OSIsoft PI, and the eDNA gas data has limited accessibility and usability in its current state and is no longer supported by the vendor. In addition, maintaining the two platforms along with the new system requires duplicate resources and skills. This project will create a more accessible and centralized data source with better controls that can be leveraged as the system of record. The project will add value for both Gas Engineering and Gas Operations organizations within the Company by: (1) informing decision-making based on real-time data; (2) improving real-time situational awareness of Operators personnel for information that does not need to be monitored by Gas Control; (3) improving the ability to respond to abnormal situations that do not required immediate intervention through that direct communication to Operations personnel; (4) providing information for the development of proactive analytics to reduce potential catastrophic events; (5) streamlining data access through visualization and analytics; and (6) reducing the waste of using multiple interfaces to interpret data. From an IT perspective, consolidating to one standard historian platform will result in savings in hardware, software, maintenance, resources and training. This scope of this project includes: (1) migrate the eDNA Gas T&D historian, a traditional SCADA historian, and migrate to the enterprise Historian, OSIsoft PI; (2) develop analytics, visualization and reporting capabilities to support tracking of metrics and making operational decisions; (3) migrate the decades-old MKS mooth Access-based functionality Gas Reports solution and (4) retiring the legacy Gas T&D eDNA system hardware and software). An alternative considered for the project was to upgrade eDNA Gas Historian to the latest version. This option was not selected because it requires a significant investment, and does not meet analytics, reporting, usability and access ability needs as well as the software owner has announced the 1 unsafe, for this software. Furthermore, the Company standard for historians is OSIsoft PI and maintaining two platforms results in redundant efforts in training, support personnel and technology. The option to replace eDNA with the Company standard OSIsoft PI historian was well as extend to eliminate duplicate training, support personnel, and technology, and to leverage the more robust data analytics capabilities in the OSIsoft PI tool set. Currently the plan is to implement the Gas T&D Historian with the Gas SCADA Software Solution to eliminate the need to have duplicate historians within the Gas SCADA Software Solution is being implemented. If this project is not completed, an interruption of our operational data reporting capabilities could occur and could result in a no-compliance and could potentially interrupt certain wholesale accounting and billing functions.	2024-02-19	2025-12-15	-0.87	1,496,412	241,715		732,796	446,250	160,500	102,849	-	-	43,197	17,015	-	-	16,570	-	445	-
174	2024	Product Family Enhancements-Gas-Capital	Software(intangible)	Gas	The Gas Engineering and Operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Gas Engineering and Operations is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experiences; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software applications/investments for Gas Engineering and Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering and Operations, Operations Performance, Operations and Finance Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	427,727	88,193		427,727	-	-	170,848	217,029	16,525	23,325	88,193	-	-	20,440	65,470	2,283	-
175	2024	Product Family Enhancements-Gas-O&M	Software(intangible)	Gas	The Gas Engineering and Operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements in Gas Engineering and Operations is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experiences; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software applications/investments for Gas Engineering and Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering and Operations, Operations Performance, Operations and Finance Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	-	1,839		-	-	-	-	-	-	-	1,839	-	-	-	1,749	90	-
176	**SUBTOTAL**	**2024 Gas**										**9,811,021**	**1,198,469**	**948,543**	**1,495,066**	**5,182,519**	**39,894**	**548,571**	**823,812**	**113,779**	**170,909**	**452,082**	**79,121**	**3,653**	**4,269**
177	2024	800 MHz Modernization	Network	IT Digital Foundation	Prior period adjustment.							(118,586)				(101,586)			187	-	-	187			
178	2024	ARP-Local Area Network	Network	IT Digital Foundation	This project will upgrade the Company's entire LAN and a significant portion of the Wireless Local Area Network (WLAN). At some Company locations, LAN equipment has been in service since 2011. If the LAN/WLAN hardware and software is not routinely refreshed, the Company will lose the manufacturer support needed for equipment bug fixes, security vulnerability patches, and enhancements. In addition, aging equipment cannot accommodate the increasing demand for wireless devices necessary to perform day-to-day operations that rely on wireless-enabled devices, such as rugged field devices, cell phones, barcode scanners, tablets, and other mobile devices. As equipment ages, it is at risk of higher failure rates, which increase the risk of unplanned outages. In the event of unplanned outage, business areas would not be able to access services on the corporate network including email, SAP, internet, and phones. The project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor supported, thereby ensuring support for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; (6) increasing user productivity through a higher performing wireless network, which increases the productivity and efficiency of office and field employees serving customers; and (7) improving support for wireless Internet Protocol (IP) phones, Internet of Things (IoT) and field devices. The project's scope includes: (1) refreshing the LAN equipment and software across all Company sites; (2) identifying the required features for the new equipment; (3) implementing the new equipment according to industry best practices; (4) replacing wireless network with upgraded infrastructure and verifying wireless coverage is as expected; and (5) collecting wireless survey data for all Company locations in order to design improved wireless network coverage. The alternative considered was to continue operating on the existing platform past the vendor's end-of-support date. The vendor support period ended in May of 2021, and paying for extended support is not an option offered by the vendor. The risk inherent in not refreshing the platform is a lack of support, including access to the latest features and security updates, and bug fixes. The Company chose the option to refresh the latest hardware and software available, following a five-year refresh cycle.	2024-01-01	2024-12-31	-1.00	4,189,732	85,523		1,139,131	160,822	874,609	208,725	190,301	7,536	77,157	31,643	-	-	2,216	12,698	16,484	246	-
179	2024	ARP-Radio	Network	IT Digital Foundation	This project will refresh hardware to include; 800MHz Radios and infrastructure, cellular modems, plant radios and systems, cellular amplification devices and vehicle repeaters in service trucks. This equipment supports mission critical voice and data communications for plant and field service personnel and dispatch personnel. 800MHz radios are upgraded on a 10-year lifecycle basis. Plant radio systems are upgraded on a scheduled 7-year lifecycle basis. Cellular modems are refreshed on a 5-year lifecycle basis. Amplification systems are refreshed on a 10-year lifecycle. Vehicle consoles are typically retired with the vehicle but are salvaged for reuse in new vehicles when possible. 800MHz, mobile, and portable radios, Plant radio systems, and Cellular modems support core business functions, life safety as mandated, and rapid response for restoration of customer service and critical infrastructure. Company radio systems must be refreshed on a scheduled basis or risk exceeding life expectancy and failing. The refresh of these subscriber units in a proactive manner is critical to providing service to customers. If these units are not refreshed, the increased risk of unit failure would result in interruptions to timely and concise communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, which directly affects life safety. This project creates value for customers and the Company by: (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk workspaces by replacing equipment with units that contain internally safe batteries; (5) supporting continuous improvement as it is highly replacing equipment that is capable of capturing audio recordings; and (6) remaining in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure. The project scope consists of: (1) scheduled replacement of radios and modems and consoles; and (2) installing additional radios modems and console assets to satisfy growth requirements; and (3) scheduled replacement of out of date cellular and radio boosters. The alternatives considered included: (1) Replace the existing units with new units from other radio and modem vendors and (2) purchase new radio subscriber units from existing manufacturers. Option 2 was not selected because the Company now uses a standards-based radio system allowing for multiple radio manufacturer options. Option 1 was selected to allow for a competitive bidding process that will provide the most cost-effective radio that will meet the needs of users.	2024-01-01	2024-12-31	-1.00	1,335,332	154,940		619,480	-	677,124	(109,961)	48,118	1,760	2,347	57,328	-	-	53,924	1,560	1,744	99	-
180	2024	Application Currency-IT/Digital Foundation-Application Platforms-Capital	New Computers / Hardware	IT/Digital Foundation	The Application Platforms initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor-supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber-security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility issues. This project is delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, potential impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Application Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the additional upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increase in number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2024-01-01	2024-12-31	-1.00	92,400	141,101		38,048	-	-	28,043	-	-	-	52,207	-	-	52,127	-	80	-
181	2024	ARP-Collaboration	New Computers / Hardware	IT Digital Foundation	This project will replace the Company's obsolete or out of date audio, visual, telephony and other communication collaborative tools and equipment. When Collaboration Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value by: (1) ensuring that the Company's audio, visual, telephony, and other communications systems are stable and reliable; and (2) enabling the Company to leverage a new telephone systems that have reached end of mainstream manufacturer support. The project scope consists of: (1) annually replacing aging collaboration assets; and (2) installing new collaboration assets to account for evolving business requirements. The following alternatives were considered: (1) refresh visual assets and a portion of the audio assets; (2) refresh a portion of the audio assets only; and (3) refresh visual assets only. These alternatives were not chosen due to the risk inherent with a partial replacement of assets, which include: (1) a reduced supply of equivalent replacement Avaya parts that are no longer be produced; and (2) an erosion of the knowledge held by employees on skill sets and assets.	2024-01-01	2024-12-31	-1.00	1,231,853	208,340		336,938	-	254,377	11,223	67,648	1,178	22,592	77,086	-	-	8,879	4,796	22,796	32	40,583
182	2024	ARP-Field Device Asset Management (FDAM)	New Computers / Hardware	IT Digital Foundation	This project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failure, security patches, and software compatibility. When Field Device Assets are to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with Security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular four-year refresh cycle. This project creates value for the Company by: (1) improving stability and availability of business critical applications by proactively replacing field devices prior to increasing hardware failures; and (2) allowing field workers to complete their job tasks. The project scope consists of: replacing field device assets according to the four-year refresh cycle. The alternatives considered were to: (1) extend the replacement cycle from four years to five years for field devices; and (2) use outdated equipment. The Company did not choose these options because: (1) there would be an increase risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the assets that need refreshing in future years based on the number of devices that were not replaced during the four-year refresh cycle; and (4) it could cause an inability to apply security patches. Based on India Hydata, waiting longer than the five-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle to alleviate these concerns.	2024-01-01	2024-12-31	-1.00	3,043,872	5,350		1,139,985	-	1,307,786	10,146	14,489	1,441	2,973	1,980	-	-	1,980	-	-	-	-
183	2024	ARP-Operational Technology Support Gas	New Computers / Hardware	IT Digital Foundation	The ARP- OT Support Gas project will replace dated end to date servers on a rotating 5 year refresh schedule. When OT Assets that are used to support customer interactions and ensure the stability of technology for business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with Security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value by maintaining the currency of the Company's IT Infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical gas infrastructure. The program scope consists of: 1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements. The alternatives considered include: (1) continue to operate hardware beyond a five to seven-year refresh cycle or (2) refresh hardware based on a five to seven-year refresh cycle along with evaluating the health of the asset and evaluating business needs. The alternative to operate hardware beyond a five to seven-year refresh cycle was not selected due to the risk that these hardware components failures would cause system reliability and safety for customers, as vendors do not provide extended support after seven years. The Company chose the alternative to refresh this hardware based on a five to seven-year refresh cycle along with evaluating the health of the asset and evaluating business needs to reduce the risk of impacting critical infrastructure that supports systems such as Gas SCADA and Gas Compression control systems.	2024-01-01	2024-12-31	-1.00	1,033,227	19,800		1,033,227	47,957	980,660	39,640	9,218	1,518	4,180	19,800	19,800	-	-	-	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
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Witness: SHBaker
Date: December 2024

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	SPEND YEAR	PROJECT NAME	RERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION OF O&M SPEND FOR APPICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
184	2024	ARP-Printer Asset Management (PAM)	New Computers / Hardware	IT Digital Foundation	This project will replace and install select printers, plotters, and multi-function printing devices based on printer replacement assessments and a five-year refresh cycle. Printer service and usage history is evaluated and a determination is made if a printer can be repurposed instead of ordering a new one. When Printer Assets used to support custo mer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with firmware and security updates. The Company is at risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improving the dependability of these printer devices for employees; (2) averting increased costs due to hardware repairs; and (3) ensuring compatibility with enterprise print applications. The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle. The alternatives considered for the project included prolonging refresh cycles from three to seven years as well as running the assets to failure. The selection of a five-year cycle was deemed to be the best solution since anything less than five years would increase the likelihood of unneeded expense for replacement of devices that were still in good operating condition. Anything greater than five years was assessed monthly to ensure it is not run-to-failure, including running the asset to failure, resulting in additional expenses for maintenance of the equipment and down time, negatively affecting employee productivity. The Company was also the printer fleet based on years of active service, service history, printer usage data, and the number of users within a facility. Based on these factors, the Company ther determines, repurposes, leaves in place, or refreshes the printers.	2024-01-01	2024-12-31	-1.00	1,037,279	5,000		316,816	-	101,353	8,989	2,138	599	1,474	1,850	-	-	1,850	-	-	-
185	2024	ARP-Server and Storage	New Computers / Hardware	IT Digital Foundation	This project will replace or augment server and storage infrastructure for the Company. When Server and Storage Hardware Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company is at risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improved stability and availability of business-critical applications by proactively replacing server and storage hardware assets prior to the likelihood of increasing hardware failures; and (2) ensuring that adequate resources are available to support application demands after five to seven years of actual use. The scope of the program encompasses: (1) replacement of server and storage hardware assets; and (2) installation of additional new computers and storage capacity to account for evolving business requirements. The alternatives considered were to purchase extended maintenance, new some of these assets to the cloud with the Digital-Hybrid Cloud and Data Center Migration project, or to replace the assets on the current cycle. The option to purchase extended maintenance was not selected because full support could not be offered after seven years, and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital Hybrid Cloud and Data Center Migration project while refreshing the remainder using the five- to seven-year cycle as it is the most cost-effective option. If the Digital-Hybrid Cloud and Data Center Migration project is not approved as part of this rate case, the Company plans to continue to refresh these critical technologies at the current level based on a five- to seven-year refresh cycle to mitigate the risks of failure.	2024-01-01	2024-12-31	-1.00	774,113	112,720		236,948	1,248	200,494	14,999	12,285	447	5,380	41,706	-	8,737	20,345	11,438	1,057	130
186	2024	ARP-Workstation Asset Management (WAM)	New Computers / Hardware	IT Digital Foundation	This project will replace and install new desktops, laptops, and tablets on a five-year refresh cycle based on industry standards, hardware failures, security patches, and software compatibility. Monitors will be replaced every eight years based on Company data related to its total failure rates. When Workstation Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company is at risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing business partners to complete their job tasks. The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources. The alternatives considered were to: (1) extend the replacement cycle from four years to five years for all desktops and laptops; (2) extend the replacement cycle only on desktops from four years to five years; and (3) use outdated equipment. The Company did not select these options because (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) I would increase the ARP in future years based on the number of devices that were not replaced during the four-year refresh cycle; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle for desktops, laptops, and tablets; and an eight-year cycle for monitors to alleviate these concerns.	2024-01-01	2024-12-31	-1.00	5,916,948	28,244		1,778,794	-	1,712,808	79,353	3,238	1,656	(1,281)	10,450	-	3,921	-	2,857	159	3,514
187	2024	Data Center 2.0	New Computers / Hardware	IT Digital Foundation	Prior period adjustment.				2	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-
188	2024	Digital-Hybrid Cloud and Data Center Migration	New Computers / Hardware	IT Digital Foundation	This project will optimize data center assets and asset replacement project purchases by migrating or retiring applications out of existing Company and co-location data centers into cloud services, reducing operational costs for running IT services and leveraging increased capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services. The technology currently deployed in the Company's data centers meets many customers' needs today. However, the pace of digital transformation is increasing rapidly, and requirements for applications are evolving faster than the technology in the Company's data centers can respond in a cost-effective manner. The data center constraints lead to longer implementation times, missing capabilities, or reduced functionality in the applications that the Company can deploy. This project will create value by ensuring the Company's technology requirements are met through a comprehensive and cost-effective combination of data centers and public cloud services. Specifically, by migrating applications to cloud services, the project will: (1) reduce capacity, hardware maintenance, and security device costs at the co-location data center; (2) reduce hardware maintenance and security device costs at the production data center; (3) enable the ability to scale infrastructure quickly up or down without costly up-front hardware purchases; (4) reduce application risk through cost-effective, scalable infrastructure redundancy and availability; (5) reduce ongoing server and storage asset replacement costs; (6) reduce ongoing networking equipment replacement costs; (7) reduce operational support costs; and (8) enable the use of a vast array of cloud services to support Company applications. The project scope includes: (1) prompt right-sized migration of co-location data center to become the primary data center for on-premise IT services; (2) demoting the Company's production data center to the disaster recovery data center for on-premise IT services; (3) analyzing applications for migration to cloud or retirement; (4) migrating applications from on-premise to cloud; (5) transforming applications to use cost-effective cloud services; (6) altering network architecture and deploying less infrastructure to allow each location (on-premise or in cloud) to function independently; (7) deploying cloud and on-premise cost management tools (spend processes; (8) simplifying and optimizing backup and disaster recovery resources and processes using cloud services; (9) implementing additional automation for application deployment and management; (10) changing the operations model for support of cloud-based applications; (11) educating and increasing the skills of IT and other employees in leveraging public cloud services; and (12) transforming IT to become the broker of cloud services for the Company. Alternatives considered included (1) migrating to public cloud services faster. This alternative was not chosen because the Company's ability to absorb new technology investments the Company has already made in data center equipment would prevent a faster move from being efficient and effective, introducing additional financial risk; (2) migrating to public cloud services slower or not at all. This alternative was not selected because delaying public cloud services and capabilities coupled with requiring an extension of the life of existing data center equipment creates increased financial and operational risk; and (3) contracting with an outside vendor to provide cloud services to run applications for the Company. This alternative was not selected because industry information shows the option as not yet cost effective or not providing a maturity level that the Company would be able to easily consume with limited in-house experience and expertise in public cloud. The alternative to migrate to a hybrid cloud and data center model was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.	2023-02-01	2025-12-30	0.15	6,876,180	5,887,409		706,430	32,937	(61,302)	236,542	410,599	23,014	42,621	369,497	72,120	-	62,898	125,385	9,093	-
189	2024	SAP HANA Database Migration	New Computers / Hardware	IT Digital Foundation	In preparation for SAP's planned end of support for its Business Suite product in 2027, the Company will migrate its existing SAP databases from Oracle to SAP HANA in advance of the required move to SAP HANA. The Company's SAP applications currently run on either Oracle's relational database management system as their underlying database technology. SAP has informed its customers that its legacy Business Suite (aka ECC) product will end in 2027, along with support for all non-SAP database platforms. SAP has also informed customers that the future direction for their enterprise solution is S/4HANA, a solution built explicitly for their HANA database platform. To prepare for these upcoming events, the company will migrate all of its SAP databases off of Oracle and onto SAP HANA. This project has the purpose/benefit for the company's eventual shift to SAP's HANA-based solutions by: (1) proactively migrating SAP databases to a database technology that is fully supported by SAP beyond 2027; and (2) mitigating the risk of a complete loss of support for the current Oracle database technology in 2027. Project scope includes: (1) procurement of HANA software licensing to cover all migrated SAP applications; (2) data migration for all SAP applications from the Oracle database to SAP HANA; and (3) implementation of new application support policies, procedures and tools required to manage the newly migrated SAP HANA applications. Given SAP's announcement regarding the end of support for its ECC product in 2027, all customers running SAP on database software other than HANA will also lose support for their associated database software in 2027. SAP is offering no other options for databases other than HANA beyond 2027. While there is no alternative to the HANA database for SAP going forward, the Company has considered multiple options: (1) Perform a direct migration from SAP Business Suite on Oracle to S4/HANA. A direct migration to S4/HANA brings greater operational risk to the Company as both the underlying database technology and the SAP application's functionality would change simultaneously, so this alternative was not selected. (2) Remain on the current SAP Business Suite product but competitively bid support services to a third-party provider instead of SAP. This alternative was not selected because moving to a third-party support model forces the Company to remain on outdated SAP software and eliminates any possibility of benefitting from new business functionality provided by S4/HANA. It will also require the Company to accept significant risk due to the fact that SAP security patches and upgrades will not be available upon termination of the SAP maintenance agreement. (3) Migrate to SAP's Software as a Service (SaaS) implementation of S4/HANA. This alternative was not selected because an S4/HANA SaaS migration is a much more disruptive option as the Company's business processes must be adjusted to accommodate functionality differences between ECC and S4/HANA. The risk of negative business impact is significantly greater than simply changing the underlying database technology. The selected alternative to migrate the SAP databases to HANA prior to implementing S4/HANA gives the Company several years to solidify its HANA database infrastructure before introducing the substantial business process change required with S4/HANA.	2023-04-24	2025-12-31	-0.72	6,491,044	1,352,658		732,349	115,904	-	77,497	462,216	19,207	57,485	381,640	-	-	46,938	226,170	8,532	-
190	2024	2010 SharePoint Platform Replacement	Software(intangible)	IT Digital Foundation	Prior period adjustment.														34						34
191	2024	Application Currency-EPS-O&M	Software(intangible)	IT Digital Foundation	The EPS (formerly IA3) initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the EPS adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrades these applications encompasses: (1) upgrading the application software; (2) assessing new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes. Applications within the EPS are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying timing of the individual upgrades is considered based on (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) ongoing increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2024-01-01	2024-12-31	-1.00	-	216,793		-	-	-	-	-	-	-	82,141	-	-	53,465	26,493	2,183	-
192	2024	Application Currency-IT/Digital Foundation-Application Platforms-O&M	Software(intangible)	IT/Digital Foundation	The Application Platforms initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Application Platforms area are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) ongoing increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2024-01-01	2024-12-31	-1.00	-	51,521		-	-	-	-	-	-	-	19,521	-	-	19,208	-	313	-
193	2024	AnyWay Secure Transport 2024 Upgrade	Software(intangible)	IT Digital Foundation	Anway Secure Transport is the Company multi-protocol Managed File Transfer (MFT) gateway for securing, managing, and tracking data file flow for our business partners and external vendors. File impacting billing, HR, Supply Chain, Finance, Alternate Energy Programs, Front Office, Back Office, Device Management, Outage Management and Business Reporting functions utilize these services. This project will update the platform to the current software version, enabling cost savings potential enhancements while retaining data security and platform supportability. As Anway Secure Transport is the public-facing managed file transfer gateway, maintaining platform version integrity is critical to ensuring it remains secure and supportable in the event of a cyber attack, outage or other critical incident. A prolonged outage or incident, for any reason, compromises the ability of the Company to perform mission-critical business transactions in finance, operations and direct customer support. Upgrading this application also gives the Company the opportunity to properly scale Secure Transport and take advantage of the growing demand for additional, cost-saving features of the tool, such as managing internal Electronic Data Interchange transactions. The value this project brings Consumers Energy and its customers includes: (1) Addressing known problems and limitations of the current software and hardware platforms. (2) Ensuring continued secure, scalable, and critical data transmission services as running through Anway as mission critical functioning. (3) Creating the capacity to methodically merge/streamline internal and external data file transfer services to eliminate waste. (4) Merging/streamlining the company data file transfer services reducing cyber-attack vectors and creates a more easily maintained and monitored security model. The scope of this project include: (1) Upgrading the application and database to the current release and supported version. (2) Refreshing the underlying application infrastructure by upgrading to the latest operating system and hardware platforms. (3) Enable and test expanded Electronic Data Interchange (EDI) functionality. Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because the Anway Secure Transport platform handles critical Company financial, HR and operational transactions--the risk associated with problems stemming from an outdated and unsupported version is too high. Nor would the waste elimination benefits of using the upgraded Anway platforms start considerably ($?) for 36+ months. (2) Replacing the platform. The estimated project costs and timetable for replacing the business functions currently performed by the existing Anway Secure Transport platform would be extensive, and operationally, it is not well suited for a cloud or hybrid cloud solution. In addition to significant platform, application, implementation and functional testing costs, replacing it would require extensive coordination and testing with all of the internal and external account holders, taking upwards of one calendar year. (3) Upgrading the platform. This provides the Company the most cost-effective alternative, balancing costs, known risks, and even growing business capacity and productivity.	2024-02-27	2024-12-20	-1.00	-	476,892	ROM	-	-	-	-	-	-	-	95,802	25	-	7,699	87,140	938	-
194	2024	Cloud Virtual Desktop	Software(intangible)	IT Digital Foundation	Prior period adjustment.				-	-	-	-	-	-	-	-	-	-	485	-	-	456	-	30	-
195	2024	Digital-Cloud Data and Analytics Platform	Software(intangible)	IT/Digital Foundation	This project will provide Artificial Intelligence (AI) and analytics in the cloud across the business to uncover new paths to value, faster, allowing the organization to make better decisions and enable delivery across the NiSOF, Electric Grid integration, customer programs, and other business needs. The project will additionally establish data governance roles and responsibilities, process es, and implement to ols to support best practices across the enterprise. Consumers Energy faces several challenges in its ongoing data modernization journey, which include: (1) legacy data platforms operations; (2) long lead times for data exploration and identification of data assets; (3) lack of data ownership and quality; (4) limited data governance best practices across data ownership, access control & security; and (5) heavy dependence on IT for business intelligence reporting and analytics. The project will add value by providing data to support business needs by: (1) optimizing data platform operations costs with workflow based platform infrastructure deployment using repre-built modules and templates; (2) reducing data operations build complexity and data engineering costs through automation; (3) improving data quality and governance that leads to reduced costs of data provisioning, data duplication, and improved data accuracy; (4) streamlining data access requests, management, and governance to reduce risk and support efficiency; and (5) increasing the speed to deliver new data and data capabilities, improving productivity, and improving access to data. This projects is an enabler for business areas to use these capabilities to build analytic models for asset and labor optimization that is anticipated to more than offset the project costs. The project scope includes: (1) developing and modernizing the analytics platform in the cloud to allow Consumers Energy to implement new use cases leveraging simplified infrastructure deployments and operations, (2) building data management capabilities, centric catalog, access, and data flow; (3) developing data ordering workflows and data access management controls; (4) prioritization and new datasets; (5) simplifying infrastructure configuration; (6) automating deployment process es; (7) enabling data governance tools and processes. Alternatives considered include: (1) Address current pain points in existing on-premise and cloud analytical platforms. This alternative was not selected because the existing platforms requires new investments in licensing and infrastructure, delivery for new capabilities cannot keep pace with demand, still requires investment to address legacy system technical obsolescence, and business areas would not realize asset and labor optimizations. (2) Continue to build new data pipelines in the existing on-premise and cloud analytics platforms. This alternative was not selected because it would not address the current pain points in the existing on-premise and cloud analytics platforms, limiting the Company's ability to have required data and analytics capabilities to improve processes and realize asset and labor optimizations. (3) Implement a new data and analytics platform in the cloud. This alternative was selected because it provides improved analytics capabilities, faster access to data that is critical to improve business process, and reduces technical obsolescence.	2023-04-17	2024-12-27	-1.00	12,263,186	1,683,500		2,707,575	133,290	-	439,752	2,030,640	21,283	82,607	456,341	204,100	-	81,016	163,494	5,900	1,741
196	2024	Enhancements-IT-Capital	Software(intangible)	IT Digital Foundation	The IT Initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete routine activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are not the projects normally reviewed annually, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	39,925	-		12,137	65	-	4,231	-	68	7,753	-	-	-	-	-	-	-
197	2024	Enhancements-IT-O&M	Software(intangible)	IT Digital Foundation	The IT Initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are not the projects normally reviewed annually, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	-	3,610		-	-	-	-	-	-	-	1,368	-	-	-	1,282	85	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

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Date: December 2024

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	SPEND YEAR	PROJECT NAME	RERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
198	2024	Enterprise Print - Scan Suite	Software(intangible)	IT Digital Foundation	The project is intent is to upgrade the current Enterprise Print and Capture suite for improved data security and integration for the workforce home business partner. The company currently maintains a print and capture suite that will have support ending in 2025. Only high-level security patches will be available after this date. The company maintains a fleet of servers that are scheduled to be upgraded. The current print and capture suite is not compatible with the targeted server operating systems. The lack of internal resources require the company to continue to absorb increased costs to contract administrative personal. This project maintains cost savings achieved by eliminating waste full print jobs and further enables a productive, and flexible workforce for business partners working remotely. This project also ensures that the latest data transmission security requirements of are met by the solution. The project scope includes: (1) upgrading the current suite to the latest version, (2) consolidating the amount of print servers in the environment; (3) training for company personal to administer the suite; (4) converting all workflows from the current system; (5) implementing remediation for security vulnerability risk; (6) integrating device management with Enterprise Configuration Management Database (CMDB) for asset tracking and monitoring. Alternatives considered: (1) migrating to cloud services. This alternative was not chosen at this time due to maturity levels found with subscription services. This alternative was not selected as it would required new print and scanning specific to another print-scan product. (2) Print-scan products that were less costs. This alternative was not selected, due to fewer capabilities offered from the current product, which would introduced an inefficiencies in the current processes. (4) upgrade current product. This alternative was chosen due to low overall cost of not requiring new hardware, maturity of current product, and providing same level of capabilities required to support current processes.	2024-04-05	2024-12-31	-1.00	660,096	216,630		210,409	-	-	-	8,500	197,416	107	311	80,153	-	-	-	79,999	-	154	-
199	2024	Enterprise Service Bus Application 2020-2021 Upgrade	Software(intangible)	IT Digital Foundation	Prior period adjustment.							101	-	-	83	-	-	18	-	-	-	-	-	-	-
200	2024	Enterprise Service Bus Application 2024-2025 Upgrade	Software(intangible)	IT Digital Foundation	This project will upgrade and migrate the Business Works developer application to the next version. Newer ESB software versions offer improved integration with Rest/API services and applications. It is critical that this vital data tool or pathway be more scalable, secure, and capable of integrating to service-based environment. In addition, the messaging and event modules within the ESB are currently outside of their standard support windows. While it is possible to continue to get extended support by paying an estimated premium of approximately $80,000 annually, this is just temporary coverage and serves only to delay the need for an upgrade. The value this project provides the Company includes: (1) cost avoidance to avoid extensive payments for extend support purposes; (2)avoid technical debt exposure; (3) operational resiliency; and (4) improved administrative and operational efficiencies. The project scope includes implementing current version of all applications that are part of the ESB application, database versions and required database drivers. Alternatives considered included: (1) Accept the annual $80,000 extended maintenance as-is. Given the critical nature of this application, it is not recommended to lose mainstream support for any of the applications involved. Any sustained ESB product deficiency would impact many areas of the Company, such as billing, revenue collection, and remote meter management. The current implementation of the ESB platform was built with 5 years of growth in mind. This alternative was not chosen due to risk to Company operations, and the additional expense. (2) Replace the on-premise upgrade plan to implement a cloud-based solution. A cloud migration would also take longer to complete, which would put the Company at risk of falling outside of the current vendor support window for the products current version. (3) Upgrade the restricapplication. This option was selected because it best meets the Company needs for the near future by restoring vendor support for fixes and patches, and enables product scalability to the measure required of business capabilities.	2024-09-04	2025-11-21	-0.93	-	784,244	ROM	-	-	-	-	-	-	-	2,661	-	-	-	2,661	-	-	-
201	2024	IT Operations Management - Service Operations	Software(intangible)	IT Digital Foundation	This project will implement an application service mapping tool to effectively manage business-critical services through identification of infrastructure components and application interactions. This tool automates the mapping process to create a complete, up-to-date, and accurate record of the mapped application service in the Database. Application service mapping not only hand-in-hand with asset discovery, building on discovered infrastructure data to identify all the assets that support a service, and along with their service-specific relationships. As the IT systems steadily increase in complexity and evolve faster than the IT organization can respond to system issues in an optimized and cost-effective manner, the current configuration of the system does not provide the clarity needed in order to understand how the infrastructure interacts with the applications within the IT System. It supports and in order to respond to emergent IT incidents in the most rapid and cost-effective manner. This constraints can lead to lengthy response and implementation times; negligible or ineffective resolutions; reduced functionality; and elevated outage times in the infrastructure and applications in the system. This project will create value for the Company by mapping critical application services through discovery of the underlying infrastructure associated with application services and its relationship to parent business applications. Specifically, by creating application service maps, this project will: (1) increase visibility and understanding between Information Technology (IT) infrastructure and Configuration Items; (2) improve accuracy through real-time, automatically updated infrastructure and component changes; (3) reduce IT Subject Matter Experts time on emergent IT issues; (4) Utilize of IT Service Management processes; and (5) Reduce downtime by identifying dependencies and impact analysis. The project scope includes: (1) implementation of On-Premise application service maps which have significant business impact; (2) establishment of process roles needed to support service maps built. Alternatives considered included: (1) Choose an alternate IT Operations Management System with Cloud capabilities. This alternative was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain a similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. This alternative was not chosen as there would be a correlation gap between application services and the underlying infrastructure and would not address the ever-increasing resolution costs. (4) Develop and implement an on-premises service mapping and process solution. This alternative was chosen due to the value in the Information Technology (IT) Operations Management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can utilize the Configuration Management Database (CMDB) and work hand-in-hand with asset discovery	2023-10-01	2024-08-30	-1.00	3,012,243	699,524		60,745	-	-	1,134	41,980	710	16,941	24,369	-	-	171	23,711	486	-
202	2024	Nimbus Phase 5	Software(intangible)	IT Digital Foundation	Prior period adjustment.							(1,016)	(1,016)	-	-	-	-	-	-	-	-	-	-	-	-
203	2024	Operational Technology - Service Management Upgrade	Software(intangible)	IT Digital Foundation	This project will implement Operational Technology service management capabilities. Service management provides automated asset tracking, maintenance, and incident management for the assets. The Company' internal Audit team conducted an audit of the Operational Technology (OT) asset environment and identified significant gaps in the patch management program. The patch management operating model is decentralized, has limited and inconsistent standards, does not have a company-wide governance structure to monitor all business areas of the Company and lacks a complete and accurate asset inventory. Due to the lack of a complete asset inventory, as well as a significant number of gaps identified in the patch management governance, operating model, processes, and controls to manage all assets within the Company's environment, an unknown magnitude of risk exists that critical patches were not installed timely, which could create the potential for increased security vulnerabilities. The project provides value to the Company in three ways: 1.)Establishes a complete and accurate asset inventory; 2.) Creates a Company-wide governance structure with documented standards and processes to manage the assets and 3.) Defines a comprehensive patch management operating model with clearly defined roles and responsibilities. The project scope include: (1) the implementation of an asset management tool (2)the implementation of an incident management tool, (3) and the establishment of process roles needed to support the assets. Alternatives considered included: (1) Choose a Cloud based alternate asset management system. This option was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain a similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. Continue to manually track or not track Operational Technology (OT) Digital assets at the Company, which will not address the need to effectively track OT Digital assets and plan for their support. (4) Develop and implement an asset management and incident management tool and process. This alternative ultimately chosen has strengths in Information Technology's (IT) service management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can help bridge the gap between IT and OT, enable the Company to manage both types of assets through a single interface.	2023-10-01	2024-08-29	-1.00	892,455	192,305		49,747	-	-	11,271	22,908	1,035	14,532	16,246	-	-	(720)	16,919	47	-
204	2024	Product Family Enhancements-Application Platforms Services-Capital	Software(intangible)	IT/Digital Foundation	The IT Initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and funds to ability improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fees and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	708,412	230,308		215,008	-	2,312	197,971	7,889	1,668	5,164	85,214	-	-	85,109	-	105	-
205	2024	Product Family Enhancements-Application Platforms Services-O&M	Software(intangible)	IT Digital Foundation	The IT Initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and funds to ability improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fees and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	-	390,340		-	-	-	-	-	-	-	154,880	-	-	145,641	6,984	2,255	-
206	2024	Product Family Enhancements-IT/Digital Foundation-Capital	Software(intangible)	IT/Digital Foundation	The IT Initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and funds to ability improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fees and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	1,034,209	273,686		310,888	119	817	263,889	32,131	4,789	12,138	101,264	3,337	-	87,914	8,920	1,093	-
207	2024	Product Family Enhancements-IT/Digital Foundation-O&M	Software(intangible)	IT/Digital Foundation	The IT Initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives. The value of software enhancements that benefit the IT organization is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and funds to ability improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fees and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	-	356,630		-	-	-	-	-	-	-	155,124	-	-	113,260	20,582	1,283	-
208	2024	Public Key Infrastructure (PKI) Upgrade	Software(intangible)	IT Digital Foundation	Replace on-premise PKI to stay supported by the manufacturer. The existing PKI that is used to issue certificates to IT systems for secure communications needs to be upgraded to stay supported by the manufacturer. If the PKI is not maintained, in the event of a system failure the Company would not have support in recovering. All IT systems requiring secure communications via certificates would go offline within these days. Replace existing PKI with new PKI that is supported by the manufacturer. The project will build and configure the servers necessary to provide Public Key Infrastructure services, put in place physical token management for maintaining security, migrate certificates using said management to the new system and decommission the old systems. The Company has a limited scope security PKI on the Internet only. (1) The Company looked into expanding the service to include usage in the Company network but found the solution to not be economically viable. (2) The Company also looked at full cloud solutions, but it did not meet the security standards currently being used and implemented. (3) The Company looked at continuing extended support, however the continuing extended support is not available by the vendor. (4) The Company selected a hybrid solution of part cloud and part on-premise to meet all operational and security compliance requirements. The cgoal is unity to retain ownership of the keys on-premise prior to evaluating ownership through the cloud.	2023-10-02	2024-12-31	-1.00	1,818,198	423,977		419,226	43,022	141,083	98,695	161,578	466	14,432	96,921	(12,352)	68,374	34,447	5,990	462	-
209	2024	SAP Support Pack Upgrade 2023-2024	Software(intangible)	IT Digital Foundation	The SAP Support Pack Upgrade project is to maintain the currency levels of all SAP applications. This will ensure the applications are at version levels that are supported by SAP, have the latest patches and bug fixes, and provide cross-application compatibility for our business partners. To continue to maintain SAP application version currency, across all applications, the support packs released by SAP must be routinely applied. Within a maintaining application currency, the core business application is running on the SAP platform are at risk of losing vendor support, resulting in the inability to apply bug fixes and patches, including security patches, and maintain application interoperability and stability. The project will add value by: (1) maintaining supportability of SAP applications; (2) mitigating system security, stability and reliability risks by ensuring the applications are up-to-date with the most current patches and bug fixes released by SAP; and (3) ensuring ongoing cross-application cost capability. The scope of this project includes routine support pack upgrades to all SAP applications, which include: Enterprise Core Component (ECC), Customer Relationship Manager (CRM), Enterprise Portal, Process Orchestration (PO), Business Warehouse (BW), Business Objects (BOBJ), Data Services (DS), Governance, Risk and Compliance (GRC), Solution Manager, Data Quality Manager (DQM), Graphical User Interface (GUI), Single Sign On (SSO), System Landscape Directory (SLD) and other related SAP applications. Alternatives considered include: (1) Divide the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and to replexing them separately could lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) Migrate to SAP S/4HANA. This option was not selected at this time because it is part of the long-term digital plan and requires substantial planning and investment, (3) Retire the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimal cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.	2023-10-30	2024-10-31	-1.00	-	169,421		-	-	-	-	-	-	-	60,292	-	-	2,756	55,028	2,508	-
210	2024	Software Asset - Service Management Upgrade	Software(intangible)	IT Digital Foundation	This project will optimize the software asset management process by systematically monitor, assess and oversee software licenses and compliance using Software Asset Management Professional. The on-premises software asset management technology currently used in the Company lacks compatibility to automate license reclamation, cost optimization, and license forecasting. These software asset management constraints lead to the inability to optimize software license purchasing and effective license demand management. This project will create value by ensuring the Company's technology requirements are met through a comprehensive and cost-effective software asset management process and workflow. Specifically, by replacing the on-premise application, the project will: (1) streamline the software request workflow including license reclamation and software deployment; (2) help ensure compliance with software license agreements; (3) identify opportunities for license optimization leading to cost optimization; (4) mitigate risk related to software asset management; (5) optimize license forecasting and (6) increase asset visibility. The project scope includes: (1) the implementation of software asset management tools; (2) the establishment of process and process roles needed to support the assets; and (3) retirement of the on-premise software asset management tool. Alternatives considered included: (1) Choose an alternate Cloud based asset management system. This alternative was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain a similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. This alternative was not selected as the current Software Asset Management tool that lacks integration and automation and will not address optimizing and effective management of licenses and purchases. (4) Develop and implement an on-premises Software Asset Management solution. This alternative ultimately chosen has strengths in software as set management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can helps license compliance, optimization and automation.	2023-06-01	2024-08-15	-0.80	1,130,474	260,229		31,358	-	-	5,844	12,710	1,281	1,518	29,647	-	-	12,610	15,541	1,495	-
211	2024	Software Platform Refresh	Software(intangible)	IT Digital Foundation	The Software Platform Refresh project will upgrade server operating systems, hypervisors (virtual machine monitors), and databases to retain in low-cost vendor support. For systems that go beyond their normal manufacturer support ending, there will be increased support and maintenance fees of 20% to 100% above current support and maintenance depending on vendor. Completing this project will owes the organization to (1) avoid high support costs; (2) provide for system security and (3) stay current to promote seamless interoperability among servers, applications, and databases. Aging servers are more susceptible to security vulnerabilities and performance issues that ultimately could affect the business and customers. The project will add value for the Company by (1) and dispositions for special maintenance agreements required at the end of normal manufacturer support; (2) ensuring reliability and compliance with Information Security requirements; (3) improving data center environment stability; and (4) avoiding the need for high risk upgrades that cross multiple versions. The project scope includes: (1) upgrading operating systems and databases on servers that are near end of support with a given vendor; and (2) maintaining hypervisors at the current version for stability and performance. A funding options matrix was completed to review the potential alternatives. The alternatives identified were: (1) Complete the full scope of the solution for $1 million in order to eliminate the need for ongoing extended support; (2) Reduce the scale of the solution, which requires $1.6 million in ongoing extended support; (3) Reduce the scale of the solution even further, which requires $2.4 million in ongoing extended support; (4) Do not complete a software platform refresh, which requires $3.3 million in ongoing extended support. Alternative 1 was selected as the most cost effective solution to ensure ongoing system stability; seamless integration; and mitigation of cyber-security risks without the significant cost of extended support necessary for End of Life software systems.	2024-01-01	2024-12-31	-1.00	-	82,550		-	-	-	-	-	-	-	31,278	21,649	-	7,377	1,886	365	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHB-5)
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Witness: SHBaker
Date: December 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALIZED FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
212	2024	SolarWinds Performance Monitoring Expansion Upgrade	Software(intangible)	IT Digital Foundation	This project will develop an IT observability and monitoring solution that provides an aggregate view of IT system availability and performance. The current IT enterprise monitoring approach doesn't provide a comprehensive view of application and infrastructure health resulting in unplanned service interruptions, extended service interruptions, and system performance degradation. In addition, unplanned service interruptions have a negative impact on business partners ability to provide reliable services to utility customers. The SolarWinds Expansion project will allow IT to reduce the number of monitoring tools and consolidate end-to-end view of IT performance alerts to a single pane of glass. These actions will prevent major service interruptions, reduce Major Incident Mean Time to Restore (MTTR), improve IT system stability, and ultimately reduce O&M labor cost. This project scope includes : 1) Perform proof of value (POV) assessment for the following SolarWinds modules, Hybrid Cloud Observability (HCO), Database Performance Analytics (DPA)/ AppOptics/ Pingdom; 2) Transition applications monitored by AppDynamics to SolarWinds. 3.) Deploy and configure agent base infrastructure monitors for applications and infrastructure 4.) Retire AppDynamics. 5.) Transition critical applications not monitored by AppDynamics to SolarWinds. 6.) Create performance monitoring tools/dashboards for critical systems. 7.) Define monitoring templates for rapid deployment of new monitoring services. 8.) Training the Product/Platform Teams on use and management of SolarWinds. Several monitoring tools were considered to manage alerts and escalation on Consumers Energy IT application and infrastructure ecosystem. Other considerations included our ability to consolidate other monitoring tools into a single tool and reduce licensing and maintenance cost. Below are the alternatives that were considered: 1). Renew current licenses for both SolarWinds and AppDynamics with out achieving any savings or operational efficiencies. 2). Considered other vendors like Dynatrace to replace AppDynamics at a reduced cost for service, but initial deployment and annual cost would significantly increase regardless of service selected. In addition, the other vendors considered didn't have the capabilities to monitor both application and infrastructure which didn't allow for a consolidated approach to be adopted and/or reduction in licensing and ongoing maintenance cost. As a result, the other vendors considered were not an option. 3). In conclusion, SolarWinds was determined to be the most cost-effective approach because of the expanded capabilities offered through the following modules, Hybrid Cloud Observability (HCO)/ Database Performance Analytics (DPA)/ AppOptics/ Pingdom that meets the needs of IT to proactively monitor IT systems and retire tools with similar capabilities to reduce ongoing maintenance cost. Therefore, our decision is to move forward with deploying the expanded services offered by SolarWinds.	2023-03-27	2024-08-29	-0.49	1,766,608	336,026		1,135	-	-	979	-	-	217	1,422	300	-	685	363	73	-
213	2024	Tibco API Exchange Gateway Replacement	Software(intangible)	IT Digital Foundation	This project is looking to retire the API Exchange Gateway which the Tibco ESB and replace it with a new solution called Microsoft Self-Hosted Gateway. The API Exchange Gateway is used by the TIBCO ESB to integrate to external vendors, all new development will need to be done to integrate this solution. The Tibco API Exchange Gateway is anticipated to be sunset by the vendor, as they have already dropped all development of enhancements for the platform. This project creates value for the Company by: (1) Avoiding the risks of running an project no longer supported by the vendor (i.e. the Tibco Enterprise Service Bus API Exchange module), and (2) Enabling the Company the opportunity to move to a product that is more stable, secure, and usable. The project scope includes: (1) Conducting a RFP to procure a replacement product and review the architecture team to migrate the product. (2) Migrate all current work items to the new platform. (3) Conduct appropriate testing to ensure all Service Level Agreements are met. Alternatives considered include: (1) Evaluating the replacement of the current product with a new product that is not already in the Company environment. This alternative was not selected because it was did not be cost effective. (2) Keeping the current application as is. This alternative was not selected as the vendor for the current platform has stopped all development for his product. (3) Leveraging an existing solution already in the Company environment. This alternative was selected as it avoids multiple solutions with redundant capabilities and avoids costs for supporting and maintaining a second solution.	2023-01-03	2024-12-27	-1.00	899,876	122,603		278,133	-	-	189,672	15,298	1,159	66,997	45,363	-	-	23,565	20,506	1,293	-
214	SUBTOTAL	2024 IT/Digital Foundation							12,733,062	534,947	6,202,411	1,827,218	3,641,505	90,381	437,560	2,365,899	309,050	148,030	960,721	888,712	60,306	46,002
215	2024	ARP-Cyber Security	Network	Security	This project will develop an IT observability and monitoring solution that provides an aggregate view of IT system availability and performance. The current IT enterprise monitoring approach doesn't provide a comprehensive view of application and infrastructure health resulting in unplanned service interruptions, extended service interruptions, and system performance degradation. In addition, unplanned service interruptions have a negative impact on business partners ability to provide reliable services to utility customers. The SolarWinds Expansion project will allow IT to reduce the number of monitoring tools and consolidate end-to-end view of IT performance alerts to a single pane of glass. These actions will prevent major service interruptions, reduce Major Incident Mean Time to Restore (MTTR), improve IT system stability, and ultimately reduce O&M labor cost. This project scope includes : 1) Perform proof of value (POV) assessment for the following SolarWinds module, Hybrid Cloud Observability (HCO)/ Database Performance Analytics (DPA)/ AppOptics/ Pingdom; 2) Transition applications monitored by AppDynamics to SolarWinds. 3.) Deploy and configure agent base infrastructure monitors for applications and infrastructure 4.) Retire AppDynamics. 5.) Transition critical applications not monitored by AppDynamics to SolarWinds. 6.) Create performance monitoring tools/dashboards for critical systems. 7.) Define monitoring templates for rapid deployment of new monitoring services. 8.) Training the Product/Platform Teams on use and management of SolarWinds. Several monitoring tools were considered to manage alerts and escalation on Consumers Energy IT application and infrastructure ecosystem. Other considerations included our ability to consolidate other monitoring tools into a single tool and reduce licensing and maintenance cost. Below are the alternatives that were considered. 1). Renew current licenses for both SolarWinds and AppDynamics without achieving any savings or operational efficiencies. 2). Considered other vendors like Dynatrace to replace AppDynamics at a reduced cost for service, but initial deployment and annual cost would significantly increase regardless of service selected. In addition, the other vendors considered didn't have the capabilities to monitor both application and infrastructure which didn't allow for a consolidated approach to be adopted and/or reduction in licensing and ongoing maintenance cost. As a result, the other vendors considered were not an option. 3). In conclusion, SolarWinds was determined to be the most cost-effective approach because of the expanded capabilities offered through the following modules, Hybrid Cloud Observability (HCO)/ Database Performance Analytics (DPA)/ AppOptics/ Pingdom that meets the needs of IT to proactively monitor IT systems and retire tools with similar capabilities to reduce ongoing maintenance cost. Therefore, our decision is to move forward with deploying the expanded services offered by SolarWinds.	2024-01-01	2024-12-31	-1.00	420,000	25,000		217,139	93	898,182	15,437	842	115	1,799	9,250	-	-	4,118	5,132	-	-	-
216	2024	Pipeline SCADA Security	Network	Security	This project will implement major modifications to the Gas Supervisory Control and Data Acquisition (SCADA) environment to ensure compliance to American Petroleum Institute (API) 1164 standard. API 1164 is an MPSC regulatory requirement with most updates to the Gas Technical Standards. The project will implement IT, cyber security, and physical security equipment and the modifications necessary for regulatory compliance to API 1164. The MPSC requires the implementation of pipeline cyber security regulations pursuant to API 1164 on the Company natural gas pipeline system. The Company's Gas SCADA system is outdated and non-standardized, requiring significant modifications to be compliant with API 1164. Without the technology updates, the gas SCADA system is vulnerable to cyber attacks that potentially risk disrupting deliveries to customers. Interruptions in gas delivery and non-compliance to API 1164 mandated requirements could be subject to fines and penalties from the MPSC and other regulatory entities (i.e., the Transportation Security Administration). This project will add value to the Company by: (1) modernizing and standardizing the Gas SCADA network at the Company's gas compressor stations and storage fields; (2) mitigating cyber security vulnerabilities in the Gas SCADA network; (3) allowing the Company to fully comply with API 1164 requirements; and (4) fulfilling the commitment to the MPSC to provide a secure gas system that meets customer needs. The project scope includes updates for multiple gas SCADA-related locations, including eight gas compressor stations, two gas control rooms, two data centers, and multiple intelligent pipeline field devices. To establish compliance with API 1164, the project will: (1) design a holistic network architecture to implement both physical and technical changes; (2) implement physical enhancements to impacted facilities, such as additional doors on data rooms, and modified HVAC systems to provide necessary climate control for the SCADA equipment; (3) install additional security cameras and/or card readers necessary to control access to new and existing equipment; (4) complete technology upgrades requiring design, development, testing and implementation for the Gas SCADA network at each of the planned locations. Upgrades will consist of endpoint protection, identity and access management, vulnerability management, business continuity capabilities, cyber incident response, asset management, and so on mature test environments; and (5) implement additional security measures on field devices, including default credentials, secure communications, change management, and patching activities. As this is a regulatory compliance requirement, there are no alternatives to completing this project. Without the completion of this project, the Company could be subject to noncompliance fines and penalties from the MPSC.	2020-06-01	2024-10-28	-1.00	12,592,731	542,854		639,681	68,641	(76,988)	305,722	204,365	6,298	131,593	117,802	67,663	220	18,818	31,101	-	-
217	2024	TSA Critical Facility Structure	Network	Security	This project will implement enhanced security measures outlined by the Transportation Security Administration (TSA) for critical facilities sets in order to bring the locations up to enhanced status and avoid non-compliances. This project will increase the security and reliability of gas delivery to our customers while also meeting federal requirements. Pipeline facilities that are deemed critical set are required to apply enhanced security measures. Today, Consumers Energy currently has designated 4 locations as critical. However, based on the April 2021 update to the TSA Pipeline Security Guidelines, best on 5 Critical Facility Criteria), a significant number of our gas infrastructure that were not previously subject to evaluation will now fall into scope. As we continue to analyze the remainder of our gas assets, we believe an additional 1000 pipeline facilities (pipeline interconnections, metering and/or regulating stations, compressor stations, operational control facilities, main line valves, tank farms and terminals, etc.) may be deemed critical. Consumers Energy will be taking a phased implementation approach and will begin the process by implementing the enhanced security measures at the remainder of our compressor stations. Failure to update our sites will put us out of compliance with the updated guidelines. The objective of the project is to implement enhanced security measures outlined by the TSA for the following four critical assets: (1) Freedom Compressor, (2) Muskegon River Compressor, (3) Overisel Compressor, and (4) Northville Compressor. In order to bring these locations up to Enhanced status and avoid non-compliances. This project will increase the security and reliability of gas delivery to our customers while also meeting federal requirements. Enhanced Security measures that will need to be implemented include, but are not limited to: (1) access controls; (2) access invaders; (3) cameras; (4) video and audio programming; (5) fencing and barriers; (6) gates; (7) locks and key control; (8) fence intrusion (which may be accomplished with a new camera system); (9) subcontractor work for trenching, patches, etc.; (10) field lighting; (11) background investigations for personnel working at the site; (12) security equipment maintenance and testing; (13) security vulnerability assessments; (14) security communication plans; (15) personnel training; (16) security drills and exercises for the following locations. These activities will be performed at the following company locations: Overisel Freedom, Northville, Muskegon River. Alternatives are not available because this is a compliance mandate from the TSA.	2023-11-27	2025-12-28	-1.00	9,088,335	584,724		3,798,608	-	888,051	84,144	2,846,217	-	28,196	30,000	-	30,000	-	-	-	-
218	2024	ARP-Physical Security	New Computers / Hardware	Security	This project will enhance or replace physical security assets to provide improved visibility and incident resolution related to security concerns. The Company has several thousand physical security asset devices currently in use including security cameras, motion detectors, intrusion detection systems, and card access systems. Current limitations include the lack of integrated solutions for centralized management, situational awareness, real time monitoring, compliance with regulations and guidelines, and effective responses to emergencies and incidents. This could result in the increase of potential security vulnerabilities, associated penalties, and reputational damage. The value provided by completing the project is to: (1) maintain compliance with State and Federal Regulations; (2) reduce redundancies with less of a need for multiple cameras and reduced support in functionality; and (3) optimize overall system performance included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) security cameras for monitoring capabilities; and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detectors systems, and card access systems. Alternatives considered include: (1) not refreshing physical security assets, and (2) before-and-after enhancements to improve and standardize the business partner experience As part of the review process the alternative considered was using manual processes. This option was not chosen because it was deemed too costly and inefficient.	2024-01-01	2024-12-31	-1.00	1,551,703	29,934		470,942	-	899,408	1,767	269,146	16	605	11,076	-	-	11,022	-	53	-
219	2024	Radar Intrusion Detection	New Computers / Hardware	Security	Prior period adjustment.							(6,791)	-	(7,205)	-	419	-	-	-	-	-	-	-	-	-
220	2024	AccessNOW	Software(intangible)	Security	The Access show project will implement on-figurable identity, Access Management functionality and best practices, and will enforce compliance. Access NOW replaced the CAAR system enterprise wide in 2018Q4 with over 50,000 requests being made since product launch. However, Access NOW's manual process and lack of integration are leading to increased risk for human error and time spent on process set that can be automated. This project will add value by: (1) reduce human error and failure points through automation; (2) improving and standardizing the business partner experience; (3) centralize access management; (4) ensuring regulatory compliance; and (5) ensuring system stability and continuous improvement. The project scope includes implementing additional integrations to Active Directory domains that are not currently connected to the Access NOW application (ConsCorp.com, DNSC.com, emu.com, mpa.com energy.com, cpbpa. com energy.com) and integration to the Company's SAP systems) to allow for automation of SAP role access provisioning. In addition, the project scope includes: (1) design, configuration and testing of technical connectors; (2) completion of application support pack upgrades to the next version(s) to maintain system stability and to stay current with vendor releases; and (3) review and implement enhancements to improve and standardize the business partner experience As part of the review process the alternative considered was using manual processes. This option was not chosen because it was deemed too costly and inefficient.	2017-05-29	2022-10-31	-0.95	4,392,463	1,603,587		130,819	-	2,573	157,006	(31,998)	101	2,171	10,154	-	-	9,461	606	86	-
221	2024	Application Currency-Security Capital	Software(intangible)	Security	This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyber threats, per tect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Security portfolio adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; (4) allowing the Company to leverage new functionality available in the upgrades; (5) provides customer value through closing the gaps on vulnerabilities that can impact reliability; (7) provides a mechanism for proactive actions to stay ahead of evolving cyber threats. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on consideration that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) assessing any new functionality for value to the Company, (2) making necessary configuration changes, (3) testing the upgraded software, and (4) updating documentation related to the integration changes. Applications within the Security portfolio are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of these efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number or incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for the listed applications possible and fortifies the Company's ability to keep the large number of security applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2024-01-01	2024-12-31	-1.00	30,000	10,002		9,105	-	-	9,105	-	-	-	3,701	196	-	3,505	-	-	-
222	2024	Application Currency-Security O&M	Software(intangible)	Security	This project will utilize both O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrade The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyber threats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Security portfolio adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality; (4) addressing version interdependencies and compatibility between systems; and (5) allowing the Company to leverage new functionality available in the upgrades; (6) provides customer value through closing the gaps on vulnerabilities that can impact reliability; (7) provides a mechanism for proactive actions to stay ahead of evolving cyber threats. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on consideration that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Security portfolio are routinely evaluated to determine if upgrade efforts are necessary to maintain an appropriate level of currency and then prioritized accordingly. During that evaluation process, the alternative of delaying the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increase in the number of incidents; (3) paying increased support costs; and (4) prevention of employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of security applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2024-01-01	2024-12-31	-1.00	-	15,904		-	-	-	-	-	-	-	6,026	-	-	6,024	-	2	-
223	2024	Enhancements-Security Capital	Software(intangible)	Security	This initiative will use Capital funding to make enhancements to existing technology and to address requirements generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements in accordance with accounting rules. As business conditions improve and change, compliance requirements evolve, and new capabilities are needed, new requirements surface that call for smaller effort software application changes (enhancements). Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval and individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, limit the Company's ability to consistently meet objectives, and increase security risk. The value of technology enhancements in the Security Portfolio lies in: (1) enhancing security protections by funding engineering or unplanned cyber security activities resulting from audits, incidents, or a changing threat landscape; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage additional functionality available in the technology. The scope of technology application enhancements: (1) making necessary systems changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy, and compliance. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each business that routinely evaluates and prioritizes the work and assesses requests for value using categorical benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	-	11,814		-	-	-	-	-	-	-	4,371	-	-	-	4,371	-	-
224	2024	Enhancements-Security O&M	Software(intangible)	Security	This initiative will use O&M funding to make enhancements to existing technology and to address requests generated by changing business requirements. As business conditions improve and change, compliance requirements evolve, and new capabilities are needed, new requirements surface that call for smaller effort software application changes (enhancements). Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval and individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, limit the Company's ability to consistently meet objectives, and increase security risk. The value of technology enhancements in the Security Portfolio lies in: (1) enhancing security protections by funding engineering or unplanned cyber security activities resulting from audits, incidents, or a changing threat landscape; (2) lessening the number of incidents associated with outdated software; (3) increasing application stability, leading to fewer incidents due to outdated software; and (4) allowing the Company to leverage additional functionality available in the technology. While these small-work technology efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvement to existing technology investments for Security. The scope of technology applications encompasses: (1) making necessary systems changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each business that routinely evaluates and prioritizes the work and assesses requests for value using categorical benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2024-01-01	2024-12-31	-1.00	-	664,869		-	-	-	-	-	-	-	251,913	8,988	-	211,266	29,825	1,808	25
225	2024	Saviynt Enterprise Identity Governance and Access (EIGA) Implementation	Software(intangible)	Security	The project will implement Saviynt EIGA module, consolidate Identity Access Management (IAM) functionality into Saviynt, and retire the identity Manager application. By implementing the new solution, the Company will optimize IAM functionality, eliminate complexity, and reduce support costs. In addition, the project will integrate the OT network with an IAM solution that will allow for automated management of users and entitlements in the OT Active Directory domains and applications. The current version of Access show reached end of life in December 2022, with support also continued in January 2023. The application has numerous custom workflows and integrations, requiring professional services for ongoing use and changes. It lacks proper data analytics and reporting, posing risk such as inability to fix critical defects, software incompatibility, compliance issues, increased costs, and degraded performance. The Company uses multiple IAM tools, each performing specific functions, leading to numerous required interfaces and customizations. While beneficial for end users, these integrations increase the risk of system failure, higher support costs, multiple subscriptions, infrastructure and maintenance costs, and more expensive upgrade. The current solution utilizes SAP Hirtsteh file processes that introduce failure points, delays, and data integrity issues. Failures in these processes can prevent new or transferred employees from accessing necessary systems, leading to operational disruptions and potential compliance risks due to inappropriate access retention. This project provides value by: (1) Consolidating multiple IAM platforms through the implementation of the Saviynt Enterprise IGA Module, reducing complexity and support costs; (2) Decreasing complexity and enhancing efficiency by reducing interfaces between multiple identity tools; (3) Improving the end-user experience and reducing human struggle with access requests through a new, intuitive portal design; (4) minimizing custom code and focusing on configurations only by utilizing out-of-the-box functionality; and (5) Streamlining employee data processing with the implementation of an HR interface. The project scope includes: (1) Implementing the Saviynt EIGA module to consolidate IAM platforms; (2) Standardizing processes by removing customized code and using out-of-the-box functionality; (3) Replacing and improving access system (4)Addressing issues with aging applications, multiple IAM platforms, integration challenges, and antiquated HR processing. Alternatives considered include: (1) Implementing Net Iq as Access Now version 8.1.5 to ensure support through mid-2023; (2) Upgrading only the application to current supported versions, including the new web portal but will including new application function ality; (3) Remaining on current version that will be unsupported as of January 2023, requiring vendor professional services for any break / fix. Patches and enhancements may potentially introduce additional risk of version instability; (4) Implementing IAM functions in Saviynt platform to manage access requests, including Active Directory, SAP, SAP HR, disconnected systems, and existing API integrations. The alternative selected was implementing the new Saviynt system, eliminating Access Now software.	2023-11-27	2024-06-30	-1.00	5,913,132	710,912		930,609	433,752	-	135,349	299,998	123	61,393	74,085	63,370	-	10,620	91	4	-
226	2024	Security Analytics	Software(intangible)	Security	Prior period adjustment.														10			9			
227	SUBTOTAL	2024 Security							6,188,207	501,495	1,154,712	709,490	3,589,170	6,453	235,757	518,397	140,316	34,339	275,856	65,994	1,915	25
228	TOTAL	2024							33,046,466	2,636,935	8,404,483	5,591,974	13,697,882	169,399	1,346,192	5,709,237	665,490	354,358	2,323,145	2,048,676	71,057	50,504

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025, and 2026
Information Technology Department

REDACTED

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	RERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
229	2025	2025 Union Contract Changes	Software(Intangible)	Corporate	The 2025 Union Contract Changes project will implement SAP and other system changes required as a result of three collective bargaining agreements which will be renegotiated and ratified. Collective bargaining agreements expire every five years for Operating (Maintenance and Construction), Collective bargaining agreements expire every five years for ONEAC (Operating (Maintenance and Construction), CCC (Customer Contact Center) and Zeeland employees groups. For ONEAC, the current agreement ends June 1, 2025. CCC agreement ends on August 1, 2025. Zeeland agreement ends October 1, 2025. Technology changes are required to reflect these new agreements. Otherwise, employees in this union groups may not be paid appropriately or get correct benefits. Completion of this project will provide value to the Company and its customers through: (1) ease to elimination by making changes in the software for any pay and benefit changes as required by the new agreements; (2) defect reduction by adding process automation to otherwise manual processes including and recording work, premium, and absence time; and (3) improved employee engagement among the ONEAC, CCC, and Zeeland union employees. The scope of this project encompasses making any system changes required to support the new working agreement for the ONEAC, CCC, and Zeeland employees. Exact details will be finalized after the negotiation process is completed and contracts are approved. Three alternatives were considered for this project: (1) Make no system changes other the contracts are ratified. This option was not chosen because it exposes the Company to possible fines, disengaged employees, union grievances, significant manual processes leading to greater possibility of error, hiring additional staff to perform activities outlined in the agreements, and increased legal costs due to employee grievances. (2) Find other third-party software to support the changes required by the union agreements. This option was not chosen because it would require SAP integration along with additional software licensing and maintenance costs. (3) Make system changes to eliminate manual updating, comply with the working agreement language, support union employee engagement, and reduce grievance. Option (3) was chosen because it leverages current SAP technology, automates what would otherwise require manual processing, and is the least costly option	2025-04-01	2026-12-01	0.00	-	618,667		-	-	-	-	-	-	-	-	122,436	-	-	-	51,295	63,132	-	8,010	-
230	2025	Application Currency-Corporate-Capital	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technological landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber-security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Corporate Services adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) address ing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Corporate Services are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	57,350	5,350	ROM	18,033	-	15,715	1,571	-	97	629	1,991	-	-	1,860	-	130	-
231	2025	Application Currency-Corporate-O&M	Software(Intangible)	Corporate	The Corporate Services initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technological landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber-security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Corporate Services adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) address ing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Corporate Services are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	-	372,068	ROM	-	-	-	-	-	-	-	105,208	-	-	126,362	-	8,845	-
232	2025	Asset Accounting Tax Upgrade	Software(Intangible)	Corporate	The project will upgrade our current accounting asset management tax software to the SaaS version as required by the vendor or a replacement solution and implement additional new features, ensuring continued support of a critical Financial application, and providing new functionality. In 2026, standard vendor support ends for the current on-premise PowerTax software. Using vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. There are also larger costs to upgrade if the upgrades are further apart due to complexities to functions and too many versions exist at any one time. This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support; and (4) lowering costs with more frequent upgrades to reduce too many updates to and reduce the number of versions to be adopted. The project scope includes: (1) evaluating current vendor/product solution with market leaders; (2) upgrading the vendor's software from the current version to the newer version. Alternatives considered include: (1) Evaluate SAP options for fixed asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerTax, it would be more complex, costs more, and not provide all the required features. (2) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (3) Analyze and go to do all possibilities (4) wait until a future upgrade cycle. (5) Upgrade to the newest version of current solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrade, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.	2026-02-01	2026-11-01	-1.00	-	1,572,781	ROM	-	-	-	-	-	-	-	146,387	19,729	-	39,457	78,915	8,286	-
233	2025	Asset Accounting Upgrade 2025-2026	Software(Intangible)	Corporate	The project will upgrade our current accounting asset management software to the latest version as required by the vendor, ensuring continued support of a critical financial application. Standard vendor support will end for the current on-premise software on an undisclosed timeline. Using vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. There are also larger costs to upgrade if the upgrades are further apart due to complexities to functions and too many versions exist at any one time. This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support; and (4) lowering costs with more frequent upgrades to reduce too many updates to and reduce the number of versions to be adopted. The project scope includes: (1) evaluating current vendor/product solution with market leaders; (2) upgrading the vendor's software from the current version to the newer version. Alternatives considered include: (1) Evaluate SAP options for fixed asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerTax, it would be more complex, costs more, and not provide all the required features. (2) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (3) Analyze and go to do all possibilities (4) wait until a future upgrade cycle. (5) Upgrade to the newest version of current solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrade, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.	2025-02-01	2026-11-01	-1.00	-	682,561	ROM	-	-	-	-	-	-	-	371,652	-	-	59,186	-	162,466	-
234	2025	HR Support Pack and Business Software Inc Upgrade 2025	Software(Intangible)	Corporate	The HR Support Pack and BSI upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes. SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll. This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll. The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company. Alternatives considered include: (1) Not upgrading to the current support packs which results in noncompliance with financial rules and regulations and inaccurate payroll. (2) there is no economical do-ud solution, so this option was not entertained. (3) apply the appropriate support pack upgrades. Option (3) is the preferred option because it enables the company to comply with HR and tax changes, resulting in the ability to correctly calculate and distribute payroll.	2025-02-05	2025-12-31	0.00	-	983,661		-	-	-	-	-	-	-	367,457	28,764	-	38,668	201,075	16,782	72,168
235	2025	Product Family Enhancements-Corporate-Capital	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. A business process improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual level or here. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work activities and efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for the funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	3,848,634	552,239		1,209,636	-	-	780,283	12,578	68,072	348,699	205,471	-	-	183,553	8,475	13,442	-
236	2025	Product Family Enhancements-Corporate-O&M	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual level or here. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work activities and efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	555,559		-	-	-	-	-	-	-	206,723	-	-	193,199	-	13,524	-
237	2025	Talent Management Enablement	Software(Intangible)	Corporate	The project will deliver technology solutions to enable best-in-class Talent Management programs and processes that are critical to achieve the Company Significant technology improvements are required to transform Human Resources (HR) to develop the skills and capabilities necessary to achieve the Company This project will add value to the Company through technology that will enable: (1) fully functional integrated compensation modules; (2) a calculated and targeted talent development of critical skills necessary to deliver on the Company The scope will include: (1) implementation of each system/application; (2) integration with current systems, applications and processes as applicable; (3) retrofit current systems and applications to ensure a seamless end-to-end experience of HR processes; (4) delivery of mobile capabilities for in scope processes; (5) reporting and analytics dashboards and report insights for in scope processes. Three alternatives were considered for these Talent Management programs and processes: (1) Develop custom, internally built solutions that could meet most requirements. This alternative was not selected because a custom solution would result in higher overall costs, higher maintenance costs, fewer upgrades, and would not leverage industry best practices to ensure in-house delivery. (2) Select an on-premise software tool. This alternative was not selected because it requires internal maintenance, increased infrastructure costs, and would have less frequent upgrades which would hinder the Company's ability to ensure processes are evolving alongside industry trends and best practices. (3) Evaluate and select do-ud SaaS solution(s) which would have lower infrastructure costs, less internal maintenance than an on-premise solution, and would be built and evolved with upgrades based on industry best practices. Based on research, internal experience with success of best practice implementations, and vendor demonstrations, option three was selected.	2023-02-27	2025-12-19	-1.00	1,221,532	464,821	ROM	175,211	-	-	55,003	78,575	9,350	30,283	35,700	-	-	18,603	13,022	4,074	-
238	2025	30% ROM Adjustment - Corporate	Software(Intangible)	Corporate	This is for the 20% ROM Adjustment for IT projects.							(38,245)	-	(5,365)	(1,315)	(15,715)	(1,890)	(1,182)	-	-	-	-	-	-	-
239	**SUBTOTAL**	**2025 Corporate**							**1,562,604**			**1,237.5**		**625,143**	**75,452**	**75,480**	**19,438**	**1,433,023**	**48,493**	-	**312,184**	**266,619**	**235,359**	**72,168**
240	2025	Application Currency-Customer-O&M	Software(Intangible)	Customer	The Customer initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Customer digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to few er incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, and (2) updating documentation related to the integration changes. Applications within the Customer are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	-	10,456	ROM	-	-	-	-	-	-	-	3,800	-	-	3,551	-	249	-
241	2025	Customer Order Service Tracker	Software(Intangible)	Customer	Short cycle orders including gas emergencies and meter services account for many of the incoming customer inquiries to the contact centers. This project will implement a service order status tracker to provide transparency to customers and oversight to internal teams supporting utility service orders across Company service areas. The tracker will provide timely and accurate service order updates, creating a more robust customer experience for tracking service order status and location-based updates. Customers have limited visibility to when Company assigned crews will be on premise and what work will be completed. This is due to features missing within the Company's digital channel for accurate updates from dispatch, scheduling, and field crews. The lack of awareness drives calls into the call center, resulting in approximately 360,000 annual contact center call related to short cycle requests. Additionally, this lack of visibility increases truck rolls due to dispatchers being unaware of an open location and routes which can cause crews to be assigned when a location could have completed the work. This leads to overall customer dissatisfaction because of a lack of visibility to scheduled and ongoing short cycle work. Enabling a digital channel for communication regarding utility service orders will improve customer experience and reduce the waste of repetitive crew dispatching. This project will add value to the Company and its customers by: (1) providing transparency for customers on the timing and location of the associated crew completing utility short cycle service orders, (2) reducing calls to contact centers by customers seeking clarification regarding arrival times through visibility to scheduling time considerations, notifications, and updates to customers when crews are enroute, (3) improving crew success assignment by current location, which decreases wasted truck rolls time and enabling location services for active crews, (4) increasing visibility into the service person(s) completing the order by enabling crews to connect with customers through digital channels, and (5) improving customer experience for short cycle service orders by implementing a channel of choice for Company interactions. The scope for the project includes: (1) modifying the customer self-service portal to include features that support utility service order tracking, including the location of crews en-route, (2) providing location and mobile capabilities, (3) enhancing the existing crew arrival platform to allow real-time status updates that can be communicated to customers, (4) building custom-released services to updates internal portals in real-time, and (5) enabling text and email notifications to alert customers of service crews arrival times. Alternatives considered for this project include: (1) Deploy a mobile application to address utility service order tracking, (2) utilize a do-ud hosted solution from a third-party, (3) modify the existing customer portal to enable customers and the Company to track utility service orders and crews. Options one and two were not selected as the cost associated with deployment would greatly outweigh the benefits with all-inclusive internal improved customer experience. The third option was selected because it utilizes existing technologies, which reduces the implementation complexity and project cost and has faster value realization for the customer and the Company.	2025-01-10	2026-08-28	-1.00	4,021,500	1,186,250	ROM	798,198	-	-	212,153	282,800	34,652	228,700	309,009	-	-	83,715	111,620	13,673	-
242	2025	Energy Assistance Enhancements and Maintenance Annual Updates	Software(Intangible)	Customer	The Energy Assistance Enhancements and Maintenance Annual Updates project, formerly known as Consumers Affordable Resource for Energy (CARE) project, will implement software changes to offer energy assistance to low-income customers and streamline the process for the assistance agencies who use the assistance portal. This is accomplished through improved user interface and updates to SAP processes various requests. Upcoming modifications will be identified following an ongoing and annual review of requests, that includes criteria from the Department of Health and Human Services (DHHS) and Michigan Public Service Commission (MPSC) to prioritize the list of changes. Each grant year, DHHS and MPSC stipulate the criteria required for customers to enroll in the CARE program, how the Company and agencies will manage the enrollment process and track active CARE customers, and how they will administer the Michigan Energy Assistance Program (MEAP) benefits through bill credits and arrears forgiveness. The criteria changes significantly each year; therefore, the Energy Assistance Enhancement and Maintenance Annual Updates application requires modifications to meet the new requirements. If the regulatory requirements are not fulfilled, the Company is at risk of losing state Low Income Energy Assistance Fund (LEAF) funds to assist low-income customers with paying their energy bills, thereby increasing the customers risk of shutoff for non-payment. In addition, our energy assistance programs funds on with in all software platforms in the company which co nsistently need enhancements and updates. The project will provide the following value: (1) complete modifications to internal SAP application and Energy Portal to receive LEAF funding, which can be used to provide customers the bill credits and arrears forgiveness; (2) improve data within the assistance agencies portal, thereby making it easier to assist customers in need of LEAF funding; and (3) complete modifications to customer facing platforms. The project scope includes: (1) updating the enrollment and status process; (2) allowing for flat monthly bills; (3) improving reporting; (4) updating the arrears forgiveness plan; (5) satisfying additional regulatory requirements for the annual grant rule changes required by the Department of Health and Human Services and Michigan Public Service Commission; (6) updating CARE during process; and (7) updating the assistance portal (CEPAS) functionality to enhance Agency Self-Service. Alternatives considered include: (1) continue with current process. This alternative was not chosen because it was believed to loss of grant funding, thus decreasing or eliminating energy assistance dollars for customers; (2) transfer administration of Energy Assistance Programs to a third party organization. This alternative was not selected because it would remove ownership and visibility into the health of the program while increasing administrative costs; and (3) make annual updates to the application, which will allow agencies to easily enroll customers in assistance programs and allow placement of holds to stop or prolong credit active/pundi assistance decisions are granted. This option was selected since it provides long-term proactive energy assistance to customers and prevents loss of grant funds. Changes are required to internal systems such as SAP, a large internal system that supports broad areas of the business, and the Agency Portal, an internally developed web application, therefore a single cloud or third party alternative is not viable. Additionally, retiring the existing Agency Portal for a new application would increase costs beyond that of the routine upgrades.	2025-01-01	2025-12-31	0.00	-	332,623		-	-	-	-	-	-	-	123,769	-	-	105,821	9,851	8,097	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025, and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHS-5)
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Witness: SHBaker
Date: December 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
243	2025	Genesys Cloud Migration	Software(intangible)	Customer	The project will migrate the Company 's 2020 standard vendor support ends for the current on-premise software and extended support is not available from the vendor. Without vendor support, the application no longer receives security patches, bug fixes, or functionality support from the vendor, which creates security, stability, and reliability risk. With the upcoming end of standard support, the vendor is no longer offering feature enhancements to the current on-premise solution limiting the Company. This project will provide value to both the Company and its customers through: (1) reducing risk with its outdated stated hardware scalable to current usage needs; (2) reducing operating costs with vendor managed feature updates and maintenance provided without service disruption; (3) providing access to new and innovative capabilities to enhance customer service; and (4) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support. The project scope includes: (1) deploying the new PWS cloud-based solution in the vendor cloud environment; (2) installing a new internet circuit to directly connect the Company. Alternatives considered include: (1) Defer to later years. This alternative was not selected due to requiring upgrades of existing on-premise hardware, impeding our ability to take advantage of new features offered by the cloud solution, and reducing cost savings opportunities presented by moving to the cloud. (2) Deploy Genesys on-premise solution to new on-premise hardware. This alternative was not selected due cost associated with purchasing new hardware and does not address the security, stability, and reliability risk resulting from the vendor end of support for the on-premise software. (3) Select and migrate to a new vendor software. This alternative was not selected due to the complexity of our existing internal integrations between the Genesys platform and the Company's other internal systems. As a result, selecting a new system with a new vendor would make the switch cost prohibitive. (4) Migrate to the Genesys Cloud platform. This alternative was selected due to it building on the Company strategy of moving to cloud, reducing operating and maintenance costs, and reduces risk by ensuring consistent, seamless vendor support.	2024-07-02	2025-12-28	-0.80	-	8,008,452			-	-	-	-	-	-	-	32,354	-	-	-	17,756	8,384	6,215	-
244	2025	Product Family Enhancements-Customer-Capital	Software(intangible)	Customer	The Customer Initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software applications changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Application Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using a categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project forth is the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	7,710,995	900,958		2,428,586	-	-	1,157,996	657,113	77,042	531,414	318,847	-	-	-	272,675	18,392	27,780	-
245	2025	Product Family Enhancements-Customer-O&M	Software(intangible)	Customer	The Customer Initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Application Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using a categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project forth is the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	434,156		-	-	-	-	-	-	-	161,549	-	-	-	100,024	32,584	9,211	19,729
246	2025	Rate Change Maintenance	Software(intangible)	Customer	The Rates Change Maintenance project will modify SAP billing in accordance with pricing and rate change requirements. For the Company to continue to meet and comply with the Michigan Public Service Commission (MPSC) rate change requirements, there is a need to make gentle updates/modifications to the existing price and rate structures. These updates help ensure accuracy of billing and provide optimal rates for customers. The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing; (2) optimized rate configuration enabling rate changes to be made more efficiently; and (3) timely updates to Company applications that incorporate mandatory changes to the rate structure that include new surcharges, price changes, and energy efficiency programs. The scope of this project encompasses (1) implementation of annual or monthly (or both) electric and gas customer price changes, and rate structure changes as approved by the MSPC; and (2) optimizing the rate configuration in the billing system to implement the most efficient rate changes. An alternative considered for this effort was a fully dedicated offshore development model. The option ensured resources were readily available with a more cost-effective labor expense. This alternative was not chosen due to the risk of billing inaccuracies and customer complaints. These risks were deemed too high because of the complexity of the structure, new development, and the timing it was all take for testing of this model. Cloud is not an applicable option in this case as we are not replacing any software. The option to use onsite resources to plan, coordinate, and execute the rate changes was selected as it supports the Company's operation model for rate changes.	2025-01-01	2025-12-31	0.00	-	318,120		-	-	-	-	-	-	-	318,372	-	-	-	110,628	-	7,744	-
247	2025	SiteCore Primary Upgrade 2025	Software(intangible)	Customer	The project will refresh all components of the website hosting delivery, search, and analytics applications to add new features and improve search capabilities. Sitecore is the content management application for the consumers energy.com website, a channel many customers use for access rapid content information and bill payment. Sitecore is currently operating on version 10.3, which is due to end mainstream support at the end of 2025. If this occurs, there will be an increase in support and maintenance fees of 10% above the annual subscription spend in order to purchase extended support, security updates and fixes will only be made available if the extended support is purchased, and product support for errors or required hotfixes that may impact platform stability will not be available even if extended support is purchased. The project will add value to the Company by: (1) avoiding costs for extended maintenance agreements required at the end of mainstream support; (2) ensuring that the website retains the most up-to-date security patches; and (3) supporting the Company's OE go-live by improving reliability and performance. The project scope includes: (1) upgrading the Sitecore content management software to include content hosting and delivery allowing the use of new features and functionality; (2) migrating the Sitecore platform to the most up-to-date hardware and software by refreshing the application and database servers to a newer version of Windows Server and SQL Server. Alternatives considered include: (1) Delay the upgrade. This alternative was not chosen due to the current version falling outside of the mainstream support window, requiring additional 10% in maintenance fees. Along with rapidly changing feature sets that are continually being developed by the vendor, the Company would be in a worse position to handle constantly changing cyber threats; (2) Migrate to a cloud solution. This alternative was not chosen due to the cost/benefit analysis of re-architecting our current Sitecore implementation to facilitate dual migration is not viable at this time; and (3) Upgrade Sitecore on a two-year cycle. This alternative was chosen as it provides upto-date functionality, stability, and mitigates cyber security risks while minimizing cost and impact.	2025-01-16	2025-10-16	-1.00	116,432	245,030	ROM	36,595	-	-	23,887	-	1,672	11,036	91,168	-	-	-	85,204	-	5,964	-
248	2025	30% ROM Adjustment - Customer	Software(intangible)	Customer	This is for the 20% ROM Adjustment for IT projects.							(138,996)	-	-	(87,208)	(56,578)	(7,269)	(87,947)	-	-	-	-	-	-	-
249	SUBTOTAL	2025 Customer										3,059,541	-	-	1,346,928	883,409	106,101	720,203	1,058,867	-	-	376,374	140,832	78,953	19,729
250	2025	Application Currency-Electric & Gas Shared-Capital	Software(intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in the project to complete expense activities as associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Electric and Gas Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Electric and Gas Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	124,000	184,000	ROM	38,600	-	15,715	15,715	-	7,200	-	68,575	-	-	-	64,089	-	4,486	-
251	2025	Application Currency-Electric & Gas Shared-O&M	Software(intangible)	Electric & Gas Shared	The Electric and Gas Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Electric and Gas Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Electric and Gas Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	-	493,166		-	-	-	-	-	-	-	183,506	-	-	-	166,707	5,129	11,670	-
252	2025	Application Currency-Operational Technology-O&M	Software(intangible)	Electric & Gas Shared	The Operational Technology initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor support versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective databases, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	-	102,802		-	-	-	-	-	-	-	38,253	-	-	-	32,458	-	5,794	-
253	2025	Product Family Enhancements-Electric & Gas Shared-Capital	Software(intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities as associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Electric and Gas Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using a categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project forth is the Company ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	848,304	65,300		286,628	-	11,315	31,526	110,948	8,486	104,348	24,296	-	-	930	8,558	13,767	1,042	-
254	2025	Product Family Enhancements-Electric & Gas Shared-O&M	Software(intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Electric and Gas Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using a categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project forth is the Company ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	183,449		-	-	-	-	-	-	-	68,261	-	-	986	57,608	5,129	4,538	-
255	2025	Spatial Asset Management	Software(intangible)	Electric & Gas Shared	This initiative will implement SAP's Spatial Asset Management module. It will allow users to view assets, notifications, and orders geospatially using a map. The module will allow the Company to create and maintain asset maintenance plans for each segment of our gas and electric distribution networks (linear assets). The Company will create linear assets as technical objects (such as functional locations and equipment) and store linear data. The Company will enable creation of maintenance plans for these technical objects which result in notifications, maintenance orders, and measurement documents. We will enable monitoring the condition of our linear assets, identify where there is damage or a defect (as right start point and end point and offset), and manage all types of maintenance tasks (planned, unplanned, and preventative). Currently, the Company lacks spatial visualization and spatial awareness of work and assets impacting requirements for first time quality and impacting the ability to plan, bundle and execute nearby work. The lack of a linear asset management capability affects the full work management value stream resulting in overproduction of asset maintenance activity such as assessments, surveys, and inspections. This project creates value for the Company by (1) providing capability in SAP to view assets, notifications, and work orders on a map; (2) providing location awareness in SAP for assets and work; (3) establishing linear asset management capability in SAP for gas and electric delivery networks; and (4) enabling end-to-end map-based workflows. The scope of this project encompasses implementation in SAP of the Spatial Asset Management module. Alternatives considered include: (1) implement a cloud-based individual asset integration between GIS and SAP. This alternative was not selected as it proves ineffective in addressing needs of the end-to-end work management value stream while increasing the technical footprint of customization. There are also performance concerns with cloud to on-premis integrations; (2) implement work group centric approaches to viewing work on a map. This alternative was not selected as it does not support standard operation through the entire work management value stream; (3) Do nothing. This alternative was not selected as this would result in increasing costs and inefficiencies in gas and electric work management; and (4) The alternative to implement the Spatial Asset Management module in SAP was chosen as it expands use of a core technology investment, supports current investment in our work management value stream, and is compatible with our GIS technology.	2023-12-04	2025-11-30	-1.00	3,158,109	206,194	ROM	228,385	-	-	62,860	113,148	12,321	36,056	39,811	-	-	-	14,883	22,324	2,604	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

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Date: December 2024

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	SPEND YEAR	PROJECT NAME	RERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
256	2025	Standard Work Plan	Software(intangible)	Electric & Gas Shared	The Gas and Electric Resource Planning process is solely reliant on spreadsheets and manual data collection from numerous, disparate sources. It is not only time-consuming but also prone to errors, leading to potential inefficiencies in resource allocation and a lack of detailed, insightful planning. The sole use of spreadsheets makes analyses and what-if scenario development cumbersome. The lack of workplan controls contributes to the completion of just-ahead-work resulting in unnecessary OT and contractor expense. Implementing a controlled replanning platform that will interface with existing systems like SAP, DAMP, and EAM Dashboard would transform our planning organization, offering a clear view of planned work and ensuring that executed work is aligned with strategic objectives. In addition, a more integrated system that leverages automation and real-time data analytics would allow for the immediate, what if scenario planning the business needs to support sound, data-driven decision-making. The tool, alongside necessary process and system enhancements will enable the workflow and ultimately lead to schedule quality and ensure prudent overtime and contractor usage through reducing the amount of unattended work breaking into the work management process. A shift to a digital solution that fully aligns resources, work units and feeds the schedule will represent a significant step forward in resource management, aligning with modern best practices. The Gas and Electric Resource Planning process is solely reliant on spreadsheets and manual data collection from numerous, disparate sources. It is not only time-consuming but also prone to errors, leading to potential inefficiencies in resource allocation and a lack of detailed, insightful planning. The sole use of spreadsheets makes analyses and what-if scenario development cumbersome. The lack of workplan controls contributes to the completion of just-ahead-work resulting in unnecessary OT and contractor expense. The project will add value by: (1) improving Work Planning Annual Forecast Process. This involves the enhancement of automated inputs, processing, and reporting with a shift towards a more asset-driven prioritization method and; (2) converting Monthly Work Plans into Weekly Schedules. Establish a process that seamlessly transforms monthly plans into executable weekly schedules for easy handoff from planning to scheduling; (3) providing the ability to Run Forecasting and Planning Scenarios. Execute forecasting and planning scenarios and provide comparative analysis; (4) improve system reliability of Work Planned jobs increasing forecast accuracy of downstream processes; and (5) creating multiple dashboards based on the audience of the data providing visibility across all levels of Operations Leadership as well as Supply Chain proactively informing of upcoming work need, potential gaps, opportunities for contingencies if levers are pulled and clean executable work keeping our workforce fully engaged and productive. This results in improved Field Operations and Customer Satisfaction with delivery commitments and meeting reliability and compliance dates. The project scope includes the following: (1) developing a system for Work Planning Annual and Monthly forecast with automation; (2) creating the ability to translate the Monthly forecast into an executable Weekly Schedule; (3) creating technology for running Planning Scenarios with ability to compare scenarios for optimized field execution; (4) improving system visibility of Work Planned jobs increasing forecast accuracy of downstream processes (ie. material); and (5) building Dashboards and reports to provide visibility and help management maintain process control. Alternatives considered: (1) Purchase commercially available system. The option was not selected as a single all-encompassing system does not link the Annual forecasting to execution. Products reviewed included Prometheus. (2) Microsoft Excel based solution, extending the Microsoft excel based solution was not selected as it does not provide the level of data integration for controlling large number of forecasted work items. (3) Development of a system that integrates with our SAP investment. This option was not selected as it does not align to expected value delivery timeline. (4) Purchase a SaaS solution to enable planning & forecasting with integration to our SAP work management system. The fourth alternative was elected because it aligns to the expected value delivery timeline and meets the functional requirements.	2024-06-04	2025-12-28	-0.98	922,640	5,584,900	ROM	218,918	-	-	128,863	81,738	14,741	64,601	166,411	-	-	-	114,969	40,555	10,887	-
257	2025	30% ROM Adjustment - Electric & Gas Shared	Software(intangible)	Electric & Gas Shared	This is for the 20% ROM Adjustment for IT projects.							(130,600)	-	(1,163)	(81,488)	(38,978)	(6,864)	(20,132)	-	-	-	-	-	-	-
258	SUBTOTAL	2025 Electric & Gas Shared										709,021	-	23,887	197,476	266,841	35,963	186,874	589,114	-	-	1,917	459,271	86,905	41,021	-
259	2025	Application Currency-Gas O&M	Software(intangible)	Gas	The Gas Engineering and Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Gas Engineering and Operations digital systems addresses what is required by the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Application within the Gas Engineering and Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of these efforts. During this review, the alternative of delaying the timing of the individual upgrades is considered based on (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) prevent ing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	-	105,192		-	-	-	-	-	-	-	105,189	-	-	1,917	98,307	-	6,882	-
260	2025	Gas Distribution Probabilistic Risk Model	Software(intangible)	Gas	The project will implement a risk analysis model for comprehensive predictive risk analysis and modeling on gas distribution pipeline assets. Relative risk models are unit-less measures of risk derived from input information using qualitative data and ordinal scales to produce "risk index" scoring, in simple terms, the relative risk model does not provide true statistical measures. The risk assessment used in the current model provides a score for likelihood, consequence, and risk that is relevant only in comparisons to other scores. While the outputs provide a sense of relative risk when comparing no pipeline with another, the scores do not provide quantitative scales for probability, frequency, or expected loss of events. Although pipeline operators commonly use relative risk models, the quality of the relative risk ranking relies on subject matter expert inputs, human preferences, and assumptions. Completion of this project will provide value to both the Company and its customers. The project scope encompasses the implementation of a probabilistic risk model for gas distribution. Alternatives considered for the project include: (1) implement a custom, Excel-based probabilistic risk model through a consulting effort. This alternative was not selected because although the effort minimizes the IT cost of the project, the model creation from all secondary data sources, leading to multiple "sources of truth". (2) Implement a custom built probabilistic risk model. This alternative was not selected because the custom built solution is analyzed are not mature and have not been widely tested with transmission operators.	2025-10-01	2027-10-31	-1.00	4,510,700	41,870	ROM	2,431,430	1,800,000	-	210,000	175,000	26,950	219,470	26,394	-	-	7,440	17,227	1,727	-
261	2025	Gas SCADA Software Solution	Software(intangible)	Gas	The Gas Supervisory Control And Data Acquisition (SCADA) software solution project will replace the current Gas SCADA Software with a more standardized software package enabling the Company to more efficiently meet Federal and MPSC requirements. The current Gas SCADA software solution was originally implemented in 2000 and was based on the gas system requirements at that time. While the solution has been maintained since its implementation, the Company's gas system has outgrown the current capabilities. As the solution ages, there is increased effort required to address obsolete application and database software architecture, and enhancements to the system are limited. To address the capability gaps, custom interfaces and integrations have been developed where each requires maintenance and support. This environment adds complexity and cost to solution upgrades and troubleshooting issues. The current Gas SCADA solution will limit the ability to invest in digital solutions for increased system health monitoring and preventative maintenance capabilities due to the complexity to integrate these future capabilities with it. The project will add value by: (1) reducing risk of non-compliance by improving the ability to document and follow State and Federal requirements, improving customer safety; (2) improving efficiency and reliability when performing routine software upgrades, because standardization of the Gas software fleet has less risk of breaking during upgrades, as opposed to more custom-coded software; (3) reducing maintenance costs due to fewer individual software programs and less custom code; (4) improving Gas Control management capabilities that support the Federal and MPSC requirements for gas pipeline and Gas Distribution operations; (5) improving reliability by using proven gas industry standard software with configurable functionality, rather than a fully custom and system that has the possibility of being impacted by the next version update; (6) purchasing standard, out-of-the-box software that meets a high percentage of requirements and avoids multiple custom applications and specialty coded programs to achieve results; and (7) providing a data link for capturing data required for use in computer-based preventative maintenance programs and more predictive technical spikes. In addition, implementing industry-specific software helps the collective gas industry users to encourage the vendor development of future versions with enhancements, which adds more value to gas industry users. The comprehensive Gas SCADA system is used to monitor and control the operating conditions of the transmission and distribution gas systems. The Gas SCADA system includes remote terminal units (RTUs), field devices (i.e. valves, meters, odorizers), and computers running SCADA software. This scope covers the Gas SCADA software solution only. The project scope includes the following: (1) significant planning, including consulting assistance, to define the implementation strategy for the effort, given the magnitude of the technology effort; (2) selection and implementation of a new Gas SCADA software solution; (3) planning of a phased rollout of new hardware and software; and (4) retirement and decommission rings of the legacy gas SCADA solution and equipment once the new system is fully tested and operational. Alternatives considered include: (1) continue to maintain the current solution, at the risk of increasing reliability issues that result in controlling and monitoring the Company's gas system; (2) invest in enhancing the existing Gas SCADA software solution which would introduce additional custom development and more parallel functions that may not be supported in future vendor releases; and (3) replace the solution with a gas SCADA software solution that meets requirements to support the Natural Gas Delivery Plan. Alternative three has been selected to ensure sustainability for this critical solution. The current legacy system is operating at well beyond its original design specification, so the potential points of failure are not fully known or understood. If the SCADA project is not completed, the legacy system could become unstable and impact Gas Control's ability to operate and monitor real-time system conditions, maintain safe operations, and compliance with regulatory requirements. It could also impact the ability to dismiss on new facilities which require remote monitoring or control or cause the need for 24/7 manual field monitoring of certain facilities.	2022-04-18	2025-12-31	-1.00	18,016,040	2,305,237		8,038,938	2,083,987	7,364	956,112	3,856,566	324,519	810,488	1,081,755	382,856	167,070	157,028	195,500	24,677	104,624
262	2025	Gas T&D Historian	Software(intangible)	Gas	The Gas Transmission and Distribution (T&D) Historian project will replace the current historian for Gas T&D, eDNA (a traditional Supervisory Control and Data Acquisition (SCADA) historian product), and migrate to the standard OSIsoft PI enterprise historian system. The PI system is a suite of software products that are used to collect, store, view, analyze, and share operational data with systems users and subject matter experts. The historian for Gas Transmission and Distribution resides on a decades old platform and is not the Company's historian standard. Data access is cumbersome, requires multiple tools to access it, and does not provide for the storing, analysis or visualization of operational data in a timely manner with appropriate change management control. With the implementation of smart meters, the Company standardized on the more robust OSIsoft PI historian which is used for: (1) Renewable Generation; (2) Electric T&D, and, (3) Smart Energy. The Gas T&D historian has yet to be migrated to OSIsoft PI, and the eDNA gas data has limited access ability and usability in its current state and is no longer supported by the vendor. In addition, maintaining the older platform requires the new system requires duplicate resources and skills. The project will create a more accessible and centralized data source with better controls that can be leveraged as the system of record. The project will add value for both Gas Engineering and Gas Operations organizations within the Company by: (1) informing decision making based on real-time situational awareness of Operations personnel for information that does not need to be monitored by Gas Control; (2) improving the ability to respond to abnormal situations that do not require immediate intervention through that direct communication to Operations personnel; (4) providing information for the development of proactive and reactive plans to potential catastrophic events; (5) streamlining data access through visualization and analytics; and (6) reducing the waste of using multiple interfaces to interpret data. From an IT perspective, consolidating to one standard historian platform will result in savings in hardware, software, maintenance, resources and training. This scope of this project includes: (1) replacing the eDNA Gas T&D historian, a traditional SCADA historian, and migrating to the enterprise historian, OSIsoft PI; (2) developing analytics, visualization and reporting capabilities to support tracking of metrics and making operational decisions; (3) replacing the decades-old Microsoft Access-based custom Daily Gas Reports solution; and (4) retiring the legacy Gas T&D eDNA system (hardware and software). An alternative considered for the project was to upgrade eDNA Gas Historian to the latest version. This option was not selected because it requires a significant investment, and does not meet analytics, reporting, usability and access fully needs as well as the software owner has announced the "sunset" of the eDNA software. Furthermore, the Company standard for historians is OSIsoft PI and maintaining two platforms results in redundant efforts in training, support personnel and technology. The option to replace eDNA with the Company standard OSIsoft PI historian was selected to eliminate duplicate training, support personnel, and technology and to leverage the more robust data analytic capabilities in the OSIsoft PI tool set. Currently there is an effort with the Gas SCADA Software Solution to eliminate the need for a two-duplicative historians while the Gas SCADA Software Solution is being implemented. If this project is not completed, an interruption of our operational data reporting capabilities could occur and could result in a non-compliance and could potentially interrupt certain accounting and billing functions.	2024-02-19	2025-12-15	-0.93	1,496,412	241,715		768,636	-	160,500	410,223	-	212,893	-	224,700	-	-	10,000	200,000	14,700	-
263	2025	Product Family Enhancements-Gas Capital	Software(intangible)	Gas	The Gas Engineering and Operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Gas Engineering and Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Gas Engineering and Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering and Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and ensures requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	679,909	85,438		679,909	-	14,393	262,355	196,160	31,000	176,000	85,438	-	-	31,098	15,000	39,340	-
264	2025	Product Family Enhancements-Gas O&M	Software(intangible)	Gas	The Gas Engineering and Operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software applications changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Gas Engineering and Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Gas Engineering and Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering and Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and ensures requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	239,401		-	-	-	-	-	-	-	359,401	-	4,242	202,019	13,256	19,884	-
265	2025	Tracking & Traceability	Software(intangible)	Gas	Tracking and Traceability is a project driven from proposed regulatory rules that will require utilities to map new and replacement installations with tracking and traceability data for plastic pipe, fittings, and fusions for the lifetime of the asset. The Company does not currently have a Tracking and Traceability program that will meet PHMSA proposed requirements (PHMSA-2014-0086) also known as the Plastic Pipe Rule. Tracking and traceability systems tie the collection of information that provides manufacturing, material type, and location information for pipe and components. PHMSA defines the terms. This project will develop a sustainable Tracking and Traceability program that will meet PHMSA requirements (PHMSA-2014-0086) which address the proposed tracking and traceability requirements. The project adds value by capturing traceability data via barcode readers and location tracking information via Global Positioning System (GPS) equipment to improve the quality of data and assist the Company in determining future scopes of work in the event of any component manufacture recalls. The scope of work will include: (1) changes in SAP Supply Chain processes to capture the required barcode information for all plastic components used in gas distribution and service lines; (2) changes in SAP Work Management processes to account for capturing barcode information as part of material components added to work orders, capturing fusion information from work order completion and capturing GPS coordinates from work order completion; (3) changes in GIS to capture GPS coordinates of plastic components and GPS coordinates of component fusions; (4) building of a repository for tracking and traceability data and analytics; (5) purchase reading equipment for transmission and gas distribution tracks; and (6) purchasing of GPS locating equipment to capture coordinates. Alternatives considered: (1) The do nothing alternative, which was not selected because it would expose the company to significant legal and financial risk resulting from non-compliance. (2) Internally develope digital technology supporting the tracking & traceability standards included in the PHMSA-2014-0086 plastic pipe rule. The second alternative is being pursued by the Company	2025-01-01	2027-06-30	0.00	14,864,950	2,488,640	ROM	3,138,430	-	291,250	1,730,000	324,000	143,780	837,400	510,390	-	-	395,000	82,000	33,390	-
266	2025	30% ROM Adjustment - Gas	Software(intangible)	Gas	This is for the 20% ROM Adjustment for IT projects.							(1,158,578)	(900,000)	(58,250)	(189,000)	(99,800)	(34,148)	(211,074)	-	-	-	-	-	-	-
267	SUBTOTAL	2025 Gas										14,980,738	3,123,067	395,157	3,180,600	4,651,004	704,985	1,816,368	2,223,267	382,856	171,312	800,892	532,983	140,400	104,624
268	2025	AFIP-Infoblox Refresh	Network	IT Digital Foundation	This project will replace the three legacy core components, Domain Name System (DNS) Infoblox Assets that are used to support customer interactions and ensure the stability of technology for business operations are obsolete or out of date, they are more expensive to support and can be more difficult to keep current with security updates. Concurrent Energy also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. The value of this program includes: (1) enabling Company to efficiently manage and control their network; and (2) providing Domain Name System. The scope of this project includes the replacement of DNS, DHCP and IPAM assets on a 5-7 years refresh cycle. The alternative considered was to continue operating on existing Infoblox equipment past the vendor's end-of-support date. This alternative was not selected because it exposes the Company to risk from unsupported software bugfixes, security updates, and other software fixes. The alternative to replace the existing Infoblox equipment with the latest hardware and software provided by the vendor was selected to avoid these risks and continue a regular refresh cycle.	2025-01-01	2025-12-31	-1.00	978,213	53,500		478,718	-	451,486	16,880	14,469	2,194	6,752	19,906	-	-	11,162	7,441	1,302	-
269	2025	AFIP-Local Area Network	Network	IT/Digital Foundation	This project will upgrade the Company's entire LAN and a significant portion of the Wireless Local Area Network (WLAN). At some Company locations, LAN equipment has been in service since 2011. The project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor supported, thereby ensuring support for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; (6) increasing user productivity through a higher performing wireless network, which increases the productivity and satisfaction of Company's office and field employees. The project scope includes: (1) refreshing the LAN equipment and software as well as all Company switches; (2) identifying the required features for the new equipment; (3) implementing the new equipment according to industry best practices; (4) replacing wireless network with upgraded infrastructure and verifying wireless coverage is as expected; and (5) collecting wireless survey data for all Company locations in order to design improved wireless network coverage. The alternative considered was to continue operating on the existing platform past the vendor's end-of-support date. The vendor support period ended in May of 2018, and paying for extended support is not an option offered by the vendor. The risk inherent in not refreshing the platform is a lack of vendor support resulting in an absence of software bug fixes, security updates, and break fixes. The Company chose to replace the existing equipment with the latest hardware and software available, following a five year refresh cycle.	2025-01-01	2025-12-31	-1.00	320,435	57,930		156,546	-	108,518	24,115	9,887	2,380	9,646	21,554	-	2,046	15,255	2,977	1,276	-
270	2025	AFIP-Radio	Network	IT Digital Foundation	This project will refresh hardware to include; 800Mhz Radios and infrastructure, cellular modems, plant radios and systems, cellular amplifiers devices, vehicle consoles in service trucks, other communications equipment, and associated test equipment. 800Mhz mobile, and portable radios, Plant radio systems, and Cellular modems support core business functions, life safety communications, and rapid response for restoration of customers service and critical infrastructure. Company radio and cellular systems must be refreshed on a scheduled basis or risk exceeding life expectancy and failing or becoming obsolete. The refresh of this equipment in a proactive manner is critical to providing service to customers. If these units are not refreshed, the increased risk of unit failure would result in interruptions to timely and concise communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, which risks life safety. The project creates value for customers and the Company by: (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk work spaces by replacing equipment with units that contain intrinsically safe batteries; (5) supporting continuous improvement and training by replacing equipment that is capable of capturing audio recordings; and (6) remaining in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure. The project scope consists of: (1) scheduled replacement of radios, modems, and consoles; and (2) installing additional radios modems and consoles as to satisfy growth requirements; and (3) scheduled replacement of out of date cellular and radio boosters. The alternatives considered included: (1) Replace the existing units with new units from other radio and modem manufacturers; (2) purchase new radio subscriber units from existing manufacturers.	2025-01-01	2025-12-31	-1.00	2,388,927	114,491		1,152,179	-	851,981	39,289	226,649	18,616	15,715	42,598	-	24,370	12,175	4,861	1,192	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025, and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHS-5)
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Witness: SHBaker
Date: December 2024

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	SPEND YEAR	PROJECT NAME	RERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAP ITALIZ ED FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION OF O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
271	2025	Application Currency-IT/Digital Foundation-Application Platforms-Capital	New Computers / Hardware	IT/Digital Foundation	The Application Platforms initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expensive activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective databases; (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Application Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of these efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employee's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future. This project will replace the Company's obsolete or out-of-date audio, visual, telephony and other communication collaboration tools and equipment. When Collaboration Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates. The project scope consists of: (1) annually replacing aging collaboration assets; and (2) installing new collaboration assets to account for evolving business requirements. The following alternatives were considered: (1) refresh visual assets and a portion of the audio assets; (2) refresh a portion of the audio assets only; and (3) refresh visual assets only	2025-01-01	2025-12-31	-1.00	61,446	20,335	ROM	15,116	-	-	10,372	-	726	4,066	7,566	-	-	6,420	-	1,146	-
272	2025	ARP-Collaboration	New Computers / Hardware	IT/Digital Foundation	This project will replace the Company's obsolete or out-of-date audio, visual, telephony and other communication collaboration tools and equipment. When Collaboration Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with Security updates. The project scope consists of: (1) annually replacing aging collaboration assets; and (2) installing new collaboration assets to account for expanding business requirements. The following alternatives were considered: (1) continue to operate hardware beyond a five-year refresh cycle as long as it remains functional; (2) refresh a portion of the audio assets only; and (3) refresh visual assets only	2025-01-01	2025-12-31	-1.00	1,189,835	226,189		372,708	-	273,999	60,233	33,208	5,363	-	84,158	-	25,673	25,221	29,438	3,826	-
273	2025	ARP-Field Device Asset Management (FDAM)	New Computers / Hardware	IT/Digital Foundation	This project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failure, security patches, and software compatibility. When Field Device Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with Security updates as equipment becomes obsolete. This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing field devices prior to increasing hardware failures; and (2) allowing field workers to complete their job tasks. The project scope consists of replacing field device assets according to the four-year refresh cycle. The alternatives considered were to: (1) extend the replacement cycle from four years to five years for field devices; and (2) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the assets that need refreshing in future years based on the number of devices that were not replaced during the current refresh cycle; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the five-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company elected a four-year refresh cycle to alleviate these concerns.	2025-01-01	2025-12-31	-1.00	1,081,280	17,224	-	1,081,540	-	1,061,280	17,224	-	1,206	6,889	1,860	-	1,860	-	-	-	-
274	2025	ARP-Operational Technology Support Gas	New Computers / Hardware	IT/Digital Foundation	The ARP- OT Support Gas project will replace dated and obsolete servers on a rotating 5-year refresh schedule. When OT Assets that are used to support customer interactions and ensure the stability of technology for business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with Security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value by maintaining the currency of the Company. The program scope consists of: (1) a replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements. The alternatives considered include: (1) continue to operate hardware beyond a five-year refresh cycle as long as it remains functional; (2) refresh hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five-year refresh cycle was not selected due to the risk that these hardware component failures would address system reliability and safety for customers. The Company chose the alternative to refresh this hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure that supports systems such as Gas SCADA and Gas Compression control systems.	2025-01-01	2025-12-31	-1.00	979,178	120,440		979,178	-	802,500	41,255	-	2,888	72,535	120,440	57,000	39,000	-	22,000	1,540	-
275	2025	ARP-Printer Asset Management (PAM)	New Computers / Hardware	IT/Digital Foundation	This project will replace and install select printers, plotters, and multi-function printing devices based on printer replacement assessments and a five-year refresh cycle. Printer service and usage history is evaluated and a determination is made if a printer can be repurposed instead of ordering a new one. When Printer Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with Security updates as equipment becomes obsolete. The project creates value for the Company by: (1) improving the dependability of these printer devices for employees. The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle. The alternatives considered for the project included: (1) a longer refresh cycles from three to seven years as well as running the assets to failure. The selection of a five-year cycle was deemed to be the best solution as it maximizes the life/cost of unneeded expense for replacement of assets that were still in good operating condition. Another alternative than five years is assessed monthly to ensure it is not run to failure, including running the asset to failure, resulting in additional expenses for maintenance of the equipment and downtime, negatively affecting employee productivity. The Company assesses the printer fleet based on years of active service, service history, printer usage data, and the number of users within a facility. Based on these factors, the Company either decommissions, repurposes, leaves in place, or refreshes the printers.	2025-01-01	2025-12-31	-1.00	1,611,861	5,000		505,608	-	402,978	9,272	-	649	3,709	1,860	-	1,860	-	-	-	-
276	2025	ARP-Server and Storage	New Computers / Hardware	IT/Digital Foundation	This project will replace or augment server and storage infrastructure for the Company. When Server and Storage Hardware Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and can be more challenging to keep current with Security updates. This project creates value for the Company through: (1) improved stability and availability of business-critical applications by proactively replacing server and storage hardware assets prior to the likelihood of increasing hardware failures; and (2) ensuring that adequate resources are available to support application demands after five to seven years of utilization. The scope of this program encompasses: (1) replacement of server and storage hardware assets; and (2) installation of additional new computers and storage capacity to account for evolving business requirements. The alternatives considered were to: purchase extended maintenance, move some of these assets to the Cloud with the Digital -Hybrid Cloud and Data Center Migration project, or to replace these assets on the current cycle. The option to purchase extended maintenance was not selected because a full support would not be offered after seven years, and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital Hybrid Cloud and Data Center Migration project while refreshing the remainder using the five- to seven-year cycle as it is the most cost-effective option in IT the Digital Hybrid Cloud and Data Center Migration project is not approved as part of this rate case, the Company plans to continue to refresh these critical technologies at the current level based on a five- to seven-year refresh cycle to mitigate the risk of failure.	2025-01-01	2025-12-31	-1.00	1,739,577	139,100		546,749	-	378,222	110,005	-	7,700	50,822	51,755	-	-	48,369	-	3,386	-
277	2025	ARP-Workstation Asset Management (WAM)	New Computers / Hardware	IT/Digital Foundation	This project will replace and install new desktops, laptops, and tablets on a five-year refresh cycle based on industry standards, hardware failures, security patches, and software compatibility. Monitors will be replaced every eight years based on Company data related to its tonal failure rates. When Workstation Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improving stability and availability of business critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing business partners to complete their job tasks. The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources. The alternatives considered were to: (1) extend the replacement cycle from four years to five years for all desktops and laptops; (2) extend the replacement cycle only on desktops from four years to five years; and (3) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the ARP in future years based on the number of devices that were not replaced during the four-year refresh cycle; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle for desktops, laptops, and tablets; and an eight-year cycle for monitors to alleviate these concerns.	2025-01-01	2025-12-31	-1.00	8,982,469	89,935		2,815,190	-	2,083,128	66,317	39,700	7,428	26,527	33,462	-	31,763	1,588	-	111	-
278	2025	Digital-Hybrid Cloud and Data Center Migration	New Computers / Hardware	IT/Digital Foundation	This project will optimize data center assets and asset replacement project purchases by migrating or retiring applications out of existing Company and co-location data centers into cloud services, reducing operational costs for running IT services and leveraging increased cloud capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services. The technology currently deployed in the Company's data centers needs many customers' needs today. However, the pace of digital transformation is increasing rapidly, and requirements for applications are evolving faster than the technology in the Company's data centers can respond in a cost-effective manner. These data center constraints lead to longer implementation times, missing capabilities, or reduced functionality in the applications that the Company can deploy. This project will create value by ensuring the Company's technology requirements are met through a comprehensive and cost-effective combination of data centers and public cloud services. Specifically, by migrating applications to cloud services, the project will: (1) reduce capacity, hardware maintenance, and security device assets at the co-location data center; (2) reduce hardware maintenance and security device costs at the production data center; (3) enable the ability to scale infrastructure quickly up or down without costly up-front hardware purchases; (4) reduce application risk through cost-effective, scalable infrastructure redundancy and availability; (5) reduce ongoing server and storage asset replacement costs; (6) reduce ongoing networking equipment replacement costs; (7) reduce operational support costs; and (8) enable the use of a variety of cloud services to support Company applications. The project scope includes: (1) preparing the co-location data center to become the primary data center for on-premise IT services; (2) demoting the Company's production data center to the disaster recovery data center for on-premise IT services; (3) analyzing applications for migration to cloud or retirement; (4) migrating applications from on-premise to cloud; (5) transforming applications to use cost-effective cloud services; (6) starting network architecture and deploying base infrastructure to allow each location (on-premise or cloud) to function independently; (7) deploying cloud and on-premise cost management tool/agreed processes; (8) simplifying and optimizing backup and disaster recovery resources and processes using cloud services; (9) implementing additional automation for application deployment and management; (10) changing the operations model for support of cloud-based applications; (11) educating and increasing the skills of IT and other employees in leveraging public cloud services; and (12) transforming IT to become the broker of cloud services for the Company. Alternatives considered included: (1) migrating to public cloud services faster. This alternative was not chosen because the Company's ability to absorb new technologies coupled with their investments the Company has already made in data center equipment would prevent a faster move from being efficient and effective, intoducing additional financial risk; (2) migrating to public cloud services slower or not at all. This alternative was not selected because delaying public cloud services and capabilities coupled with requiring an extension of the life of existing data center equipment creates increased financial and operational risk; and (3) contracting with an outside vendor to provided cloud services to run applications for the Company. This alternative was not selected because industry information shows the option as not yet cost effective or not providing a maturity level that the Company would be able to easily consume with limited in-house experience and expertise in public cloud. The alternative to migrate to a hybrid cloud and data center model was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.	2023-02-01	2025-12-30	0.17	6,876,180	5,887,409		598,268	56,574	-	325,187	-	46,426	130,075	215,877	-	-	176,717	-	12,370	26,789
279	2025	SAP HANA Database Migration	New Computers / Hardware	IT/Digital Foundation	In preparation for SAP's planned end of support for its Business Suite product in 2027, the Company will migrate its existing SAP databases from Oracle to SAP HANA in advance of the required move to S/4HANA. The Company's SAP application currently utilizes Oracle's relational database management system as their underlying database storage technology. SAP has informed its customers that standard support for its legacy Business Suite (aka ECC) product will end in 2027, along with support for all non-SAP database platforms. SAP has also informed customers that the future direction for their enterprise solution is S/4HANA, a solution built explicitly for their HANA database platform. To prepare for these upcoming events, the Company will migrate all of its SAP databases off of Oracle and onto SAP HANA. This project leverages the groundwork for the company's eventual shift to SAP's HANA-based solutions by: (1) proactively migrating SAP databases to a database technology that is fully supported by SAP beyond 2027; and (2) mitigating the risk of a complete loss of support for the current Oracle database technology in 2027. Project scope includes: (1) procurement of HANA software licensing to cover all migrated SAP applications; (2) data migration for all SAP applications from the Oracle database to SAP HANA; and (3) implementation of new application support policies, procedures and tools required to manage the newly migrated SAP HANA applications. Given SAP's announcement regarding the end of support for its ECC product in 2027, all customers running SAP on database software other than HANA will also lose support for their associated database software in 2027. SAP is offering no other options for databases other than HANA beyond 2027. While there is no alternative to the HANA database for SAP going forward, the Company has considered multiple options: (1) Perform this project but not migrate from SAP Business Suite on Oracle to S/4HANA. A direct migration to S/4HANA brings greater operational risk to the Company as both the underlying database technology and the SAP application's functionality would change simultaneously, so this alternative was not selected. (2) Remain on the current SAP Business Suite product but competitively bid support services to a third-party provider instead of SAP. This alternative was not selected because moving to a third-party support model forces the Company to remain on outdated SAP software and eliminates any possibility of benefitting from new business functionality provided by S/4HANA. It will also require the Company to accept significant risk due to the fact that SAP security patches, application patches and upgrades will not be available upon termination of the SAP maintenance agreement. (3) Migrate to SAP's Software as a Service (SaaS) implementation of S/4HANA. This alternative was not selected because an S/4HANA SaaS migration is a much more disruptive option as the Company's business processes are structured differently between ECC and S/4HANA. The risk of negative business impact is significantly greater than simply changing the underlying database technology. (4) Migrate the SAP databases to HANA prior to implementing S/4HANA. This alternative was selected as it gives the Company several years to solidify its HANA database infrastructure before introducing the substantial business process changes required with S/4HANA.	2023-04-24	2025-12-31	-0.78	6,491,044	1,352,658		530,038	-	-	57,920	396,598	27,762	47,757	152,783	-	-	58,415	84,373	9,995	-
280	2025	20% ROW Adjustment - IT/Digital Foundation	New Computers / Hardware	IT/Digital Foundation	This is for the 20% ROW Adjustment for IT projects.							(1,036)	-	-	(2,074)	-	(149)	(813)	-	-	-	-	-	-	-
281	2025	Application Currency-IT/Digital Foundation-Application Platforms-O&M	Software(intangible)	IT/Digital Foundation	The Application Platforms initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective databases; (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Application Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of these efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employee's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future. This project will replace the Company's obsolete or out-of-date audio, visual, telephony and other communication collaboration tools and equipment. When Collaboration Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates. The project scope consists of: (1) annually replacing aging collaboration assets; and (2) installing new collaboration assets to account for expanding business requirements. The following alternatives were considered: (1) refresh visual assets and a portion of the audio assets; (2) refresh a portion of the audio assets only; and (3) refresh visual assets only	2025-01-01	2025-12-31	-1.00	-	97,027		-	-	-	-	-	-	-	36,104	-	-	30,635	-	5,469	-
282	2025	Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M	Software(intangible)	IT/Digital Foundation	The Infrastructure Platforms initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Infrastructure Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective databases; (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Infrastructure Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of these efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employee's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future. This project will replace the Company's obsolete or out-of-date audio, visual, telephony and other communication collaboration tools and equipment. When Collaboration Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates. The project scope consists of: (1) annually replacing aging collaboration assets; and (2) installing new collaboration assets to account for expanding business requirements. The following alternatives were considered: (1) refresh visual assets and a portion of the audio assets; (2) refresh a portion of the audio assets only; and (3) refresh visual assets only	2025-01-01	2025-12-31	-1.00	-	20,699		-	-	-	-	-	-	-	7,522	-	-	6,382	-	1,139	-
283	2025	Data & Analytics Platform Rationalization	Software(intangible)	IT/Digital Foundation	This project will optimize the Data & Analytics system landscape by creating connections, migrating data into Data Lake 2.0 (DL 2.0), and building visualizations from the data in DL 2.0. Following the enablement of DL 2.0, retirement of the IT Data & Analytics legacy systems including SnipSite Data Lake (SDL), SAP Business Warehouse (BW), SAP Business Objects (BOBJ), Natrieve HANA, the BW Portal, and SnipSite Data Objects Data Services (BODS) systems will reduce the total cost of ownership associated with maintaining and supporting legacy systems. The IT Data & Analytics legacy systems (SDL, SAP BW, SAP BOBJ, Natrieve HANA, the BW Portal, and BODS) are outdated, inefficient, and become significantly more complex in nature with the introduction of DL 2.0. If these legacy systems are not retired, they will continue to cost the Company money as major investments are needed to maintain and support them. This platform rationalization project creates value for the Company and its customers by reducing the total cost of ownership associated with maintaining and supporting legacy systems including licensing fees, maintenance costs, infrastructure, and support resources. The project scope includes: (1) the assessment of the existing Data & Analytics platforms including SDL, SAP BW, SAP BOBJ, Natrieve HANA, the BW Portal, and BODS; (2) inventory of data and reports still being used by stakeholders; (3) determination of migration strategy; (4) data migration to the Azure Data Lake; (5) report migration to Power BI; (6) organizational change management; and (7) the retirement/decommissioning of the legacy platforms and applications. Alternatives considered: (1) upgrade legacy systems in place (on-premise). This alternative was not selected because this is costly and misaligned with the Company's cloud strategy. (2) Lift and shift the current on-premise systems to the cloud through the Hybrid Cloud Transformation Program. This alternative was not selected because it would duplicate the work being done as part of the DL 2.0 project and would not provide the same efficiencies that DL 2.0 introduces. The alternative to migrate all data sources to DL 2.0 and retire legacy systems was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.	2025-03-03	2026-08-14	0.15	10,002,200	1,660,500	ROM	3,086,340	31,430	-	178,192	1,781,938	12,478	82,325	412,084	-	-	37,225	372,254	2,604	-
284	2025	Enterprise Service Bus Application 2024-2025 Upgrade	Software(intangible)	IT/Digital Foundation	This project will upgrade and migrate the Business Works developer application to the next version. Newer ESB software versions offer improved integration with Rest/API services and applications. It is critical that this vital data tool or pathway be more scalable, secure, and capable of integrating to a service-based environment. In addition, the messaging and event modules within the ESB are currently outside of their standard support windows. While it is possible to continue to get extended support by paying an estimated premium of approximately $80,000 annually, this is just temporary to wrangle and serves only to delay the need for an upgrade. The value this project provides the Company includes: (1) to circumvent extensive payments for extend support purposes; (2) avoid technical obsolescence; (3) operational resiliency; and (4) improved administrative and operational efficiencies. The project scope includes implementing current version of all applications that are part of the ESB application, database version, and required database drivers. Alternatives considered included: (1) Accept the annual $80,000 extended maintenance cost. Given the critical nature of this application, it is not recommended to lose mainstream support for any of the applications involved. Any sustained ESB product deficiency would impact many areas of the Company, such as billing, revenue collection, and remote meter management. The current implementation of the ESB platform was built with 5 years of growth in mind. This alternative was not chosen due to risk to Company operations, and the additional expense. (2) Replace the on-premise upgrade plan to implement a cloud-based solution. A cloud migration would also take longer to complete, which would put the Company at risk of falling outside of the current vendor support window for the products current version. (3) Upgrade the existing application. This option was selected because it best meets the Company needs for the near future by restoring vendor support for fixes and patches, and enables product scalability to the measure required of business capabilities.	2024-09-04	2025-11-21	-1.00	-	784,244	ROM	-	-	-	-	-	-	-	389,103	-	-	270,283	-	18,920	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHB-5)
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Date: December 2024

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	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
285	2025	Iron Enterprise Edition 2026 Upgrade	Software(intangible)	IT Digital Foundation	The project will upgrade Iron Enterprise Edition (EE), which collects the reads from meters to ensure non-estimated tel accuracy. Iron Enterprise Edition (EE) is the Company's keystone application of the Advanced Metering Infrastructure (AMI), that provides 8 figures that includes time of use data. If this application does not stay current, the Company increases the risk bus ness operations co uld be interrupted or compromised. Iron Enterprise Edition (EE) is a key co mponent in keeping the Company current, with billing capacity, stability, and accuracy obligations. This project creates value for the Company by: (1) ensuring the features and functio nality needed to meet and exceed cus tomer satisfaction and billing accuracy are available to business partners and IT; (2) meeting information Security. The scope of this project includes: (1) upgrading the Iron Enterprise Edition (EE) application s to the next appropriate version; (2) migrating the database to the next version required by the application. Alternatives considered included: (1) Defer the upgrade. This alternative was not selected because it would decouple Iron EE (EE's Meter Data Management) from the Iron security infrastructure introducing application instability, security and dependency risks to the utility, possibly negatively impacting critical customer electric and gas billing operations. It would also likely affect other business critical Iron applications use, creating more expense to support and no ability to leverage updated tool capability (2) Replace the platform. Replacing EE/MDM would require the application business owners to undertake a new initiative mirroring the expense and efforts that went into the multi-million dollar project responsible for setting up and leveraging this utility. (3) Perform the upgrade. This option is superior for both our customers and our Company because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Iron products.	2025-07-29	2026-12-09	-1.00		695,277	ROM								48,856					3,196	
286	2025	Product Family Enhancements-Application Platforms Services-Capital	Software(intangible)	IT/ Digital Foundation	The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements that benefit the IT organization is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT finance and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	955,650	132,106		300,161	-	-	172,834	31,400	14,298	81,798	49,153	-	-	20,519	21,189	7,445	-
287	2025	Product Family Enhancements-Application Platforms Services-O&M	Software(intangible)	IT Digital Foundation	The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements that benefit the IT organization is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT finance and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	288,508		-	-	-	-	-	-	-	107,354	-	-	91,092	-	16,261	-
288	2025	Product Family Enhancements-Infrastructure Platforms Services-Capital	Software(intangible)	IT Digital Foundation	The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software & hardware and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements that benefit the IT organization is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT finance and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	1,094,270	148,589		348,939	-	-	210,563	18,858	16,059	98,449	55,285	-	-	34,199	12,713	8,374	-
289	2025	Product Family Enhancements-Infrastructure Platforms Services-O&M	Software(intangible)	IT Digital Foundation	The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements that benefit the IT organization is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT finance and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	143,393		-	-	-	-	-	-	-	52,104	-	-	44,212	-	7,892	-
290	2025	SAP S/4HANA Implementation	Software(intangible)	IT Digital Foundation	[redacted]																				
291	2025	Software Platform Refresh	Software(intangible)	IT Digital Foundation	The Software Platform Refresh project will upgrade server operating systems, hypervisors, databases and infrastructure platforms to retain low-cost vendor support. For systems that go beyond their normal manufacturer support ending, there will be increased support and maintenance fees of 20% to 100% above current support and maintenance depending on vendor. Completing the project allows the organization to (1) avoid high support costs; (2) provide for system security and (3) stay current to promote seamless interoperability among servers, applications, and databases. Aging platforms are more susceptible to security vulnerabilities and performance issues that ultimately could affect the business and customers. The project will add value for the Company by (1) avoid ing costs for special maintenance agreements required at the end of normal manufacturer support; (2) ensuring reliability and compliance with Information Security requirements; (3) improving data center environment stability and (4) avoiding the need for high-risk upgrades that cross multiple versions. The project scope includes: (1) upgrading operating systems and databases on servers that are near end of support with a given vendor; and (2) maintaining hypervisors and infrastructure platforms at the current version for stability and performance. A funding options matrix was completed to review the potential alternatives. The alternatives identified were: (1) Complete the full scope of the solution for $1 million in order to eliminate the need for ongoing extended support; (2) Reduce the scale of the solution, which requires $1.6 million in ongoing extended support; (3) Reduce the scale of the solution even further, which requires $2.4 million in ongoing extended support; (4) Do not complete a software platform refresh, which requires $1.3 million in ongoing extended support. Alternative 1 was selected as the most cost effective solution to ensure ongoing system stability; seamless integration and mitigation of cyber-security risks without the significant cost of extended support necessary for end of life software systems.	2025-01-01	2025-12-31	-1.00	-	113,463		-	-	-	-	-	-	-	42,219	-	-	39,457	-	2,762	-
292	2025	20% ROM Adjustment - IT/Digital Foundation	Software(intangible)	IT Digital Foundation	This is for the 20% ROM Adjustment for IT projects.																				
293	SUBTOTAL	2025 IT/Digital Foundation																							
294	2025	ARP-Cyber Security	Network	Security	This project will replace cyber security infrastructure to support increasing systems and application demands and to prevent system failures and service interruptions. When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates. This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations. The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a 3-5 year hardware lifecycle and (2) performing application upgrades. As part of the review process, the alternatives considered were to: (1) upgrade or replace only those assets identified in the plan; (2) upgrade or replace a portion of the assets identified in the plan. Option 1 was not chosen because it would result in continued refresh cycle for cyber security assets to avoid security risks, system instabilities, and out-of-warranty repair costs. Option 2 was not chosen due to the security risk inherent with not replacing assets per standard refresh cycle timelines.	2025-01-01	2025-12-31	-1.00	450,000	25,000		237,176	-	178,482	24,115	-	-	14,469	9,932	-	-	9,932	-	-	-
295	2025	TSA Critical Facility Structure	Network	Security	This project will implement enhanced security measures outlined by the Transportation Security Administration (TSA) for critical facilities sets in order to bring the locations up to enhanced status and avoid non-compliances. This project will increase the security and reliability of gas delivery to our customers while also meeting federal requirements. Pipeline facilities that are deemed critical are required to apply enhanced security measures. Today, the Company current has designated 4 locations as critical. However, based on the April 2021 update to the TSA Pipeline Security Guidelines, Section 5 (Critical Facility Criteria), a significant number of our gas infrastructure that were not previously subject to evaluation will now fall into scope. As the Company continues to analyze the remainder of our gas assets, there is the potential for an additional 1,000 pipeline facilities (pipeline interconnections, metering and regulation stations, compressor stations, operational control facilities, main line valve, tank farms and terminals, etc.) may be deemed critical. The Company will be taking a phased implementation approach and will begin the process by implementing the enhanced security measures at the remainder of our compressor stations. Failure to update our sites will put the Company out of compliance with the updated guidelines. This project provides value to the Company by: (1) implementing enhanced security measures outlined by the TSA for four critical assets; and (2) increasing the security and reliability of gas delivery to our customers while meeting federal requirements. This project will implement the following enhanced security measures: (1) access control; (2) access readers; (3) cameras; (4) video and audio programming; (5) fencing and barriers; (6) gates; (7) locks and key control; (8) fence intrusion; (9) subcontractor work of trending poles, etc.; (10) forklift lighting; (11) background investigations for personnel working at the sites; (12) security equipment maintenance and testing; (13) security vulnerability assessments; (14) security communication plans; (15) personnel training; and (16) security drills and exercises for the following locations. Alternatives considered were: (1) To not implement the enhanced security measures outlined by the Transportation Security Administration (TSA) for critical facility assets. This option was not chosen due to the risk of not complying with the TSA enhanced security measures. (2) To implement the enhanced security measures outlined by the Transportation Security Administration (TSA) for critical facility assets. This alternative was chosen to avoid the risk of not complying with the TSA enhance security measures, such as increased vulnerability of attacks, financial penalties, and operational disruptions.	2023-11-27	2025-12-28	0.00	9,088,335	584,724		2,192,000	-	1,000,000	400,000	800,000	-	152,000	85,600	-	-	80,000	-	5,600	-
296	2025	ARP-Physical Security	New Computers / Hardware	Security	The ARP Physical Security, formerly known as Physical Security Asset Refresh will enhance or replace physical security assets to provide improved visibility and incident resolution related to security concerns. The Company has several thousands of physical security assets currently in use including security cameras, motion detectors, intrusion detection systems, and card access systems. Current limitations include the lack of integrated solutions for centralized management, situational awareness, real-time monitoring, compliance with regulations and guidelines, and faster response rates to emergencies and incidents. This could result in the increase of potential security vulnerabilities, associated penalties, and reputational damage. The value provided by completing the project is to: (1) maintain compliance with State and Federal regulations; (2) reduce redundancies with less of a need for multiple cameras and reducing gaps in functionality; and (3) optimize overall system performance. Included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) security cameras for monitoring capabilities; and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detection systems, and card access systems. Alternatives considered include: (1) not refreshing physical security assets, and (2) defer a portion of the refresh of physical security assets per an asset refresh cycle industry standard. Alternatives 1 and 2 were not selected due to the risk of security concerns, incident resolution, and the inability to meet NERC requirements. The alternative selected maintains compliance, reduces redundancies and gaps in functionality, and improves performance of physical security systems.	2025-01-01	2025-12-31	-1.00	1,903,740	12,626		598,031	-	313,986	37,716	141,435	104,894	-	4,698	-	-	2,902	1,488	307	-
297	2025	Security/OT Field Modernization	New Computers / Hardware	Security	This project will implement new infrastructure for accomplishing improved security in the field for OT assets. Gas and Electric technicians are using corporate laptops to manage critical OT infrastructure which does not follow cyber security best practices for managing critical infrastructure. The value of this project is deploying dedicated company OT laptops and associated OT infrastructure that can move between OT locations only and providing a secure environment. This project will procure and configure approximately 130 devices that will be used to manage critical OT infrastructure. The Company reviewed several options to mitigate cyber security risks inherent with the use of standard corporate laptops managing critical infrastructure. The alternatives considered are: (1) Continue utilizing existing profile way of using Corporate domain laptops with software installed; (2) Engage in a custom design and implement a proposed infrastructure; (3) Considered to replace all allow use of all local access to critical systems; (4) Consider extending the OT network to remote Company locations; (5) Deploy a dedicated company OT laptop and OT communications circuits, which includes cellular connectivity. The dedicated OT laptop and communications circuits presented the best way to secure the critical infrastructure by limiting internet and e-mail access. Vendors and subcontractors could also utilize these approved dedicated systems for managing infrastructures they help support at Company locations. Based on the analysis performed, the Company chose to deploy a dedicated OT laptop and communications circuits.	2025-01-13	2026-06-01	-1.00	1,161,568	305,600	ROM	262,478	-	89,313	107,239	-	7,507	58,219	72,777	13,022	-	-	-	-	59,754
298	2025	20% ROM Adjustment - Security	New Computers / Hardware	Security	This is for the 20% ROM Adjustment for Security projects.							(32,496)	-	(17,910)	(21,448)	-	(1,501)	(11,644)	-	-	-	-	-	-	-
299	2025	Application Currency-Security-Capital	Software(intangible)	Security	This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Security global assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protection; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The applications upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risks; penalties/ impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Application within Security are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on (1) maintaining an optimal balance between keeping the application current and risk of failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	146,200	4,622	ROM	45,951	-	-	31,450	-	-	14,521	-	1,720	-	-	1,459	-	260	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHS-5)
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Witness: SHBaker
Date: December 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAP ITALIZ ED FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION OF O&M SPEND FOR APPICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
300	2025	Application Currency-Security-O&M	Software(Intangible)	Security	This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrade. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Security/Global assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (3) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within Security are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2025-01-01	2025-12-31	-1.00	-	155,827	ROM	-	-	-	-	-	-	-	57,909	-	-	-	49,137	-	8,772	-
301	2025	Enhancements-Security-Capital	Software(Intangible)	Security	This initiative will use Capital funding to make enhancements to existing technology and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements in accordance with accounting rules. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from review or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for the funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	1,598,988	99,967		508,562	88,189	7,985	160,393	70,062	176,273	-	37,195	-	-	2,703	19,151	15,340	-
302	2025	Enhancements-Security-O&M	Software(Intangible)	Security	This initiative will use O&M funding to make enhancements to existing technology and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for the funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2025-01-01	2025-12-31	-1.00	-	399,129		-	-	-	-	-	-	-	148,515	4,580	-	132,378	2,655	8,902	-
303	2025	Saviynt Enterprise Identity Governance and Access (EIGA) Implementation	Software(Intangible)	Security	This project will implement Saviynt EIGA modules, consolidate Identity Access Management (IAM) functionality into Saviynt, and retire the Identity Manager application. By implementing the new solution, the Company will optimize IAM functionality, eliminate redundancy, and reduce support costs. In addition, the project will integrate the OT network with the IAM solution that will allow for automated management of users and entitlements in the OT Active Directory domains and applications. The current version of Access Show reached end-of-life in December 2022, with support discontinued in January 2023. The application has numerous custom workflows and integrations, requiring professional services for ongoing use and changes. It lacks proper data analytics and reporting, posing risk such as inability to fix critical defects, software incompatibility, compliance issues, increased costs, and degraded performance. The Company uses multiple IAM tools, each performing critical functions, leading to numerous required interfaces and customizations. While beneficial for end users, these integrations increase the risk of system failure, higher support costs, multiple subscriptions, infrastructure and maintenance costs, and more expensive upgrades. The current solution built on SAP HR batch file processes that introduced failure points, delays, and data integrity issues. Failure in these processes can prevent new or transferred employees from accessing necessary systems, leading to operational disruptions and potential compliance risks due to inappropriate access retention. This project provides value by: (1) Consolidating multiple IAM platforms through the implementation of the Saviynt Enterprise IGA Module, reducing complexity and support costs; (2) Decreasing complexity and enhancing efficiency by reducing interfaces between multiple identity tools; (3) Improving the end-user experience and reducing human struggle with access requests through a new, intuitive portal design; (4) Minimizing custom code and focusing on configurations only by utilizing out-of-the-box functionality; and (5) Streamlining employee data processing with the implementation of a consolidated Identity Governance Administration (IGA) platform. (2) Standardizing processes by removing custom code and using out-of-the-box functionality; (3) Right sizing and improving access security; (4) Addressing issues with aging applications vs. multiple IAM platforms, integration challenges, and anticipated HR process drag. Alternatives considered include: (1) implementing hot fixes to Access Now version 11.5 to ensure support through mid-2023; (2) Upgrading only the application to current supported version, including the new web portal but will including new application on function rolling; (3) Remaining on current version that will be unsupported as of January 2023, requiring vendor professional services for any break / fix. Patches and enhancements may potentially introduce additional risk of version instability; (4) Implementing IAM functions in Saviynt platform into manage access requests, including Active Directory, SAP, SAP HR, disconnected systems, and existing API integrations. The alternative selected was implementing the new Saviynt system, eliminating AccessNow software.	2023-11-27	2024-06-30	-1.00	5,913,132	710,912		597,282	-	31,480	96,804	345,730	43,518	79,800	167,555	74,414	-	52,276	-	3,659	37,207
304	2025	20% ROM Adjustment - Security	Software(Intangible)	Security	This is for the 20% ROM Adjustment for Security projects.							(9,130)	-	-	-	(5,286)	-	(2,904)	-	-	-	-	-	-	-
305	SUBTOTAL	2025 Security										4,513,894	88,189	1,603,365	829,963	1,357,227	343,107	291,844	585,669	92,016	-	380,157	28,294	42,961	96,961
306	TOTAL	2025																							
307	2026	2025 Union Contract Changes	Software(Intangible)	Corporate	The 2025 Union Contract Changes project will implement SAP and other system changes required as a result of three collective bargaining agreements which will be renegotiated and ratified. Collective bargaining agreements expire every five years for Operating Maintenance and Construction (OMC) Electrical Operating Maintenance and Construction (OMC) CCC (Customer Contact Center) and Zeeland employee groups. For OMC, the current agreement ends June 1, 2025. CCC agreement ends in August 1, 2025. Zeeland agreement ends October 1, 2025. Technology changes are required to reflect these new agreements. Otherwise, employees in these union groups may not be paid appropriately or get correct benefits. Completion of this project will provide value to the Company and its customers through: (1) ease to eliminate by making changes in the software for any pay and benefit changes as required by the new agreements; (2) defect reduction by adding process automation to otherwise manual processes for tracking and recording work, premium, and absence time; and (3) improved employee engagement among the OMC, CCC, and Zeeland union employees. The scope of this project encompasses making any system changes required to support the new working agreement for the OMC, CCC, and Zeeland employees. Exact details will be finalized after the negotiation process is completed and contracts are approved. Three alternatives were considered for this project: (1) Make no system changes after the contracts are ratified. This option was not chosen because it exposes the Company to possible fines, disengaged employees, unimplemented agreements, significant manual processes leading to greater possibility of errors, hiring additional staff to perform activities outlined in the agreements, and increased legal costs due to employee grievances. (2) Find other third-party software to support the changes required by the union agreements. This option was not chosen because it would require SAP integration along with additional software licensing and maintenance costs. (3) Make system changes to eliminate manual updating, comply with the working agreement language, support union employee engagement, and reduce grievances. Option (3) was chosen because it leverages current SAP technology, automates what would otherwise require manual processing, and is the least costly option	2025-04-01	2026-01-01	0.00	-	618,667		-	-	-	-	-	-	-	102,384	-	-	-	41,430	54,254	6,700	-
308	2026	Application Currency-Corporate-Capital	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Corporate Services adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective databases; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes. Applications within the Corporate Services are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	197,340	18,540		61,248	-	53,481	5,343	-	220	2,249	6,768	-	-	6,325	-	443	-
309	2026	Application Currency-Corporate-O&M	Software(Intangible)	Corporate	The Corporate Services initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Corporate Services adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective databases; (2) assessing any new functionality for value to the Company; (3) making necessary configurations changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes. Applications within the Corporate Services are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	332,567		-	-	-	-	-	-	-	120,853	-	-	112,947	-	7,906	-
310	2026	Asset Accounting Tax Upgrade	Software(Intangible)	Corporate	The project will upgrade our current accounting asset management tax software to the SaaS version as required by the vendor or a replacement solution and implement additional new features, ensuring continued support of a critical financial application, and providing new functionality. In 2026, standard vendor support ends for the current on-premise PowerTaxs software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial reporting and improve visibility. This project creates value for the Company by ensuring compliance with regulated and financial accounting with the fixed asset sub-ledger. In addition, the project adds value by: (1) moving to a SaaS solution in order stay supported; and (2) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support. The project scope includes: (1) evaluating current vendor/product solution with market leaders; (2) upgrading the vendor software from the current version to the newer SaaS version or replacing it. Alternatives considered include: (1) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (2) Do nothing and remain on unsupported, on-prem tax solution. This option introduces technical and financial risk which would be costly; (3) Upgrade to the newest SaaS version of current on-prem solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.	2026-02-01	2026-01-31	-1.00	-	1,572,781	ROM	-	-	-	-	-	-	-	122,121	101,011	-	9,864	9,864	1,381	-
311	2026	Asset Accounting Upgrade 2025-2026	Software(Intangible)	Corporate	The project will upgrade our current accounting asset management software to the latest version as required by the vendor, ensuring continued support of a critical financial application. Standard vendor support will be ending for the current on-premise software on an undisclosed timeline. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. There are also larger costs to upgrade if the upgrades are further apart due to complex trigger activities and too many versions increases at any one time. This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support; and (4) lowering costs with more frequent upgrades to reduce testing complexities and reduce the number of versions to be adopted. The project scope includes: (1) evaluating current vendor/product solution with market leaders; (2) upgrading the vendor software from the current version to the newer version. Alternatives considered include: (1) Evaluate SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, at a more, and not provide all the required features. (2) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (3) Analyze and go to do all possibilities (4) wait until a future upgrade; (5) Upgrade to the newest version of current solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrade, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing	2025-02-01	2026-01-31	-1.00	-	682,561	ROM	-	-	-	-	-	-	-	26,387	-	-	4,932	-	21,455	-
312	2026	Enterprise Risk Management	Software(Intangible)	Corporate	The project will implement software to simplify processes pertaining to Enterprise Risk Management, improve efficiency, provide risk identification and repository tools, and provide real-time risk information. The Enterprise Risk Team (ERT) works with Risk Owners (ROs) on an annual basis to identify new risks, update existing risks, quantify impacts and likelihoods of these risks, document mitigation plans, identify trends, and formulate risk tolerance metrics. This work is accomplished through an Excel workbook and Word process between ERT and ROs to gain alignment on content. This effort culminates in multiple Risk Map PowerPoint, Microsoft Word and email documents presented to senior management and to the Board of Directors (BoD) on an annual basis. The Interview, time-consuming manual Enterprise Risk Management (ERM) process creates risks of human error that can go undetected or create version tracking issues. The existing process results in substantial inefficient use of time by risk analysts and risk owners throughout the Company, limits the breadth of analysis that can be provided, and limits the overall ability of the Company to timely identify, analyze, and communicate risk to our senior leaders, thereby causing potential delay in responding to emerging risks. Because of the lengthy manual process, it is only performed once a year, but must be performed more frequently to proactively manage enterprise risk. Utility industry peers leverage software to more effectively manage enterprise risk management programs. This project creates value for the Company by: (1) providing real-time risk information to interested parties including risk champions, risk owners, senior management, and the Board of Directors (BoD) supporting proactive risk management; (2) creating a centralized and repository for risk identification, management, and mitigation plans; (3) eliminating waste by simplifying processes; and (4) improving efficiency of the risk owners and analysts. The scope of the project includes: (1) create risk analysis templates and models for automated reporting; (2) configure automated workflows for periodic risk updates; (3) configure dynamic templates that prompt the risk owners based on prior selections; (4) organize risk assessments through an online and searchable data capture (repository); (5) create new reports and executive dashboards; (6) data conversion; and (7) set record retention rules. Alternatives considered include: (1) Continue use of the current manual process which result in waste, lack of quality results, and annual review of risks; (2) Build a custom internal enterprise risk solution. This option was not selected as it will not result in an enterprise risk program that leverages best practices that exist in software provided by the leaders in risk management software; and (3) Implement a software solution from a leading enterprise risk solution vendor. While this would introduce new license and ongoing support costs, it is the preferred option because it leverages industry best practice with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation and insights via the reporting of risk information through management dashboards. In addition, it aligns the Company with utility industry peer practices for more effective enterprise risk management.	2026-01-01	2027-01-01	-1.00	-	609,253	ROM	-	-	-	-	-	-	-	31,708	-	-	9,773	21,246	688	-
313	2026	Expense Reporting Improvements	Software(Intangible)	Corporate	The Expense Reporting Improvements project will increase productivity when creating expense reports; leverage workflows for expense processing and exceptions; improve adherence to company policies, provide insights through improved reporting and minimize human intervention and struggle throughout the expense process. Multiple problems exist with our current expense reporting system in the areas of usability, employee engagement, inefficiencies, compliance, and audit exceptions. Submitting expense reports is not intuitive, leading to errors and the need for manual intervention. In addition, employees have to manually create risk analysis templates and models for automated reporting; (2) configure automated workflows for periodic risk updates; (3) configure dynamic templates that prompt the risk owners based on prior selections; (4) organize risk assessments through an online and searchable data capture (repository); (5) create new reports and executive dashboards; (6) data conversion; and (7) set record retention rules. Alternatives considered include: (1) Continue use of the current manual process which result in waste, lack of quality results, and annual review of risks; (2) Build a custom internal enterprise risk solution. This option was not selected as it will not result in an enterprise risk program that leverages best practices that exist in software provided by the leaders in risk management software; and (3) Implement a software solution from a leading enterprise risk solution vendor. While this would introduce new license and ongoing support costs, it is the preferred option because it leverages industry best practice with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation and insights via the reporting of risk information through management dashboards. In addition, it aligns the Company with utility industry peer practices for more effective enterprise risk management.	2026-06-01	2027-06-30	-1.00	1,212,000	216,600	ROM	185,248	-	-	62,860	78,575	9,900	33,913	52,238	-	-	-	29,765	14,883	3,125	4,465

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHS-5)
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Witness: Sheldon
Date: December 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	REIC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
314	2026	HR Support Pack and Business Software Inc Upgrade 2026	Software(Intangible)	Corporate	The Human Resources (HR) Support Pack and Business Software Inc (BSI) upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes. SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax change, resulting in the inability to calculate and distribute payroll. This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll. The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information to the Company. Alternatives considered include: (1) Not upgrading to the current support packs which results in noncompliance with financial rules and regulations and inaccurate payroll; (2) there is no economical cloud solution, so this option was not entertained; (3) apply the appropriate support pack upgrade. Option (3) is the preferred option because it enables the company to comply with HR and tax changes, resulting in the ability to correctly calculate and distribute payroll.	2026-02-05	2026-12-31	0.00	-	785,068		-	-	-	-	-	-	-	-	-	-	-	285,289	-	-	28,764	-	38,668	201,075	16,782	-
315	2026	Product Family Enhancements-Corporate Capital	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities as sociated with Capital enhancements. The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for small-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	2,929,434	418,489		930,721	-	-	591,703	12,572	42,299	274,147	155,706	-	-	197,045	8,475	10,186	-
316	2026	Product Family Enhancements-Corporate-O&M	Software(Intangible)	Corporate	The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities as sociated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	-	458,548		-	-	-	-	-	-	-	170,625	-	-	159,463	-	11,162	-
317	2026	Self Service Vendor Portal	Software(Intangible)	Corporate	The work will create an external portal for vendors to exercise self-service features to streamline and automate purchase order and invoice management and improve visibility to invoice and payment status. For Accounts Payable, vendors must repeatedly interact with the Company through multiple channels to ask questions, submit invoices, or check invoice or payment status, including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates, to make payments, or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for vendor invoice and payment management and lacks the ability for vendors to utilize business invoice creation from POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes 6 contracted resources, and creates the potential for late payments or missing early payment discounts. For Supply Chain, vendors must repeatedly interact with the Company through multiple channels to ask questions, update PO's (quantities, costs, shipping dates) including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for updates to the POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes 6 contracted resources. This also creates the potential for late payments, missing early payment discounts, delays in receiving due to lack of shipping notifications from vendors, delays to scheduled work due to lack of acknowledgement and lead time adherence, and the inability to enforce contractual obligations. This project creates value for the Company by: (1) creating self-service functionality/increasing touchless invoice creation/processing that also ses the vendor to select items from a purchase order to create an invoice on demand; (2) providing vendors with real-time invoice and payment status, increasing end-payer productivity by eliminating waste; (3) allow self-service updates of vendor master data (banking info, remittance info, etc.); (4) fewer late payments by vendors thus reducing Company follow up and tracking; (5) creating better visibility for vendors to take advantage of early payment discounts thus reducing related vendor inquiries; (6) reducing vendor questions related to invoice and purchase orders through self-service functions and portal information; (7) reducing the cost per invoice; (8) creating self-service functionality/increasing touchless PO creation/processing that also ses the vendor to select items from a purchase order to update quantities, costs, and shipping dates; (9) providing vendors with real-time PO information, increasing end-payer productivity by eliminating waste; and (10) fewer late deliveries by vendors thus reducing Company follow up and tracking. The project scope includes: (1) submit an RFP for a vendor portal solution and implementation; (2) configure ability for vendors to more efficiently and more accurately self-submit invoices and POs; (3) configure ability for vendors to self-convert items on a purchase order to an invoice; (4) configure ability for vendors to view invoice and payment status; (5) configure ability for vendors to make changes to SAP master data, including PO line item details; (6) configure ability to offer/process dynamic discounting; (7) create new reports and dashboards; (8) enable/embed tool to validate vendors should have access to the portal and removing access when appropriate; (9) configure ability for vendors to make self-serve changes to shipping status and delivery dates; and (10) integration to vendor invoice management system and SAP. Alternatives considered include: (1) Continue use of the current manual processes which results in waste and inefficiency for employees and vendors. This could also result in late payments and lost discounts for vendors; (2) Build a custom solution. This option was not selected as the Company has a vendor portal, that is only leveraged for vendor ask questions. As well, it doesn't leverage best practices; (3) Building a combination of custom and standard integration to existing solutions. This option was not selected because it doesn't follow industry best practices; (4) expand our current vendor portal. This option is not chosen due to limited functionality and roadmap, and (5) implement a new SaaS solution specific to a vendor portal experience. Option (5) is the preferred option because it leverages industry best practices with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation to vendors via real-time process sing.	2025-09-01	2026-08-15	1.13	134,816	1,839,600	ROM	41,378	-	-	27,658	-	1,936	12,778	47,774	-	-	14,883	29,765	3,125	-
318	2026	30% ROM Adjustment - Corporate	Software(Intangible)	Corporate	This is for the 20% ROM Adjustment for IT projects.							(57,776)	-	(10,686)	(19,172)	(15,715)	(2,411)	(9,811)	-	-	-	-	-	-	-
319	SUBTOTAL	2026 Corporate										1,151,789	-	40,745	668,393	75,652	51,964	315,276	1,121,853	139,775	-	801,096	339,563	82,155	4,465
320	2026	Application Currency Customer-O&M	Software(Intangible)	Customer	The Customer initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Customer digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impact stability and functionality, leading to fewer incidents due to outdated software; and (4) address repression interdependencies and repairability between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing new functionality for value to the Company, (3) making necessary configuration changes, (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications with Customer are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the funding of the individual upgrades is considered based on (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future	2026-01-01	2026-12-31	-1.00	-	183,110		-	-	-	-	-	-	-	65,609	-	-	61,317	-	4,292	-
321	2026	Customer Order Service Tracker	Software(Intangible)	Customer	Short cycle orders including gas emergencies and meter services account for many of the incoming customer inquiries to the contact centers. This project will implement a service order status tracker to provide transparency to customers and overnight to internal teams supporting utility service orders across Company service areas. The tracker will provide timely and accurate service order updates, creating a more robust customer experience for tracking service order status and location-based updates. Customers have limited visibility to when Company assigned crews will be on premise and what work will be completed. This is due to features missing within the Company's digital channels for accurate updates from dispatch, scheduling, and field crews. The lack of awareness drives calls into the call center, resulting in approximately 365,000 annual contact center calls related to short cycle requests. Additionally, this lack of visibility increases truck rolls due to dispatchers being unaware of crew locations and routes which can cause crews to be assigned when a local crew could have completed the work. This leads to overall customer dissatisfaction because of a lack of visibility to scheduled and ongoing short cycle work. Enabling a digital channel for communication regarding utility service orders will improve customer experience and reduce the waste of repetitive crew dispatching. This project will add value to the Company and its customers by: (1) providing transparency for customers on the timing and location of the associated crew completing utility short cycle service orders, (2) reducing calls to contact centers by customers seeking clarification regarding arrival times through visibility to scheduling, real-time crew locations and updated estimations to customers when crews are enroute, (3) improving service assignment by current location, which decreases wasted truck rolls through enabling location services for active crews, (4) increasing visibility into the service person(s) completing the order by enabling crews to connect with customers through digital channels, and (5) improving customer experience for short cycle service orders by implementing a channel of choice for Company interactions. The scope for the project includes: (1) modifying the customer self-service portal to include features that support utility service order tracking, including the location of crews en-route, (2) providing tasking and mobile capabilities, (3) enhancing the existing Geo wallenci platform to allow real-time status updates that can be communicated to customers, (4) utilizing location-based services to update internal portal in real-time, and (5) enabling text and email notifications to alert customers of service crews arrival times. Alternatives considered for this project include: (1) Daptay a mobile application to address utility service order tracking, (2) utilize a cloud hosted solution from a third-party, (3) modify the existing customer portal to enable customers and the Company to track utility service orders, and crews. Options one and two were not selected as the cost associated with deployment would greatly outweigh the benefits with poll reductions and improved customer experience. The third option was selected because it utilizes existing technologies, which reduces the implementation complexity and project cost and has faster value realization for the customer and the Company.	2025-01-10	2026-08-28	-1.00	4,021,500	1,186,250	ROM	505,588	-	-	141,435	188,580	23,101	152,467	189,039	-	-	55,810	74,414	9,116	-
322	2026	Energy Assistance Enhancements and Maintenance Annual Updates	Software(Intangible)	Customer	The Energy Assistance Enhancements and Maintenance Annual Updates project, formerly known as Consumers Affordable Resource for Energy (CARE) project, will implement software changes to offer energy assistance to low income customers and streamline the process for the assistance agencies who use the assistance portal. This is accomplished through improved user interface and updates to SAP processes various requests. Upcoming modifications will be identified following an ongoing and annual review of requests, that includes criteria from the Department of Health and Human Services (DHHS) and Michigan Public Service Commission (MPSC) to prioritize the list of changes. Each grant year, DHHS and MPSC stipulate the criteria required for customers to enroll in the CARE program, how the Company and agencies will manage the enrollment process and track active CARE customers, and how they will administer the Michigan Energy Assistance Program (MEAP) benefits through bill credits and arrears forgiveness. The criteria changes significantly each year, therefore, the Energy Assistance Enhancement and Maintenance Annual Updates application requires modifications to meet the new requirements. If the regulatory requirements are not fulfilled, the Company is at risk of losing state Low Income Energy Assistance Fund (LIEAF) funds to assist low-income customers with paying their energy bills, thereby increasing the customers risk of shutoff for non-payment. In addition, our energy assistance programs function within all software platforms in the company which consistently need enhancements and updates. The project will provide the following value: (1) complete modifications to internal SAP applications and Agency Portal to receive LIEAF funding, which can be used to provide customers their bill credits and arrears forgiveness; (2) improve the data within the assistance agencies portal, thereby making it easier to assist customers in need of LIEAF funding; and (3) complete modifications to customer facing platforms. The project scope includes: (1) updating the enrollment and status process; (2) allowing for multiple bill credits; (3) improving reporting; (4) updating the arrears forgiveness plan; (5) satisfying additional regulatory requirements for the annual grant rule changes required by the Department of Health and Human Services and Michigan Public Service Commission; (6) updating CARE during process; and (7) updating the assistance portal (CEPAS) functionality to enhance Agency Self-Service. Alternatives considered include: (1) continue with current process. This alternative was not chosen because it was utilized to loss of grant funding, thus decreasing or eliminating energy assistance dollars for customers; (2) transfer administration of Energy Assistance Programs to a third party organization. This alternative was not selected because it would remove ownership and visibility into the health of the program while increasing administrative costs; and (3) make small updates to the applications, which will allow agencies to easily enroll customers in assistance programs and allow placement of holds to stop or prolong credit activity until assistance decisions are granted. This option was selected since it provides long-term proactive energy assistance to customers and prevents loss of grant funds. Changes are required to internal systems such as SAP, a large internal system that supports broad areas of the business, and the Agency Portal, an internally developed web application, therefore a single cloud or third-party alternative is not viable. Additionally, retiring the existing Agency Portal for a new application would increase costs beyond that of the routine upgrades.	2026-01-01	2026-12-31	0.00	-	332,623		-	-	-	-	-	-	-	123,769	-	-	105,821	9,851	8,097	-
323	2026	Product Family Enhancements-Customer-Capital	Software(Intangible)	Customer	The Customer initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	5,820,555	757,158		1,828,401	-	-	727,570	718,671	55,035	328,125	381,714	-	-	239,189	18,392	24,134	-
324	2026	Product Family Enhancements-Customer-O&M	Software(Intangible)	Customer	The Customer initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	-	434,156		-	-	-	-	-	-	-	161,549	-	-	100,024	32,584	9,211	19,729
325	2026	Rate Change Maintenance	Software(Intangible)	Customer	The Rates Change Maintenance project will modify SAP billing in accordance with pricing and rate change requirements. For the Company to continue to meet and comply with the Michigan Public Service Commission (MPSC) rate change requirements, there is a need to make periodic updates/modifications to the existing price and rate structures. These updates help ensure accuracy of billing and provide optimal rates for customers. The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing, (2) optimized rate configuration enabling rate changes to be made more efficiently; and (3) timely updates to Company applications that incorporate mandatory changes to the rate structure that include new surcharges, price changes, and energy efficiency programs. The scope of the project encompasses: (1) implementation of annual or monthly (or both) electric and gas customer price changes, and rate structure changes as approved by the MSPC; and (2) optimizing the rate configuration in the Company's back-end systems for more efficient rate changes. An alternative considered for this effort was a fully dedicated offsite development model. The option ensured resources were readily available with a more cost-effective labor expense. This alternative was not chosen due to the risk of billing inaccuracies and customer complaints. These risks were deemed too high because of the complexity of the rate structure, new development, and the timing it would take for testing of this model. Cloud is not an applicable option in this case as we are not replatforming software. The option to use onsite resources to plan, coordinate, and execute the rate changes was selected as it supports the Company's operation model for rate changes.	2026-01-01	2026-12-31	0.00	-	318,120		-	-	-	-	-	-	-	118,372	-	-	110,628	-	7,744	-
326	2026	30% ROM Adjustment - Customer	Software(Intangible)	Customer	This is for the 20% ROM Adjustment for IT projects.							(118,137)	-	-	(66,297)	(37,736)	(4,670)	(10,455)	-	-	-	-	-	-	-
327	SUBTOTAL	2026 Customer										2,153,867	-	-	840,718	869,335	73,316	450,499	890,352	-	-	672,789	135,241	62,194	19,729

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHS-5)
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Witness: Sheldon
Date: December 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	RERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
328	2026	Application Currency-Electric & Gas Shared-Capital	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risks; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database; (2) assessing new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes. Applications within the Electric and Gas Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increase of number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	304,000	34,000		119,158	-	22,001	69,460	-	32,091	-	7,962	-	-	7,441	-	521	-
329	2026	Application Currency-Electric & Gas Shared-O&M	Software(Intangible)	Electric & Gas Shared	The Electric and Gas Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risks; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes. Applications within the Electric and Gas Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increase of number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	635,392	ROM	-	-	-	-	-	-	-	286,429	-	-	220,961	-	15,467	-
330	2026	Application Currency-Operational Technology-Capital	Software(Intangible)	Electric & Gas Shared	The Operational Technology initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Operational Technology logs adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risks; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database; (2) assessing new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes. Applications within the Operational Technology logs are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increase of number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology logs landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	225,228	55,469	ROM	91,582	-	-	38,018	-	2,661	14,903	20,638	-	-	19,288	-	1,350	-
331	2026	Application Currency-Operational Technology-O&M	Software(Intangible)	Electric & Gas Shared	The Operational Technology initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risks; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database; (2) assessing new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes. Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increase of number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology logs landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	325,990	ROM	-	-	-	-	-	-	-	121,301	-	-	113,365	-	7,935	-
332	2026	Next Generation electronic Shift Operations Management System(eSOMS)Replace(Software(Intangible)		Electric & Gas Shared	The project replaces the eSOMS with updated cadence lock out tags out ("LOTO") management software for Electric Generation facilities, and narrative log and mobile rounds functionality for Electric Generation and Gas Compression facilities. The vendor is replacing the current system used at the Company and other utilities with a new software package called Lumada. The software migration is necessary for the Company to retain vendor support, so that the databases on the now to receive security patches, bug fixes, and functionality support from the vendor, and avoid security, stability, and reliability risk. The project will add value by: (1) maintaining functionality of a critical life safety application; (2) reducing the human struggle that comes from manual workarounds and an older application; (3) empowering employees with proper electronic tools to meet customer expectations; (4) enabling process improvements to deliver outages more effectively; (5) reducing plant down time; (6) increasing reliability; and (7) increasing standardization across the Company. The scope of this project includes: (1) configuring software for clearance management, logbook, rounds, automated emails, and reporting; (2) migrating and archiving data; (3) enabling additional offsite capabilities; (4) integrating the Shift APP for equipment and current status of work orders; (5) add regime integration to SAP for notifications from rounds and clearance functions; (6) testing the software, data migrations and integrations; and (7) updating configuration management databases, runbook, system recovery plan, LOTO work procedures, qualifications training and other standard documentation. Alternatives considered include: (1) continuing to use the eSOMS application, though without vendor support. This alternative was not selected because losing vendor support for this critical application increases risks for application security, reliability, and supportability that can result in an employee safety incident in the complex tagging process, an extended plant production outage, a prolonged plant reliability issue, or regulatory or compliance violations. (2) instituting the manual business continuity process until the application replacement is possible. This alternative was not selected because it would also increase the previously mentioned potential risks. (3) Replacing the eSOMS application by customizing SAP. This alternative was not selected as it would be more expensive and introduce additional risk to employees due to poor application fit. (4) Migrating the existing eSOMS data to an out the box application such as the Lumada application. The option to migrate the existing eSOMS application to an on or off the box solution was chosen to minimize cost and risk to the Company and its employees. Cloud hosting of the application infrastructure at the vendor's location was also evaluated though due to the greater cost of this vendor hosting, the application infrastructure will be hosted on premise at the Company.	2026-01-19	2027-08-26	-1.00	912,523	45,658	ROM	188,639	-	6,086	88,255	47,146	6,313	40,859	9,892	-	983	4,742	3,721	446	-
333	2026	Product Family Enhancements-Electric & Gas Shared-Capital	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between investigation and implementation and cannot and should not wait for rate case approval at an individual line item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Electric and Gas operations is in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing Software applications investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	848,304	65,300		266,628	-	11,315	31,526	110,948	8,486	104,348	24,296	-	930	8,558	13,767	1,042	-
334	2026	Product Family Enhancements-Electric & Gas Shared-O&M	Software(Intangible)	Electric & Gas Shared	The Electric and Gas operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between investigation and implementation and cannot and should not wait for rate case approval at an individual line item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Electric and Gas Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing Software applications investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	-	183,449		-	-	-	-	-	-	-	68,261	-	-	57,608	5,129	4,538	-
335	2026	Standard Work Plan	Software(Intangible)	Electric & Gas Shared	The Gas and Electric Resource Planning process is solely reliant on spreadsheets and manual data collection from numerous, disparate sources. It is not only time consuming but also prone to errors, leading to potential inefficiencies in resource allocation and a lack of detailed, insightful planning. The sole use of spreadsheets makes analyses and what-if scenario development cumbersome. The lack of workplan controls contributes to the completion of jail-shaved work resulting in unnecessary OT and contractor expense. Implementing a centralized planning platform that will interface with existing systems like SAP, SWPP, and EAM Dashboard would transform our planning organization, offering a clear view of planned work and ensuring that executed work is aligned with strategic objectives. In addition, a more integrated system that leverages automation and real-time data analytics would allow for the immediate, what if scenario planning the business needs to support sound, data-driven decision-making. The tool, alongside new synapses and system enhancements will streamline the workflow and ultimately lead to schedule quality and ensure prudent overtime and contractor usage through reducing the amount of unplanned work breaking into the work management process. As a first-to-a digital solution that fully aligns resources, work units and feeds the schedule will represent a significant step forward in resource management, aligning with modern best practices. The Gas and Electric Resource Planning process is solely reliant on spreadsheets and manual data collection from numerous, disparate sources. It is not only time consuming but also prone to errors, leading to potential inefficiencies in resource allocation and a lack of detailed, insightful planning. The sole use of spreadsheets makes analyses and what if scenario development cumbersome. The lack of workplan controls contributes to the completion of jail-shaved work resulting in unnecessary OT and contractor expense. The project will add value by: (1) Improving Work Planning Annual Forecast Process: This involves the enhancement of automated inputs, processing and reporting with a shift towards a more asset-driven prioritization method and; (2) converting Monthly Work Plans into Weekly Schedules: Establish a process that seamlessly transforms monthly work plans into executable weekly schedules for each yard off from planning to scheduling; (3) providing the ability to Run Forecasting and Planning Scenarios: Execute forecasting and planning scenarios and provide comparative analysis; (4) Improve system reliability of Work Planned jobs: Increasing forecast accuracy of slow rate work processes; and (5) creating multiple dashboards based on the audience of the data providing visibility across all levels of Operations Leadership as well as Supply Chain proactively informing of upcoming workload, potential gaps, opportunities for contingencies if teams are pulled and clean executable work keeping our workforce fully engaged and productive. This results in improved Field Operations & Customer Satisfaction with delivery commitments and meeting reliability and compliance dates. The project scope includes the following: (1) Developing a system for Work Planning Annual and Monthly Forecast with automation; (2) creating the ability to translate the Monthly Forecast into executable Weekly Schedule; (3) creating technology for running Planning Scenarios with ability to compare scenarios for optimized field execution; (4) improving system reliability of Work Planned jobs: increasing forecast accuracy of downstream processes (ie. material); and (5) building Dashboards and reports to provide visibility and help management maintain process control. Alternatives considered: (1) Purchase commercially available system. This option was not selected as a single all-encompassing system does not link the Annual Forecasting to execution. Products reviewed included Prometheus. (2) Microsoft Excel based solution, extending the Microsoft excel based solution was not selected as it does not provide the level of data integration for controlling large number of forecasted work items. (3) Development of a system that integrates with our SAP investment. This option was not selected as it does not align to expected value delivery timeline. (4) Purchase a SaaS solution to enable planning & forecasting with integration to our SAP work management system. The fourth alternative was selected because it aligns to the expected value delivery timeline and meets the functional requirements.	2024-06-04	2025-12-28	-0.98	922,440	3,584,900	ROM	-	-	-	-	-	-	-	84,798	-	-	77,762	1,488	5,548	-
336	2026	30% ROW Adjustment - Electric & Gas Shared	Software(Intangible)	Electric & Gas Shared	This is for the 20% ROW Adjustment for IT projects.							(75,591)	-	(5,009)	(19,147)	(9,439)	(8,213)	(1,152)	-	-	-	-	-	-	-
337	SUBTOTAL	2026 Electric & Gas Shared										560,824	-	33,753	180,112	148,664	41,188	148,957	573,577	-	2,900	509,725	26,105	26,867	-
338	2026	Application Currency-Gas-Capital	Software(Intangible)	Gas	The Gas Engineering and Operations initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Gas Engineering and Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risks; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes. Applications within the Gas Engineering and Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure; (2) an increased number of incidents; (3) paying increased support costs; and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	37,000	-	ROM	16,500	-	-	25,000	-	1,000	10,250	-	-	-	-	-	-	-
339	2026	Application Currency-Gas-O&M	Software(Intangible)	Gas	The Gas Engineering and Operations initiative will utilize O&M funding to keep applications current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Gas Engineering and Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3)addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risks; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; (4)testing the upgraded software; and (5)updating documentation related to the integration changes. Applications within the Gas Engineering and Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on (1) maintaining an optimal balance between keeping the application current and risking failure, (2)an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	257,147	ROM	-	-	-	-	-	-	-	356,944	31,815	-	210,401	-	14,728	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHB-5)
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Witness: Shibakar
Date: December 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/ P RODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
340	2026	Compression Air Permit And Compliance Digitalization	Software(intangible)	Gas	The project modernizes and expands the use of software and digital forms in support of station air permits and code compliance at Gas Compression facilities. The current process around air permits and compliance for Gas Compression is cumbersome, largely paper based, and is made up of multiple disconnected systems. This leads to poor visibility, process inefficiency and waste, re-work, equipment risk, and human error. No project provides value to the Company through (1) increased productivity by direct data entry in the field, (2) improved quality through increased accuracy of updates completed at the time and place of the work, (3) elimination of the need to enter data into multiple disconnected systems, and (4) improved safety through access to real-time information used at work sites rather than printed procedures and forms. The scope of the project includes: (1) Merging the existing air permit and compliance tools into a single solution, (2) purchasing licenses to add Gas Compression users to the company's existing mobile work management software, and (3) configuring changes in SAP and the mobile work management software to replace the paper-dependent process with the ability to access and update maintenance, operations, and safety information for Gas Compression. Alternatives considered include: (1) Utilize an SAP work management mobile solution. An SAP work management solution was not selected since it is an unproven solution at the Company and would require additional project and support costs. (2) Continue with the manual paper-based process and forms. Continuing with the manual paper-based process and forms was not selected because it would not eliminate the identified process waste, re-work, and human error. (3) Costs rise the existing Electronic Shift Operations Management System (eSOMS) mobile application to add work management functions. A customized mobile application was not chosen because it would require additional project cost and an ongoing support budget for a custom solution that the product was not intended to support. (4) Adopt a cloud based SAAS solution. This option was not selected as it was a high cost option. (5) Utilize the existing Service Suite solution currently deployed for Gas and Electric Distribution. The Service Suite solution was selected because it is both an internally developed solution at the Company and provides the required mobility and digital benefits at a lower cost than other options.	2026-01-06	2027-12-31	-1.00	766,138	109,926	ROM	462,216	-	1,300	300,000	-	21,000	139,755	45,726	-	-	42,735	-	-	2,991	-
341	2026	Gas Distribution Probabilistic Risk Model	Software(intangible)	Gas	The project will implement a risk analysis model for comprehensive predictive risk analysis and model regression distribution pipeline assets. Relative risk models are unit-less measures of risk derived from input information using qualitative data and ordinal scales to produce "risk index" scoring. In simple terms, the relative risk model does not provide true statistical measures. The risk assessment used in the current model provides a score for likelihood, consequence, and risk of one asset only in comparison to other scores. While the outputs provide a sense of relative risk when comparing one pipeline with another, the scores do not provide quantitative scores for probability, frequency, or expected loss of events. Although pipeline operators commonly use relative risk models, the quality of the relative risk ranking relies on subject matter expert inputs, human inferences, and opinions. Completion of this project will provide value to both the Company and its customers. The project scope encompasses the implementation of a probabilistic risk model for gas distribution. Alternatives considered for the project include: (1) Implement a custom, Excel-based probabilistic risk model through a consulting effort. This alternative was not selected because although the effort minimizes the IT cost of the project, the model requires the creation of secondary data sources, leading to multiple "sources of truth". (2) Implement a custom built probabilistic risk model. This alternative was not selected because the custom built solution is analyzed are not mature and have not been widely tested with transmission operators.	2025-10-01	2027-10-31	-1.00	4,510,700	41,870	ROM	1,038,640	-	-	420,000	350,000	53,900	215,740	7,961	-	-	7,440	-	521	-
342	2026	Product Family Enhancements-Gas-Capital	Software(intangible)	Gas	The Gas Engineering and Operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Gas Engineering and Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor opex and work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Gas Engineering and Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating business orientation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering and Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this fund ingare governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using a range of benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	1,523,409	181,738		1,523,409	-	14,393	812,355	196,140	70,000	430,500	181,738	-	-	121,098	15,000	45,640	-
343	2026	Product Family Enhancements-Gas-O&M	Software(intangible)	Gas	The Gas Engineering and Operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for a make-effort software application change that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Gas Engineering and Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Gas Engineering and Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering and Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this fund ingare governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using a range of benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	-	239,401		-	-	-	-	-	-	-	239,401	-	-	4,242	202,019	13,256	19,884	-
344	2026	Replacement for Gas Automated Meter Reading (AMR) Technology	Software(intangible)	Gas	This project will replace Iron Field Collection Systems (ICS) and Iron Mobile with the newest Iron Software as a Service (SaaS) Temetra along with replacing Iron Mobile with Temetra Mobile for Gas AMR meters. This will allow the Company to leverage new cloud capabilities and align with the Company's Cloud strategy. The Company is using ICS and ICS mobile to gather gas meter reads. The vendor is replacing these systems with new Cloud software called Temetra and Temetra Mobile due to ICS and Iron Mobile being end of life December 2026. The software migration is necessary to maintain vendor support. Latest security patches, bug fixes, latest functionality while avoiding security, stability, and reliability risks for the Company. Moving to Iron Temetra will ensure no gas meter reading disruption and continued integration with existing gas communication modules and Iron Security Manager. The project adds value by: (1) continuing to collect accurate and timely gas meter reads; (2) removing the risk of being on unsupported versions; (3) utilizing the latest functionality such as retrieving historical data, and pulling reads on demand; (4) seamlessly getting up to date security patches; (5) and reducing ongoing networking equipment replacement and upgrade costs. Included in the implementation is: (1) configuring and deploying Temetra and Temetra Mobile; (2) migrating data; (3) integrating to Iron Enterprise Edition (EE); from Security Manager (SM); gas AMR PI Historian and Data Lake; (5) integrating to Iron Data Collector (MC Itg); (5) testing the software, data migrations and integrations; (6) educating and increasing the skills of the employees to leverage the new cloud services; (7); and decommissioning ICS and Iron Mobile and the on-premise databases and servers. Alternatives considered included: (1) continuing to use the ICS application and Iron Mobile without vendor support. This alternative was not selected because it would add gas meter reading data collection which would negatively impact critical customer billing operations. It would also decouple from the Iron security infrastructure that the other business critical Iron applications use, creating more expense and complexity in the technology environment. (2) Replace the platform with a different mobile gas reading application, which would also require the Company to replace the 1.2 million gas communication modules on the meters. Replacing ICS would require the application business owners to undertake a large initiative requiring multiple years to implement and a multi-team effort from start to finish. It would also increase the amount of technology needed to be supported and add cost to support as it would be a standalone product. (3) Move to Iron's Cloud technology (Temetra and Temetra Mobile). This option best suits customers and the Company's needs for the future as it offers new functionality while maintaining the system integrated into the Iron Security infrastructure and with the other Iron software products in use at the Company.	2026-01-12	2026-10-15	-1.00	1,027,600	112,086	ROM	1,027,600	803,282	-	108,680	57,830	7,608	50,210	112,086	-	-	100,320	4,744	7,022	-
345	2026	Tracking & Traceability	Software(intangible)	Gas	Tracking and Traceability is a project driven from proposed regulatory rules that will require utilities to map new and replacement installations with tracking and traceability data for plastic pipe, fittings, and fusions for the lifetime of the asset. The Company does not currently have a Tracking and Traceability program that will meet PHMSA proposed requirements (PHMSA-2014-0086); also known as the Plastic Pipe Rule. Tracking and traceability refers to the collection of information that provides manufacturing, material type, and location information for pipe and components. PHMSA defines the terms. The project will develop a sustainable Tracking and Traceability program that will meet PHMSA requirements (PHMSA-2014-0086) which address the proposed tracking and traceability requirements. The project adds value by capturing traceability data via barcode readers and location tracking information via Global Positioning System (GPS) equipment to improve the quality of data and assist the Company in determining future scopes of work in the event of any component manufacture recalls. The scope of work will include: (1) changes in SAP Supply Chain processes to capture the required barcode information for all plastic components used in gas distribution and service lines; (2) changes in SAP Work Management processes to account for capturing barcode information as part of material components added to work orders, capturing fusion information from work order completion and capturing GPS coordinates from work order completion; (3) changes in GIS to capture GPS coordinates of plastic components and GPS coordinates of component fusions; (4) building of a repository for tracking and traceability reporting and analysis; (5) purchasing barcode reading equipment for crewrooms and gas distribution trucks; and (6) purchasing of GPS locating equipment to capture coordinates. Alternatives considered: (1) The do nothing alternative, which was not selected because it would expose the company to significant legal and financial risk resulting from non-compliance. (2) Internally develop digital technology supporting the tracking & traceability standards included in the PHMSA-2014-0086 plastic pipe rule. The second alternative is being pursued by the Company.	2025-01-01	2027-06-30	0.00	14,864,950	2,488,640	ROM	7,177,830	-	4,081,350	1,750,000	324,000	143,780	1,068,100	908,350	-	-	395,000	80,000	33,250	-
346	2026	30% ROW Adjustment - Gas	Software(intangible)	Gas	This is for the 20% ROW Adjustment for IT projects.							(1,598,775)	(160,656)	(802,680)	(516,736)	(146,166)	(45,518)	(196,811)	-	-	-	-	-	-	-
347	SUBTOTAL	2026 Gas										9,998,609	642,626	3,225,153	2,879,299	781,616	252,070	1,617,744	1,352,105	31,185	4,248	1,079,013	110,000	124,086	-
348	2026	ARP-Infoblox Refresh	Network	IT-Digital Foundation	This project will replace the three legacy core components, Domain Name System (When Infoblox Assets that are used to support customer interactions and ensure the stability of technology for business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with Security updates. Consumers Energy also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. The value of this program includes: (1) enabling the Company to efficiently manage and control their network; and (2) providing Domain Name System. The scope of this project includes the replacement of NIOS, DDI and IPAM assets on a six-7-year refresh cycle. The alternative considered was to continue operating existing Infoblox equipment past the vendor's end of support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes. The alternative to replace the existing Infoblox equipment with the latest hardware and software provided by the vendor was selected to avoid these risks and continue a regular refresh cycle.	2026-01-01	2026-12-31	-1.00	197,440	32,100		99,235	-	66,315	14,469	7,235	1,519	5,788	11,943	-	-	5,581	5,581	781	-
349	2026	ARP-Local Area Network	Network	IT-Digital Foundation	This project will upgrade the Company's entire LAN and a significant portion of the Wireless Local Area Network (WLAN). At some Company locations, LAN equipment has been in service since 2011. The project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor supported, thereby ensuring support for bug fixes, security updates, and enhanced features; (5) providing consistent wireless coverage across all Company locations; (6) increasing user productivity through higher performing wireless network, which increases the productivity and efficiency of office and field employees. The project scope includes: (1) refreshing the LAN equipment and software across all Company sites; (2) identifying the required features for the new equipment; (3) implementing the new equipment according to industry best practices; (4) replacing wireless network with upgraded infrastructure and verifying wireless coverage is as expected; and (5) collecting wireless survey data for all Company locations in order to design improved wireless network coverage. The alternative considered was to continue operating on the existing platform past the vendors end-of-support date. The vendor support period ended in May of 2016, and paying for extended support is not an option offered by the vendor. The risk inherent in not refreshing the platform is a lack of vendor support resulting in an absence of software bug fixes, security updates, and break fixes. The Company chose to replace the existing equipment with the latest hardware and software available, following a five-year refresh cycle.	2026-01-01	2026-12-31	-1.00	511,110	47,370		246,508	-	180,863	48,230	12,058	1,500	3,858	17,625	-	1,302	12,278	2,977	1,068	-
350	2026	ARP-Radio	Network	IT-Digital Foundation	This project will refresh hardware to include; 800Mhz Radios and infrastructure, cellular modems, plant radios and systems, cellular amplification devices, vehicle consoles in service trucks, other communications equipment, and associated test equipment. 800Mhz, mobile, and portable radios, Plant radio systems, and Cellular modems support core business functions. It's safety communications, and rapid response for restoration of customers service and critical infrastructure. Company radios must be refreshed on a scheduled basis or risk exceeding life expectancy and failing or becoming obsolete. The refresh of this equipment in a proactive manner is critical to providing service to customers. If these units are not refreshed, the increased risk of unit failure would result in interruptions to timely and consistent communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, with the risk to life safety. This project creates value for customers and the Company by: (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk workspaces by replacing equipment with units that contain intrinsically safe batteries; (5) supporting continuous improvement and training by replacing equipment that is capable of recording recordings; and (6) meeting rule compliance with NERC regulatory requirements by maintaining critical radio infrastructure. The project scope consists of: (1) scheduled replacement of radios, modems, and consoles; and (2) installing additional radios modems and consoles as is to satisfy growth requirements; and (3) scheduled replacement of out of date cellular and radio boosters. The alternatives considered was included: (1) Replace the existing units with units from other manufacturers and modern manufacturers; (2) purchase new radio subscriber units from existing manufacturers.	2026-01-01	2026-12-31	-1.00	2,508,316	221,783		1,209,761	-	903,172	43,588	226,640	18,917	17,435	82,519	-	-	70,090	6,754	4,861	813	-
351	2026	Application Currency-IT/Digital Foundation-Application Platforms-Capital	New Computers / Hardware	IT/Digital Foundation	The Application Platforms initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive security updates and upgrades to address defects, patch against system threats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades in the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impact stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regular sprontized based on considerations to their include application security, security number of versions behind the current available versions security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database; (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Application Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of these efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining a balanced balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) pay ing increased support costs, and (4) preventing enhancements from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and functioning properly. Without these upgrades, the Company will further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	237,591	209,506	ROM	98,638	-	-	40,105	-	2,807	15,721	77,950	-	-	72,851	-	5,100	-
352	2026	ARP-Collaboration	New Computers / Hardware	IT-Digital Foundation	This project will refresh the Company's obsolete or out-of-date audio, visual, telephony and other communication collaborative tools and equipment. When Collaboration Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates. The project scope consists of: (1) annually replacing aging collaboration assets; and (2) installing new collaboration assets to account for evolving business requirements. The following alternatives were considered: (1) refresh visual assets and a portion of the audio assets; (2) refresh a portion of the audio assets only; and (3) refresh visual assets only.	2026-01-01	2026-12-31	-1.00	1,754,542	222,451		551,458	-	468,384	51,199	26,658	5,017	-	82,767	-	-	9,636	67,716	5,415	-
353	2026	ARP-Core Network	New Computers / Hardware	IT-Digital Foundation	This project will refresh the Data Center network equipment. When network assets that are used to support customer interactions and ensure the stability of mission critical business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; and (4) standardizing network infrastructure across Data Centers. The project scope includes the replacement of all core network devices with next generation devices. The alternative considered was to continue running in the current state or defray the replacement of network devices and accept the risk of further business and customer impact when more equipment failures occur.	2026-01-01	2021-12-31	-1.00	539,800	34,000		169,619	-	157,150	6,286	3,148	1,823	1,257	12,650	-	3,892	3,721	4,465	573	-
354	2026	ARP-Field Device Asset Management (FDAM)	New Computers / Hardware	IT-Digital Foundation	This project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failures, security patches, and software compatibility. When Field Device Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with Security updates as equipment becomes obsolete. This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing field devices prior to increased hardware failures; and (2) allowing field workers to complete their job tasks. The project scope consists of replacing field devices according to the four-year refresh cycle. The alternatives considered were to: (1) extend the replacement cycle from four years to five years for field devices; and (2) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the assets that need refreshing in future years based on the number of devices that were not replaced during the four-year refresh cycle; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the five-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company elected a five-year refresh cycle to alleviate these concerns.	2026-01-01	2026-12-31	-1.00	7,678,471	5,000		2,413,148	-	2,351,388	42,242	-	2,957	16,897	1,860	-	1,860	-	-	-	-
355	2026	ARP-Operational Technology Support Gas	New Computers / Hardware	IT-Digital Foundation	The ARP- OT Support Gas project will replace dated and obsolete servers on a rotating 5-year refresh schedule. When OT Assets that are used to support customer interactions and ensure the stability of technology for business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with Security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value by maintaining the currency of the Company. The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity for expanding business requirements. The alternatives considered include: (1) continue to operate hardware beyond a five-year refresh cycle and defer/ramp hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five-year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety for customers. The Company chose the alternative to refresh the hardware based on a five-year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure that supports systems such as Gas SCADA and Gas Compression control systems.	2026-01-01	2026-12-31	-1.00	2,765,844	454,194		2,765,844	-	2,214,189	269,960	-	18,897	262,848	454,194	104,814	349,380	-	-	-	-
356	2026	ARP-Printer Asset Management (PAM)	New Computers / Hardware	IT-Digital Foundation	This project will replace and install select printers, plotters, and multi-function printing devices based on printer replacement assessments and a five-year refresh cycle. Printer service and usage history is evaluated and a determination is made if a printer can be repurposed instead of ordering a new one. When Printer Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with firmware and security updates. This project creates value for the Company by: (1) improving the dependability of these printer devices for employees. The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle. The alternatives considered for the project included looking at refresh cycles from three to seven years as well as running the assets to failure. The selection of a five-year cycle was determined to be the best solution since anything less than five years would increase the likelihood of unneeded expense for replacement of assets that were still in good operating condition. Anything greater than five years is assessed monthly to ensure it is not run-to-failure, including running the asset to failure, resulting in additional expenses for maintenance of the equipment and downtime, negatively affecting employee productivity. The Company assesses the printer fleet based on years of active service, service history, printer usage data, and the number of users within a facility. Based on these factors, the Company either decommissions, repurposes, leases in place, or refreshes the printers.	2026-01-01	2026-12-31	-1.00	130,839	5,000		46,128	-	40,480	471	-	33	189	1,860	-	1,860	-	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
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Date: December 2024

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	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAP ITALS PENDING FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
357	2026	AFP-Server and Storage	New Computers / Hardware	IT Digital Foundation	This project will replace or augment server and storage infrastructure for the Company. When Server and Storage Hardware Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support, and can be more challenging to keep current with Security updates. This project creates value for the Company through: (1) improved stability and availability of business-critical applications by proactively replacing server and storage hardware assets prior to the likelihood of increasing hardware failures; and (2) ensuring that adequate resources are available to support application demands after five to seven years of actual use. The scope of this programencompasses es: (1) replacement of server and storage hardware assets; and (2) installation of additional new computers and storage capacity to account for evolving business requirements. The alternatives considered were to purchase extended maintenance, move some of these assets to the cloud with the Digital -Hybrid Cloud and Data Center Migration project, or to replace the assets in the current cycle. The option to purchase extended maintenance was not selected because a full support would not be offered after seven years, and maintenance costs would increase. The preferred option is to move so me of these assets to the cloud in the Digital Hybrid Cloud and Data Center Migration project while refreshing the remainder using the five- to seven-year cycle as it is the most cost-effective option. If the Digital-Hybrid Cloud and Data Center Migration project is not expressed as part of this rate case, the Company plans to continue to refresh these critical technologies at the current level based on a five- to seven-year refresh cycle to mitigate the risk of failure.	2026-01-01	2026-12-31	-1.00	2,302,530	683,050		715,681	-	603,300	78,575	-	5,500	36,302	179,727	150,224	-	-	42,788	3,721	2,995	-
358	2026	ARP-Workstation Asset Management (WAM)	New Computers / Hardware	IT Digital Foundation	This project will replace and install new desktops, laptops, and tablets on a five-year refresh cycle based on industry standards, hardware failures, security patches, and software compatibility. Monitors will be replaced every eight years based on Company data related to historical failure rates. When Workstation Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle. This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing business partners to complete their job tasks. The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources. The alternatives considered were to: (1) extend the replacement cycle from five years to six years; (2) extend the replacement cycle only on desktops from four years to five years; and (3) use outdated equipment. The Company did not select these options because it: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the ARP infrastructure costs that were not replaced during the four year refresh cycle; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle for desktops, laptops, and tablets, and an eight-year cycle for monitors to alleviate these concerns.	2026-01-01	2026-12-31	-1.00	6,070,278	60,792		1,907,888	-	1,813,670	44,610	26,797	4,996	17,844	22,619	-	-	21,470	1,073	-	75	-
359	2026	Operational Technology (OT) Datacenter Migration	New Computers / Hardware	IT Digital Foundation	The OT environment consists of systems supporting the control and monitoring of electric grid, electric generation, gas compression and natural gas pipeline. These systems are critical for safe and reliable natural gas and electric delivery. The OT Datacenter Migration project enhances the Company's capabilities by re-hosting to an enhanced datacenter at a vendor facility. The Company's current datacenter for the OT environment needs modernization and relocation from the Parnall Data Center. The current location is not the preferred location to house servers and systems critical to the control of the Electric Grid or Gas Pipeline due to the close proximity to a railway system. The climate conditions in the current OT datacenter are aging and have had faults resulting in unplanned shutdowns. The location of the datacenter in the basement of the Parnall building is nearby to the main water piping for the building. There have been instances of water infiltration in the past. This project creates value for the Company by significantly strengthening capabilities through: (1) mitigating legacy physical and location risks at the current Parnall OT infrastructure is a modern, highly secured environment with redundancy in climate conditions; and (2) better datacenter facilities support with a guarantee of redundant power. The scope of the project includes: (1) migration of the OT environment from the Parnall Data Center to a co-located vendor data center; (2) re-validation of the OT Production and Disaster Recovery procedures once migration is completed; (3) migration of IT systems required for supporting the OT environment; and (4) decommission the existing OT environment from the Parnall location. The Company performed an analysis of alternatives to expand capabilities as well as address constraints and risks: (1) Remain at the current Parnall Data Center; (2) migrate OT environments to the Cloud; and (3) relocate to a third-party co-location facility. Current state/best practice does not recommend migration of OT environments to the cloud. The co-location vendor provides the building, cooling, power, and physical security the Company asks for its servers, storage, and other computing and networking equipment at the current Parnall location. Based on the analysis, the Company decided to implement the third alternative.	2026-06-30	2027-12-01	-1.00	7,749,620	4,479,267	ROM	2,118,530	157,150	1,574,663	94,290	157,130	17,601	160,676	859,768	-	-	-	111,620	202,777	22,008	523,363
360	2026	20% ROM Adjustment - IT/Digital Foundation	New Computers / Hardware	IT Digital Foundation	This is for the 20% ROM Adjustment for IT projects.							(446,028)	(31,430)	(314,959)	(26,879)	(31,430)	(4,082)	(35,279)	-	-	-	-	-	-	-
361	2026	Application Currency-IT/Digital Foundation-Application Platforms-O&M	Software(Intangible)	IT/ Digital Foundation	The Application Platforms initiative will utilize O&M funding to keep application s current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor support nat versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can lea ve a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through upgrades to the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version s, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application s oftware and respective databases; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software, and (5) updating documentation related to the integrations changes. Applications within the Application Platforms area are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for this application possible and forthcoming. The Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions n, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	289,604	ROM	-	-	-	-	-	-	-	107,687	-	-	-	100,642	-	7,045	-
362	2026	Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M	Software(Intangible)	IT/ Digital Foundation	The Infrastructure Platforms initiative will utilize O&M funding to keep application s current for security and reliability. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor support nat versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of application s through application currency upgrades in the Infrastructure Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The application upgrades in scope are regularly prioritized based on considerations that include application criticality, number of versions behind the current available version s, security and operational risk, operational impacts of performing the upgrade, ability to defer, and cost. The scope of upgrading these applications encompasses: (1) upgrading the application s oftware and respective databases; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software, and (5) updating documentation related to the integration changes. Applications within the Infrastructure Platforms area are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for this application possible and forthcoming. The Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions n, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	39,211	ROM	-	-	-	-	-	-	-	14,249	-	-	-	13,317	-	932	-
363	2026	Data & Analytics Platform Rationalization	Software(Intangible)	IT Digital Foundation	This project will optimize the Data & Analytics system landscape by creating connections, migrating data into Data Lake 2.0 (DL 2.0), and building visualizations from the data in DL 2.0. Following the enablement of DL 2.0, retirement of the IT Data & Analytics legacy systems including Teradata Data Lake (EDL), SAP Business Warehouse (BW), SAP Business Objects (BOBJ), Native HANA, the BW Portal, and SAP Business Objects Data Services (BODS) creates value by reducing the total cost of ownership associated with maintaining and supporting legacy systems. The IT Data & Analytics legacy systems (EDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BODS) are outdated, inefficient, and become significantly more expensive to maintain over time. Additionally, these systems are no longer meeting the business needs and require significant investments are needed to maintain and support them. This platform rationalization project creates value for the Company and its customers by reducing the total cost of ownership associated with maintaining and supporting legacy systems including licensing fees, maintenance costs, infrastructure, and support resources. The project scope includes: (1) the assessment of the existing Data & Analytics platforms including EDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BODS; (2) inventory of data and reports still being used by stakeholders; (3) determination of migration strategy; (4) data migration to the Azure Data Lake; (5) report migration to Power BI; (6) organization change management; and (7) the retirement/decommissioning of the legacy platforms and applications. Alternatives considered: (1) upgrade legacy systems in place (on-premise). This alternative was not selected because this is costly and misaligned with the Company's cloud strategy. (2) Lift and shift these on-premise systems to the cloud through the Hybrid Cloud Transformation Program. This alternative was not selected because it would duplicate the work being done as part of the DL 2.0 project and would not provide the same efficiencies that DL 2.0 introduces. The alternative to migrate all data sources to DL 2.0 and retire legacy systems was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.	2025-03-03	2026-08-14	0.15	10,002,200	1,660,500	ROM	1,057,148	31,430	-	88,963	889,638	6,223	41,101	305,735	-	-	-	18,585	185,848	1,302	-
364	2026	ISS Papyrus 2026 Upgrade	Software(Intangible)	IT Digital Foundation	This project will upgrade the Papyrus Objects suite of applications to the most recent version available per vendor recommendation. The ISS Papyrus applications critical to creating electronic and paper correspondence for customers, including bills and dunnings. The application will be at least 1 major upgrade revision behind by 2026. It's imperative our customers retain uninterrupted access to their paper bills, dunning notices and other communications delivered by ISS. If it also makes customer bills available for online viewing through the website and mobile apps. Without the upgrade, our vendors make no guarantee that any substantial patches or hot fixes impacting application reliability, capacity and security will be forthcoming. The upgrade will address these problems and challenges, as well bring ensure all other platform components comply with our company operational and security standards. The value of this project includes: (1) providing a more stable operation ne ed t by upgrading to the nex et recent version available; (2) maintaining the necessary vendor support; and (3) resolving tuning and stability issues with the vendors. The scope of the project is to upgrade the various license products that comprise the Papyrus Objects suite of applications. As this is an upgrade of an existing system, the alternative considered was to delay the upgrade and continue operating with the current version. This alternative was not chosen due to the risk of application stability and the inability to maintain cyber security patching.	2026-02-01	2026-10-01	-1.00	719,700	276,000	ROM	226,202	92,719	25,164	70,718	-	4,950	32,671	102,691	-	-	-	93,017	-	6,511	3,163
365	2026	Itron Enterprise Edition 2026 Upgrade	Software(Intangible)	IT Digital Foundation	This project will upgrade Itron Enterprise Edition (EE), which collects the reads from meters to ensure non-estimated bill accuracy. Itron Enterprise Edition (EE) is the Company's keystone application of the Advanced Metering Infrastructure (AMI), that provides the gas data. Included in this scope of work is the IT infrastructure introducing application instability, security and dependency risks to the utility, possibly negatively impacting critical customer electric and gas billing operations. It would also likely affect other business critical Itron applications such as creating more expense to support and no ability to leverage updated software capability. (2) Replacing EE/MDM would require the application business owners to undertake a new initiative mirroring the expense and effort that went into the multi-million dollar project responsible for setting up and leveraging this utility. (3) Perform nothing. This option is superior for both our customers and our Company because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Itron products.	2025-07-29	2026-06-09	-1.00	-	495,277	ROM	-	-	-	-	-	-	-	48,856	-	-	-	45,660	-	3,196	-
366	2026	Product Family Enhancements-Application Platforms Services-Capital	Software(Intangible)	IT/ Digital Foundation	The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements that benefit the IT organization s in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experiences; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary systems changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	955,650	305,850		303,361	-	-	172,834	31,430	14,298	81,798	113,797	-	-	-	85,164	21,189	7,645	-
367	2026	Product Family Enhancements-Application Platforms Services-O&M	Software(Intangible)	IT Digital Foundation	The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements that benefit the IT organization s in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experiences; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary systems changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	-	114,881		-	-	-	-	-	-	-	42,747	-	-	-	39,951	-	2,797	-
368	2026	Product Family Enhancements-Infrastructure Platforms Services-Capital	Software(Intangible)	IT Digital Foundation	The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software & hardware and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements that benefit the IT organization s in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experiences; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary systems changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	573,391	183,510		180,217	-	-	103,701	18,858	8,579	49,079	68,278	-	-	-	51,098	12,713	4,467	-
369	2026	Product Family Enhancements-Infrastructure Platforms Services-O&M	Software(Intangible)	IT Digital Foundation	The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements that benefit the IT organization s in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experiences; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary systems changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management. Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	-	332,011		-	-	-	-	-	-	-	120,642	-	-	-	112,749	-	7,892	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHR-5)
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Date: December 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
370	2026	SAP S/4HANA Implementation	Software(Intangible)	IT Digital Foundation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
371	2026	SAP Support Pack Upgrade 2026	Software(Intangible)	IT Digital Foundation	The SAP Support Pack Upgrade project is to maintain the currency levels of all SAP applications. This will ensure the applications are at versions levels that are supported by SAP, have the latest patches and bug fixes, and provide cross-application compatibility for our business partners. To continue to maintain SAP application version currency, across all applications, the support packs released by SAP must be routinely applied. Without maintaining application currency, the core business applications running on the SAP platform are at risk of losing vendor support, resulting in the inability to apply bug fixes and patches, including security patches, and maintain application interoperability and stability. The project will add value by: (1) maintaining supportability of SAP applications; (2) mitigating system security, stability and reliability risk by ensuring the applications are up-to-date with the most current patches and bug fixes released by SAP; and (3) ensuring ongoing cross-application compatibility. The scope of this project includes routine support pack upgrades to all SAP applications, which include: Enterprise Core Component (ECC), Customer Relationship Manager (CRM), Enterprise Portal, Process Orchestration (PO), Business Warehouse (BW), Business Objects (BOBJ), Data Services (DS), Solution Manager, Data Quality Manager (DQM), Graphical User Interface (GUI), Single Sign On (SSO), Systems Landscape Directory (SLD) and other related SAP applications. Alternatives considered include: (1) Divide the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) Migrate to SAP S/4HANA. This option was not selected, because a SAP S/4HANA is a multi-year project that is not expected to be completed by the year-end 2026. So an alternative approach is needed to perform the application upgrades and maintain currency in the meantime. (3) Balance the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimizing cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.	2026-02-01	2026-10-31	-1.00	-	1,086,557		-	-	-	-	-	-	-	364,849	-	-	369,018	-	25,831	-
372	2026	Software Platform Refresh	Software(Intangible)	IT Digital Foundation	The Software Platform Refresh project will upgrade server operating systems, hypervisors, databases and infrastructure platforms to retain low-cost vendor support. For systems that go beyond their normal manufacturer support ending, there will be increased support and maintenance fees of 20% to 100% above current support and maintenance depending on vendor. Completing this project allows the organization to (1) avoid high support costs; (2) provide for system security; and (3) be current to promote seamless interoperability among servers, application, and databases. Aging platforms are more susceptible to security vulnerabilities and pose a reasonable threat that could affect the business and customers. The project will add value for the Company by (1) avoiding costs for special maintenance agreements required at the end of normal manufacturer support; (2) ensuring stability and compliance with Information Security requirements; (3) improving data center environment stability; and (4) avoiding the need for high risk upgrades that cross multiple versions. The project scope includes: (1) upgrading operating systems and databases on servers that are near end of support with a given vendor; and (2) maintaining hypervisors and infrastructure platforms at the current version for stability and performance. A funding options matrix was developed to review the potential alternatives. The alternatives identified were: (1) Complete the full scope of the solution for $1 million in order to eliminate the need for ongoing extended support; (2) Reduce the scale of the solution, which requires $1.6 million in ongoing extended support; (3) Reduce the scale of the solution even further, which requires $2.4 million in ongoing extended support; (4) Do not complete a software platform refresh, which requires $1.3 million in ongoing extended support. Alternative 1 was selected as the most cost effective solution to ensure ongoing system stability, seamless integration, and mitigation of cyber-security risks without the significant cost of extended support necessary for end of life software systems.	2026-01-01	2026-12-31	-1.00	-	113,463		-	-	-	-	-	-	-	42,219	-	-	39,457	-	2,762	-
373	2026	20% ROM Adjustment - IT/Digital Foundation	Software(Intangible)	IT Digital Foundation	This is for the 20% ROM Adjustment for IT projects.																				
374	**SUBTOTAL**	**2026 IT/Digital Foundation**																							
375	2026	ARP-Cyber Security	Network	Security	This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions. When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates. This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations. The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a 3-5 year hardware lifecycle; and (2) performing application upgrades. As part of the review process, the alternatives considered were to: (1) upgrade or replace only those assets identified in the plan; (2) upgrade or replace a portion of the assets identified in the plan. Option 1 was not chosen because it ensures that only the security assets to avoid security risks, system vulnerabilities, and out-of-warranty repair costs. Option 2 was not chosen due to the security risk inherent with not replacing assets as per standard refreshcycles increased system vulnerabilities, and out-of-warranty repair costs.	2026-01-01	2026-12-31	-1.00	450,000	25,000		238,725	-	180,189	24,115	-	-	14,469	9,302	-	-	9,302	-	-	-
376	2026	ARP-Physical Security	New Computers / Hardware	Security	The ARP Physical Security, formerly known as Physical Security Asset Refresh, will enhance or replace physical security assets to provide improved visibility and incident resolution related to security concerns. The Company has several thousand physical security asset devices currently in use including security cameras, motion detectors, intrusion detection systems, and card access systems. Current limitations include the lack of integrated solutions for centralized management, situational awareness, real-time monitoring, compliance with regulations and guidelines, and faster response rates to emergencies and incidents. This could result in the increase of potential security vulnerabilities, associated penalties, and reputational damage. The value provided by completing the project is to: (1) maintain compliance with State and Federal Regulations; (2) reduce redundancies with lots of a need for multiple cameras and reducing gaps in functionality; and (3) optimize overall system performance. Included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) security cameras for monitoring capabilities; and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detection systems, and card access systems. Alternatives considered include: (1) not refreshing physical security assets, and (2) defer a portion of the refresh of physical security assets per an asset refresh cycle industry standard. Alternatives 1 and 2 were not selected due to the risk of security concerns, incident resolution, and the inability to meet FERC requirements. The alternative selected maintains compliance, reduces redundancies and gaps in functionality, and optimizes overall performance of physical security systems.	2026-01-01	2026-12-31	-1.00	2,474,862	12,626		777,378	-	408,119	49,031	181,866	136,363	-	4,698	-	-	2,902	1,488	307	-
377	2026	Security/OT Field Modernization	New Computers / Hardware	Security	This project will implement new infrastructure for accomplishing improved security in the field for OT assets. Gas and Electric technicians are using corporate laptops to manage critical OT infrastructure which does not follow cyber security best practices for managing critical infrastructure. The value of this project is deploying dedicated company OT laptops and associated OT infrastructure that can move between OT locations only and providing a secure environment. This project will procure and configure approximately 130 devices that will be used to manage critical OT infrastructure. The Company reviewed several options to mitigate cyber security risks inherent with the use of standard corporate laptops managing critical infrastructure. The alternatives considered are: (1) Continue utilizing existing profiles which using Corporate domain laptops with software installed; (2) Begin an outside vendor to design and implement a proposed infrastructure; (3) Considered completely disallowing use of all local access to critical systems; (4) Consider extending the OT network to remote Company locations; (5) Deploy a dedicated company OT laptop and OT communications circuits, which includes cellular connectivity. The dedicated OT laptop and communications circuits presented the best way to secure the critical infrastructure by limiting internet and e-mail access. Vendors and contractors could also utilize these approved dedicated systems for managing infrastructure they help support at Company locations. Based on the analysis performed, the Company chose to deploy a dedicated OT laptop and communications circuits.	2025-01-13	2026-06-01	-1.00	1,161,568	305,600	ROM	102,608	-	38,722	39,382	-	2,757	21,743	40,927	7,441	-	-	-	-	33,486
378	2026	30% ROM Adjustment - Security	New Computers / Hardware	Security	This is for the 20% ROM Adjustment for Security projects.							(30,581)	-	(7,364)	(7,876)	-	(551)	(4,549)	-	-	-	-	-	-	-
379	2026	Application Currency-Security Capital	Software(Intangible)	Security	This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades. The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Security digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protection; (3) address sing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; potential impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes. Application swithin Security are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing endusers from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	146,200	10,700		45,951	-	-	31,450	-	14,521	-	3,981	-	-	3,721	-	260	-
380	2026	Application Currency-Security O&M	Software(Intangible)	Security	This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrade The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities. Maintaining the appropriate versions of applications through application currency upgrades to the Security digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protection; (3) address sing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; potential impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software; (2) assessing any new functionality for value to the Company; (3) making necessary configuration changes; (4) testing the upgraded software; and (5) updating documentation related to the integration changes. Application swithin Security are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing endusers from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.	2026-01-01	2026-12-31	-1.00	-	160,339		-	-	-	-	-	-	-	134,082	-	-	125,310	-	8,772	-
381	2026	Business Continuity - Program Management Tool	Software(Intangible)	Security	The Business Continuity Program Management Tool is critical for successful and effective Business Continuity, Disaster Recovery, and Emergency Management Programs. The software tool will provide automation, enhance the company's incident management processes, establish critical linkages between departments and essential functions they support, and it will perform necessary analysis before, during, and after a disruption that allow for the efficient response to minimize downtime. The current business continuity and disaster recovery program management tool does not offer the capabilities to advance programmaturity and to foster a world class response to a business interruption. The current tool limits automation opportunities and has gaps in how it handles template enhancements, which results in the need for manual workarounds in order to prevent losing critical data. The lack of capability affects reporting, upstream/ downstream impact mapping, incident Command System (ICS) documentation automation, and user administration. This project will create value for the Company by: (1) maintaining the documentation that supports the recovery efforts of critical processes and associated essential functions that, if disrupted, would present significant impact to the Company and our customers; (2) limiting business and community impact while providing a critical energy service; (3) prioritization of the recovery of critical processes and resource allocation during a business continuity incident(s); (4) providing a consistent, organized and expedient response process; (5) an Incident Command System that is flexible to meet the needs of any incident, regardless of severity or scope; (6) providing a mechanism for identifying restorations gaps between critical business processes and IT recovery capabilities; (6) reducing or eliminating human error and waste; and (7) improved and more efficient user experience. The project scope includes: (1) Framework for the development and maintenance of Business Continuity, System Application and Recovery Plans, Incident Command System, and Disaster Recovery Plans that are effective and easily accessible during an event; (2) automation for reporting to track status and to measure effectiveness and maturity of the program (Business Continuity, Emergency Management, Disaster Recovery Programs); (3) component that facilitates effective incident response and response efforts through incident management tools that utilize concepts from the Federal Emergency Management Agency (FEMA) National Incident Management System (NIMS); (4) program management tools to monitor required program deliverables; (5) template for developing and maintaining site hazard assessments; (6) dependency mapping of critical business processes and IT applications; and (7) integrated business impact analysis process. Alternatives considered include: (1) continue to use its fragmented current Disaster Recovery to ols. This alternative was not selected because it currently do es not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. (2) Revert back to manual processes. This alternative was also not selected because the manual process is time consuming, leads to human struggle and duplicative work. A previous KPMG Audit of the Business Continuity Program indicated the need for interdependency mapping and a software tool is the best way to accomplish this. (3) Implement a best-in-class Cloud Software as a Service (SaaS) solution. This alternative was selected because there are better SaaS solutions that fit the needs outlined above. The final application will be determined after a Request For Proposal is issued and a vendor is selected in the project plan phase.	2026-05-02	2027-03-02	-1.00	-	103,797	ROM	-	-	-	-	-	-	-	39,710	-	-	27,248	9,864	2,598	-
382	2026	Enhancements-Security Capital	Software(Intangible)	Security	This initiative will use Capital funding to make enhancements to existing technology and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements in accordance with accounting rules. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for this fund ingare governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	776,088	153,816		248,938	88,189	7,695	58,245	70,092	19,783	-	57,230	-	-	37,668	19,151	411	-
383	2026	Enhancements-Security O&M	Software(Intangible)	Security	This initiative will use O&M funding to make enhancements to existing technology and to address requests generated by changing business requirements. As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas. Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company. The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance. Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for this fund ingare governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software technology changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.	2026-01-01	2026-12-31	-1.00	-	319,297		-	-	-	-	-	-	-	118,810	4,580	-	109,535	2,655	2,040	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Synopsis Containing Descriptions, Scope, Benefits, Implementation Dates and Detailed Costs of Actual and Projected Gas & Common Capital Expenditures and O&M Expenses
For the years 2023, 2024, 2025 and 2026
Information Technology Department

REDACTED

Case No.: U-21806
Exhibit No.: A-20 (SHB-5)
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Witness: SHBaker
Date: December 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)
	SPEND YEAR	PROJECT NAME	FERC CATEGORY	BUSINESS CATEGORY/ PRODUCT LINE	PROJECT SYNOPSES	PROJECT START DATE	PROJECT END DATE	COST/ BENEFIT RATIO	TOTAL COMPANY EXPECTED PROJECT CAPITAL COSTS	TOTAL COMPANY EXPECTED PROJECT O&M COSTS	ESTIMATE TYPE	GAS PORTION CAPITALSPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS	GAS PORTION O&M SPEND FOR APPLICABLE YEAR	SOFTWARE COSTS-GAS	MATERIAL COSTS-GAS	LABOR COSTS-GAS	CONTRACTOR COSTS-GAS	NON-LABOR OVERHEAD-GAS	NON-LABOR OTHER-GAS
384	2026	Forward Web Proxy Services	Software(intangible)	Security	The project will replace the current web proxy service platform with a new platform. A web proxy service is a type of proxy server that sits between a client and the internet. It acts as an intermediary that evaluates, modifies, and forwards the client. The Company currently leverages an existing vendor platform for web proxy services that has been in existence since 2021. Since the implementation of the platform, is has caused ongoing operational issues and elevated web filtering and connectivity. When there is a degradation of service, company employees and contractors are unable to access internet or cloud-based resources. As the company continues its cloud and SAAS journey, it is imperative to provide consistent access and communication, while still protecting the company from cyber threats. This project creates value for the Company by (1) increasing service reliability for employees and contractors to internet and cloud-based resources; (2) utilize technology to enable the Company to handle all types of different workloads from varying geographic locations and is highly available; (3) using a mature and scalable web proxy service provider; and (4) providing Zero Trust by continuously verifying every connection request. The project scope includes: (1) replacing the current web proxy services solution and implementing a new system; (2) replacing physical web proxy hardware; and (3) potentially changing SAAS cloud vendors. The Security team did extensive research on alternative web proxy services solutions. Alternatives considered include: (1) continue to use and maintain the current web proxy services platform. This alternative was not chosen due to the consistent operational issues with the platform that make it unreliable. The result of an unreliable system means that employees and contractors are unable to access business critical services such as email, Teams, ServiceNow, SharePoint Online; (2) Route all internet traffic through the Company's corporate data center. This alternative wasn't chosen because the capabilities of firewall cannot as effective in stopping sophisticated cyber-attacks as using a web proxy service; (3) replace current system with modern vendor platform for web proxy services. The option that was chosen is to replace the current solution with a new system. This option was chosen because it offers additional features such as browser isolation (the ability to contain web pages so that the web page can't affect the client we illustration) and sandboxing (a way to safely execute malicious applications without impacting the Company's network). As part of the evaluation the Company reassessed based on outside advisors and industry trend analysis, focusing on the ability to execute and the vendor's company strategy.	2026-01-15	2027-12-30	-1.00	4,481,532	882,770	ROM	1,418,146	1,253,356	-	15,715	50,218	1,100	88,086	179,960	163,836	-	3,163	11,906	1,055	-
385	2026	Physical Access Management and Alarm Response	Software(intangible)	Security	The project will replace the Company's Physical Access Management System to establish a centralized platform that manages user identities, authenticates users, authorizes access, and audits user activities. The intent of this project is to consolidate and modernize the Company's physical security systems that will enable enhanced security monitoring to prevent unauthorized entry into sensitive corporate areas while providing increased flexibility to the Company's valued employees and contractors. The Company's Security Fusion Center (the Fusion Center) is the Company's combined physical and cyber security operations center(s) experiencing operational issues with the current physical access management system. The installation is out of date and causes inconsistent behavior when given tasks by automations within the Company's Identity Management solution. Frequent issues have been reported related to frozen jobs in the Company's existing access management solution due to the current system's database. This results in significant waste in the form of (1) waiting, the business partner is waiting much longer than they should have to for the system to process their request as un-freezing job is a manual process; (2) lost productivity, that waiting can cause for the business partner as it can either prevent them from accessing sites they need, or slow them down unnecessarily while they work with others to be escorted; (3) rework, because frozen jobs don't always run correctly when unfrozen, meaning the business partner has to resubmit their request and/or Identity Operations has to do additional work to satisfy the original request; and (4) alarms can cause a frozen state that impact system stability and reduces security while bys a result. Not moving to new technology also carries a growing risk of outright system failure which could result in unauthorized physical access and/or impact the Company's ability to effectively function. The current installation of the physical access management system and the Company's current card readers do not support next generation physical access control methods, such as digital ID. This prevents the Company from adopting new methods and practices that can lower costs and improve control and responsiveness. All employees, contractors, staff, and visitors are impacted by the problem. This project creates value for the Company by: (1) developing an alarm and event monitoring system, which will enable seamless orchestration of system alarms and scenarios; (2) adding automation that will streamline remediation processes and technicians operate as for efficiency; (3) refining access revocation and badge access management to ensure only authorized personnel have entry privileges; (4) introducing new access control readers that will modernize the system, allowing for the use of mobile device badges for employees, contractors, and visitors, offering a more flexible and user-friendly experience for those entering the Company. Alternatives considered were: (1) Keeping the current physical access control system and processes as is. This alternative was not selected as the current platform is outdated, increasingly expensive to support, and does not include modern capabilities, such as digital IDs. It also does not reduce waste, cost, and it does not improve speed to delivery; (2) Developing a custom, in-house physical access control solution that includes modern capabilities, such as digital IDs. This option was not selected as the Company lacks the expertise to build such a solution. Custom-developed solutions have higher long-term, and generally result in significant waste, as well as lower speed to delivery; and (3) Implementing a new physical access control system that includes modern capabilities, such as digital IDs, that reduces waste and cost and improves speed to delivery. There are vendors in the market that specialize in physical access control systems that offer proven capabilities the Company is looking to implement. This option was selected as it will allow the Company to meet its objectives of fewer waste, lower cost, improved speed to delivery, by implementing digital IDs and enabling tighter integration between the physical access control system and the Company's other security platforms.	2026-01-15	2027-12-01	-1.00	6,335,145	1,205,203	ROM	1,036,138	473,807	355, 159	35,359	70,718	7,425	73,870	122,022	-	-	114,039	-	7,983	-
386	2026	Saviynt Enterprise Identity Governance and Access (EIGA) implementation	Software(intangible)	Security	The project will implement Saviynt EIGA module, consolidate Identity Access Management (IAM) functionality into Saviynt, and retire the Identity Manager application. By implementing the new solution, the Company will optimize IAM functionality, eliminate complexity, and reduce support costs. In addition, the project will integrate the OT network with an IAM solution that will allow for automated management of users and entitlements in the OT Active Directory domains and applications. The current version of Access Now reached end-of-life in December 2022, with support discontinued in January 2023. The application has numerous custom workflows and integrations, requiring professional services for ongoing use and changes. It lacks proper data analytics and reporting, posing risks such as inability to fix critical defects, software incompatibility, compliance issues, increased costs, and degraded performance. The Company uses multiple IAM tools, each performing critical functions, leading to numerous required interfaces and customizations. While beneficial for end users, these integrations increase the risk of system failure, higher support costs, multiple subscriptions, infrastructure and maintenance costs, and more expensive upgrades. The current solution utilizes SAP HR batch file processes that introduce failure points, delays, and data integrity issues. Failures in these processes can prevent new or transferred employees from accessing necessary systems, leading to operational disruptions and potential compliance risks due to inappropriate access retention. This project provides value by: (1) Consolidating multiple IAM platforms through the implementation of the Saviynt Enterprise IGA Module, reducing complexity and support costs; (2) Decreasing complexity and enhancing efficiency by reducing interfaces between multiple identity tools; (3) Improving the end-user experience and reducing human struggle with access requests through a new, intuitive portal design; (4) minimizing custom code and focusing on configurations only by utilizing out-of-the-box functionality; and (5) Streamlining employee data processing with the implementation of an HR interface. This project scope includes: (1) Implementing the Saviynt EIGA module to consolidate IAM platforms; (2) Standardizing processes by removing customized code and using out-of-the-box functionality; (3) Replacing and improving access system; (4) Addressing issues with aging applications, multiple IAM platforms, integration challenges, and antiquated HR processing. Alternatives considered include: (1) Implementing hot fixes to Access Now version 8.1.5 to ensure support through mid-2023; (2) Upgrading the application to current supported version, excluding the new web portal but will including new application functionality; (3) Remaining on current version that will be unsupported as of January 2023, requiring vendor professional services for any break / fix. Patches and enhancements may potentially introduce additional risk of version instability; (4) Implementing IAM functions in Saviynt platform to manage access requests, including Active Directory, SAP, SAP HR, disconnected systems, and existing API integrations. The alternative selected was implementing the new Saviynt system, eliminating AccessNow software.	2023-11-27	2024-06-30	-1.00	5,913,132	710,912		297,498	-	15, 715	44,379	188,580	15,647	33,169	22,454	-	-	20,985	-	1,469	-
387	2026	Security Threat Intelligence Tool	Software(intangible)	Security	This project will implement a threat intelligence application that will actively assess physical and cyber threats in the environment, visually display historical and active threat data for situational awareness and provide alerts to employees based on location of the threat. This information will allow the Company's combined physical and cyber security operations center (Fusion Center) to alert employees who are in the proximity of a physical threat on the risks they may face, help inform decisions on hardening facility locations and alert employees of active cyber threats that are currently impacting other co mpanies. The ability to proactively alert employees of the threats will have a positive impact on Safety and Cyber Security for the Company by reducing response time to incidents and reduce the likelihood an employee will be physically injured. The Co mpany. This project creates value for the Company by: (1) implementing a threat intelligence tool that actively assess es threats in the environment; (2) Visually displaying historical and active threat data for situational awareness; and (3) Providing alerts to co workers based their location. Accurate and timely informatio n about threat actors and their tactics enables the team to proactively perform targeted investigation, containment, and remediation. The project scope includes: (1) Implementing a single threat intelligence application that will provide intel on both physical and cyber threats; (2) Integrating with the current security orchestration platform; and (3) Building automation to notify co workers of physical threats that are identified through intel provided in the application. Alternatives considered include: (1) Maintaining the Company's current security posture of manually gathering information on threats through social media, law enforcement and news reports. Continue to alert employees of active threats once they are noticed by Fusion Center employees. This alternative was not selected because the process to gather the data is completely manual and the data gathered can be outdated by up to a week. Role data can put co mpany assets and employees in dangerous situations. Using outdated information delays response time for co mpany crews and law enforcement to address the situation. (2) Expanding the Company's current manual notifications tool due to integrate security threat intelligence intel. This alternative was not selected due to the risk of delayed response time to receive threat notification fro mthe current vendor in comparison to other vendors in the market. (3) Building an in-house threat intelligence application to fulfill the security threat intel requirements. This alternative was not selected because developing security platforms of this type is not in the core competences of the Co mpany. The Company's resources don't have access to the wide range of threat data that other co mpanies leverage to develop a threat intelligence application. In addition, the cost to maintain an in-house application of this type would not be economically practical. (4) Implementing a threat intelligence application that meets the Company's security threat intelligence requirements. This alternative was selected.	2026-02-07	2027-08-02	-1.00	863,838	123,900	ROM	238,939	142,975	-	39,626	15 715	2,760	28,053	38,137	27,198	-	7,641	-	521	2,977
388	2026	30% ROM Adjustment - Security	Software(intangible)	Security	This is for the 30% ROM Adjustment for Security projects.							(538,958)	(374,039)	(71,182)	(24,386)	(72 346)	(5,161)	(38,002)	-	-	-	-	-	-
389	SUBTOTAL	2026 Security										3,779,609	1,584,900	926,722	304,819	551,894	194,483	217,040	771,212	203,156	-	401,312	45,065	25,416	36,463
390	TOTAL	2026																						

The Company fully plans to perform the projects included in the Information Technology cost projections, but the projections do not incorporate a specific confidence level. These costs were not projected using confidence levels. Rough Order Magnitude (ROM) estimates have been reduced by 30% as discussed in my testimony.

2025 Union Contract Changes

Report Pulled: 11/1/2024 **Item ID: 13951**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - One Time **Work Type** Project

Alias HR - 2020 Union Changes, Human Resources - 2020 Union Changes, Human Resources -2020 Union Changes, Human Resources -2025 Union Contract Changes, People & Culture - 2025 Union Contract Changes, 2025 Union Contract Changes

Description The 2025 Union Contract Changes project will implement SAP and other system changes required as a result of three collective bargaining agreements which will be renegotiated and ratified. Collective bargaining agreements expire every five years for Operating Maintenance and Construction ("OM&C"), Virtual Contact Center ("VCC"), and Zeeland employee groups. For OM&C, the current agreement ends June 1, 2025. The VCC agreement ends August 1, 2025. The Zeeland agreement ends October 1, 2025.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement Collective bargaining agreements expire every five years for OM&C (Operating Maintenance and Construction), CCC (Customer Contact Center) and Zeeland employee groups. For OM&C, the current agreement ends June 1, 2025 . CCC agreement ends in August 1, 2025. Zeeland agreement ends October 1, 2025. Technology changes are required to reflect these new agreements. Otherwise, employees in these union groups may not be paid appropriately or get correct benefits.

Objectives Completion of this project will provide value to the Company and its customers through: (1) waste elimination by making changes in the software for any pay and benefit changes as required by the new agreements; (2) defect reduction by adding process automation to otherwise manual processes for tracking and recording work, premium, and absence time; and (3) improved employee engagement among the OM&C, CCC, and Zeeland union employees.

Scope The scope of this project encompasses making any system changes required to support the new working agreement for the OM&C, CCC, and Zeeland employees. Exact details will be finalized after the negotiation process is completed and contracts are approved.

Alternatives Three alternatives were considered for this project: (1) Make no system changes after the contracts are ratified. This option was not chosen because it exposes the Company to possible fines, disengaged employees, union grievances, significant manual processes leading to greater possibility of error, hiring additional staff to perform activities outlined in the agreements, and increased legal costs due to employee grievances. (2) Find other third-party software to support the changes required by the union agreements. This option was not chosen because it would require SAP integration along with additional software licensing and maintenance costs. (3) Make system changes to eliminate manual updating, comply with the working agreement language, support union employee engagement, and reduce grievances. Option (3) was chosen because it leverages current SAP technology, automates what would otherwise require manual processing, and is the least costly option.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
4/1/2025	5/15/2025	6/28/2025	12/17/2025
	In-Service/Go-Live	**Closeout**	
	12/18/2025	5/1/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.337	$0.290	$0.008	$0.008	$0.008	-	-	-	$0.651
Total Cost of Ownership	$0.337	$0.290	$0.008	$0.008	$0.008	-	-	-	**$0.651**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.141	$0.114	-	-	-	-	-	-	**$0.255**
Outside Services	$0.174	$0.149	-	-	-	-	-	-	**$0.323**
Business Expense/Overheads	$0.022	$0.018	-	-	-	-	-	-	**$0.040**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.337	$0.282	-	-	-	-	-	-	**$0.619**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.337	$0.290	$0.008	$0.008	$0.008	-	-	-	**$0.651**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.337	$0.290	$0.008	$0.008	$0.008	-	-	-	**$0.651**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Employee Engagement for the three union groups increases as measured annually in the areas of work/life balance and employee satisfaction.
Avoided Costs	If system changes are not made to automate the changes in the union agreements, additional employees/contractors will need to be hired to manually make the changes. The actual number of employees/contractors is not known at this time since union negotiations have not been finalized.
Intangibles	Union employees are engaged because they are being paid correctly per the union contract.
Avoided Costs	When union employees are paid correctly, the chance of grievances and issues with the NLRB (National Labor Relations Board) decreases. Grievances cost the company time and money, including legal costs.

AccessNOW — **Report Pulled: 11/1/2024** — **Item ID: 6665**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval — **Work Type** Project

Alias Dell 1 Identity Manager (CAAR Replacement), Directory Services Enhancements, Dell Identity Manager

Description The AccessNow project will implement configurable identity, Access Management functionality and best practices, and will enforce compliance.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T — **Bus Unit** SECURITY — **Dept** Unspecified

WORK OBJECTIVES

Problem Statement AccessNOW replaced the CAAR system enterprise wide in 2018Q4 with over 50,000 requests being made since product launch. However, AccessNOW's manual processes and lack of integration are leading to increased risk for human error and time spent on processes that can be automated.

Objectives This project will add value by: (1) reducing waste and failure points through automation; (2) improving and standardizing the business partner experience; (3) centralizing access management; (4) ensuring regulatory compliance; and (5) ensuring system stability and continuous improvement.

Scope The project scope includes implementing additional integrations to Active Directory domains that are not currently connected to the AccessNOW application (arreCorp.com, DMZ.cms, ems.com, rtqa.cmsenergy.com, ciphqa.cmsenergy.com) and integration to the Company's SAP system(s) to allow for automation of SAP role access provisioning. In addition, the project scope includes: (1) design, configuration and testing of technical connections; (2) completion of application support pack upgrades to the next version(s) to maintain system stability and to stay current with vendor releases; and (3) review and implement enhancements to improve and standardize the business partner experience.

Alternatives As part of the review process the alternative considered was using manual processes. This option was not chosen because it was deemed too costly and inefficient.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
3/1/2019	4/5/2019	5/31/2019	7/31/2019
	In-Service/Go-Live	**Closeout**	
	3/1/2021	3/30/2021	

FUNDING SUMMARY

	2018	2019	2020	2021	2022	2023	2024	2025 +	Total
Cap+COR	$1.427	$0.205	$1.239	$0.725	$0.365	-	$0.431	-	$4.392
O&M	$0.433	$0.164	$0.197	$0.534	$0.248	-	$0.027	-	$1.604
Total Cost of Ownership	$1.860	$0.369	$1.437	$1.259	$0.613	-	$0.459	-	**$5.996**

	2018	2019	2020	2021	2022	2023	2024	2025 +	Total
Labor	$0.552	$0.577	$0.282	$0.216	$0.099	-	$0.546	-	**$2.272**
Outside Services	$1.122	$0.115	$1.091	$0.994	$0.295	-	$(0.103)	-	**$3.514**
Business Expense/Overheads	$0.184	$(0.323)	$0.063	$0.048	$0.017	-	$0.008	$(0.000)	**$(0.003)**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.002	-	-	$0.000	-	-	$0.008	-	**$0.010**
Licenses, Permits & Fees	-	-	-	-	$0.202	-	-	-	**$0.202**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$1.860	$0.369	$1.437	$1.259	$0.613	-	$0.459	$(0.000)	**$5.996**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2018	2019	2020	2021	2022	2023	2024	2025 +	Total
O&M	Reduction	-	$(0.104)	$(0.104)	-	-	-	-	-	**$(0.208)**
	Initial	$0.433	$0.164	$0.197	$0.534	$0.248	-	$0.027	-	**$1.604**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.433	$0.060	$0.093	$0.534	$0.248	-	$0.027	-	**$1.396**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$1.427	$0.205	$1.239	$0.725	$0.365	-	$0.431	-	**$4.392**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$1.427	$0.205	$1.239	$0.725	$0.365	-	$0.431	-	**$4.392**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall)	-0.965

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Procedure & Work Methods	Medium	Medium	Manual processes are prone to human error, which could result in audit findings. We are striving to automate manual processes to automate this.

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Avoided Costs	In 2019 & 2020, the Identity and Access Management Operations team will see positive impacts from an automated system. This will allow the team to avoid hiring additional contractors to keep up with the work.
Intangibles	Morale boost. Replacing the Computer Access and Authorization request system, which was deemed one of the worse processes in the queue company, is considered a boost in company morale.

Add Card Transaction Fees

Report Pulled: 11/1/2024 **Item ID: 13409**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Digital Payment Fee Implementation, Digital Payment Fee Implementation (BOO#316), Add Card Transaction Fees

Description This project will implement a customer paid transaction fee for all customer payments issued using a credit or debit card across all Paymentus payment channels reducing operational costs associated with payment processing.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement The Company's customers have embraced card payment methods and at present credit and debit card payments account for 35% of payment transactions with adoption continuing to increase. Consequently, the Company incurs an annual expenditure of over $15 million to cover card payments. As customer adoption of credit and debit card payments increases, annual operating expenses will also continue to increase.

Objectives This project creates value for the Company and customers by: (1) updating all payment channels to enable customers to pay a fee for debit and credit card transactions; (2) reducing operating costs for payment processing; and (3) removing card payment restrictions on small and medium business customers.

Scope The project scope includes: (1) creating new payment messaging on bills to indicate card payment fee changes; (2) updating autopay functionality in all payment channels; (3) updating all payment channels to include a customer paid transaction fee when using card payment methods segmented by residential and business customers; (4) modifying existing integrations to support card transaction fee changes; and (5) educating customers regarding card transaction fee changes.

Alternatives Alternatives Considered include: (1) Implement a new Business Card Payment Portal which would allow the Company to distinguish between card types and charge a fee to non-residential customers who are utilizing high rebate card types. This alternative was not selected because it would require significant investment to create and maintain a separate business payment portal and the complex card rules which would minimize operating savings. (2) Implement a fee across all payment types, except autopay utilizing automated clearing house payments ("ACH"), in all payment channels for all customers. This alternative was not selected because implementing costs for ACH did not provide the optimal value and experience to customers. (3) Implement a fee for card payment transactions in all payment channels for all customers. This alternative was selected because it provides the best balance between achieving the project objectives, controlling costs, and optimizing value to customers.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
3/1/2023	3/10/2023	3/20/2023	9/29/2023
	In-Service/Go-Live	**Closeout**	
	9/30/2023	10/31/2023	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$1.065	-	-	-	-	-	-	-	$1.065
O&M	$0.342	-	-	-	-	-	-	-	$0.342
Total Cost of Ownership	$1.407	-	-	-	-	-	-	-	**$1.407**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.378	-	-	-	-	-	-	-	**$0.378**
Outside Services	$0.893	-	-	-	-	-	-	-	**$0.893**
Business Expense/Overheads	$0.135	-	-	-	-	-	-	-	**$0.135**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.407	-	-	-	-	-	-	-	**$1.407**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	$(3.066)	$(15.000)	$(15.000)	$(15.000)	$(15.000)	$(15.000)	-	-	**$(78.066)**
	Initial	$0.342	-	-	-	-	-	-	-	**$0.342**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$(2.724)	$(15.000)	$(15.000)	$(15.000)	$(15.000)	$(15.000)	-	-	**$(77.724)**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.065	-	-	-	-	-	-	-	**$1.065**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.065	-	-	-	-	-	-	-	**$1.065**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	40.403

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Improved overall customer experience for small and medium businesses ("SMB") due to removing restrictions on card payments. The Company has received direct feedback from SMB customers stating they rely on card payments to successfully manage their businesses and pay bills on time.

Application Currency-Corporate Services-O&M

Report Pulled: 11/1/2024 **Item ID: 10253**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency and Enhancements – Corporate Services - O&M, Application Currency – Corporate Services - O&M, Application Currency-Corporate Services-O&M

Description The Corporate Services initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-PLANNING & GOV

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades in the Corporate Services adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Corporate Services are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.197	$0.493	-	-	-	-	-	-	$0.691
Total Cost of Ownership	$0.197	$0.493	-	-	-	-	-	-	**$0.691**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.024	$0.455	-	-	-	-	-	-	**$0.479**
Outside Services	$0.130	$0.038	-	-	-	-	-	-	**$0.168**
Business Expense/Overheads	$0.003	$0.000	-	-	-	-	-	-	**$0.004**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.041	-	-	-	-	-	-	-	**$0.041**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.197	$0.493	-	-	-	-	-	-	**$0.691**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.197	$0.493	-	-	-	-	-	-	**$0.691**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.197	$0.493	-	-	-	-	-	-	**$0.691**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-Corporate-Capital

Report Pulled: 11/1/2024 **Item ID: 13356**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Corporate-Capital

Description The Corporate Services initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades in the Corporate Services adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Corporate Services are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.125	$0.210	$0.057	$0.197	$0.057	$0.057	$0.057	-	$0.762
O&M	-	-	$0.005	$0.019	$0.005	$0.005	$0.005	-	$0.040
Total Cost of Ownership	$0.125	$0.210	$0.063	$0.216	$0.063	$0.063	$0.063	-	**$0.802**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.125	$0.150	$0.010	$0.034	$0.010	$0.010	$0.010	-	**$0.349**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	-	$0.060	$0.003	$0.012	$0.003	$0.003	$0.003	-	**$0.083**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.050	$0.170	$0.050	$0.050	$0.050	-	**$0.370**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.125	$0.210	$0.063	$0.216	$0.063	$0.063	$0.063	-	**$0.802**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	$0.005	$0.019	$0.005	$0.005	$0.005	-	**$0.040**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	$0.005	$0.019	$0.005	$0.005	$0.005	-	**$0.040**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.125	$0.210	$0.057	$0.197	$0.057	$0.057	$0.057	-	**$0.762**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.125	$0.210	$0.057	$0.197	$0.057	$0.057	$0.057	-	**$0.762**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-Corporate-O&M

Report Pulled: 11/1/2024 **Item ID: 13357**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Corporate-O&M

Description The Corporate Services initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades in the Corporate Services adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Corporate Services are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.258	$0.508	$0.372	$0.333	$0.279	$0.288	$0.279	-	$2.317
Total Cost of Ownership	$0.258	$0.508	$0.372	$0.333	$0.279	$0.288	$0.279	-	**$2.317**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.186	$0.475	$0.348	$0.311	$0.261	$0.269	$0.261	-	**$2.111**
Outside Services	$0.068	-	-	-	-	-	-	-	**$0.068**
Business Expense/Overheads	$0.003	$0.033	$0.024	$0.022	$0.018	$0.019	$0.018	-	**$0.138**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.000	-	-	-	-	-	-	-	**$0.000**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.258	$0.508	$0.372	$0.333	$0.279	$0.288	$0.279	-	**$2.317**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.258	$0.508	$0.372	$0.333	$0.279	$0.288	$0.279	-	**$2.317**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.258	$0.508	$0.372	$0.333	$0.279	$0.288	$0.279	-	**$2.317**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-Customer-O&M

Report Pulled: 11/1/2024 **Item ID: 13359**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Customer-O&M

Description The Customer initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades to the Customer digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within Customer are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.110	$0.174	$0.010	$0.180	$0.008	$0.174	$0.008	-	$0.664
Total Cost of Ownership	$0.110	$0.174	$0.010	$0.180	$0.008	$0.174	$0.008	-	**$0.664**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.093	$0.163	$0.010	$0.168	$0.007	$0.163	$0.007	-	**$0.611**
Outside Services	$0.016	-	-	-	-	-	-	-	**$0.016**
Business Expense/Overheads	$0.000	$0.011	$0.001	$0.012	$0.000	$0.011	$0.000	-	**$0.037**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.001	-	-	-	-	-	-	-	**$0.001**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.110	$0.174	$0.010	$0.180	$0.008	$0.174	$0.008	-	**$0.664**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.110	$0.174	$0.010	$0.180	$0.008	$0.174	$0.008	-	**$0.664**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.110	$0.174	$0.010	$0.180	$0.008	$0.174	$0.008	-	**$0.664**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Customer Management
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-CX&O-Capital

Report Pulled: 11/1/2024 **Item ID: 8890**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency and Enhancements - CE&O - Capital, Application Currency - CE&O - Capital, Application Currency-CE&O-Capital, Application Currency-CX&O-Capital

Description The CX&O initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades in the CX&O adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the CX&O are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.116	$0.091	-	-	-	-	-	-	$0.207
Total Cost of Ownership	$0.116	$0.091	-	-	-	-	-	-	**$0.207**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.030	$0.027	-	-	-	-	-	-	**$0.057**
Outside Services	$0.084	$0.063	-	-	-	-	-	-	**$0.146**
Business Expense/Overheads	$0.003	$0.001	-	-	-	-	-	-	**$0.004**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.116	$0.091	-	-	-	-	-	-	**$0.207**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.116	$0.091	-	-	-	-	-	-	**$0.207**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.116	$0.091	-	-	-	-	-	-	**$0.207**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-CX&O-O&M

Report Pulled: 11/1/2024 **Item ID: 8884**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Applications Currency and Enhancements - CE&O - O&M, Application Currency and Enhancements - CE&O - O&M, Application Currency - CE&O - O&M, Application Currency-CE&O-O&M, Application Currency-CX&O-O&M

Description The CX&O initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades in the CX&O adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the CX&O are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.026	-	-	-	-	-	-	-	$0.026
Total Cost of Ownership	$0.026	-	-	-	-	-	-	-	**$0.026**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.002	-	-	-	-	-	-	-	**$0.002**
Outside Services	$0.024	-	-	-	-	-	-	-	**$0.024**
Business Expense/Overheads	$0.000	-	-	-	-	-	-	-	**$0.000**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.026	-	-	-	-	-	-	-	**$0.026**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.026	-	-	-	-	-	-	-	**$0.026**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.026	-	-	-	-	-	-	-	**$0.026**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Customer Management
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-Electric & Gas Shared-Capital

Report Pulled: 11/1/2024 **Item ID: 13360**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Electric & Gas Shared-Capital

Description The Electric and Gas operations initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Electric and Gas operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Companys ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.071	$0.714	$0.124	$0.394	$0.090	$0.340	-	-	$1.733
O&M	$0.002	$0.342	$0.184	$0.034	$0.453	$0.188	-	-	$1.202
Total Cost of Ownership	$0.073	$1.056	$0.308	$0.428	$0.543	$0.528	-	-	**$2.936**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.034	$0.336	$0.222	$0.241	$0.400	$0.346	-	-	**$1.579**
Outside Services	$0.028	$0.044	-	-	$0.020	-	-	-	**$0.092**
Business Expense/Overheads	$0.012	$0.039	$0.036	$0.117	$0.028	$0.092	-	-	**$0.323**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.050	$0.070	$0.095	$0.090	-	-	**$0.305**
Licenses, Permits & Fees	-	$0.637	-	-	-	-	-	-	**$0.637**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.073	$1.056	$0.308	$0.428	$0.543	$0.528	-	-	**$2.936**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.002	$0.342	$0.184	$0.034	$0.453	$0.188	-	-	**$1.202**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.002	$0.342	$0.184	$0.034	$0.453	$0.188	-	-	**$1.202**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.071	$0.714	$0.124	$0.394	$0.090	$0.340	-	-	**$1.733**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.071	$0.714	$0.124	$0.394	$0.090	$0.340	-	-	**$1.733**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-Electric & Gas Shared-O&M

Report Pulled: 11/1/2024 **Item ID: 13361**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Electric & Gas Shared-O&M

Description The Electric and Gas Operations initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades to the Electric and Gas Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Electric and Gas Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Companys ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.006	$0.122	$0.493	$0.635	$0.466	$0.759	$0.224	-	$2.705
Total Cost of Ownership	$0.006	$0.122	$0.493	$0.635	$0.466	$0.759	$0.224	-	**$2.705**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.002	$0.075	$0.448	$0.594	$0.423	$0.696	$0.199	-	**$2.436**
Outside Services	$0.003	$0.045	$0.014	-	$0.014	$0.014	$0.011	-	**$0.101**
Business Expense/Overheads	$0.000	$0.002	$0.031	$0.042	$0.030	$0.049	$0.014	-	**$0.168**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.006	$0.122	$0.493	$0.635	$0.466	$0.759	$0.224	-	**$2.705**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.006	$0.122	$0.493	$0.635	$0.466	$0.759	$0.224	-	**$2.705**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.006	$0.122	$0.493	$0.635	$0.466	$0.759	$0.224	-	**$2.705**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-EPS-O&M

Report Pulled: 11/1/2024 **Item ID: 6730**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias Enhancements - TSM, Application Currency and Enhancements - Infrastructure Applications and Operations - O&M, Application Currency and Enhancements - IAO - O&M, Application Currency - IAO - O&M, Application Currency-IAO-O&M, Application Currency-EPS-O&M

Description The EPS (formerly IAO) initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Infrastructure > Network Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ENTERPRISE PRODUCTS AND SER

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades in the EPS adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost.

Scope

The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the EPS are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.085	$0.217	-	-	-	-	-	-	$0.302
Total Cost of Ownership	$0.085	$0.217	-	-	-	-	-	-	**$0.302**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.045	$0.141	-	-	-	-	-	-	**$0.186**
Outside Services	$0.034	$0.070	-	-	-	-	-	-	**$0.104**
Business Expense/Overheads	$0.005	$0.006	-	-	-	-	-	-	**$0.011**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.085	$0.217	-	-	-	-	-	-	**$0.302**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.085	$0.217	-	-	-	-	-	-	**$0.302**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.085	$0.217	-	-	-	-	-	-	**$0.302**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-Gas-Capital

Report Pulled: 11/1/2024 **Item ID: 13364**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Gas-Capital

Description The Gas Engineering and Operations initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades.

Portfolio IT Services > Applications > Gas Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-GAS

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades to the Gas Engineering and Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Gas Engineering and Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	$0.037	$0.074	$0.037	$1.462	-	$1.610
O&M	-	-	-	-	$0.021	-	$0.268	-	$0.289
Total Cost of Ownership	-	-	-	$0.037	$0.095	$0.037	$1.730	-	**$1.899**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	-	-	-	$0.025	$0.070	$0.025	$1.250	-	**$1.370**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	-	-	-	$0.012	$0.025	$0.012	$0.480	-	**$0.529**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	-	-	-	$0.037	$0.095	$0.037	$1.730	-	**$1.899**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	$0.021	-	$0.268	-	**$0.289**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	$0.021	-	$0.268	-	**$0.289**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	$0.037	$0.074	$0.037	$1.462	-	**$1.610**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	$0.037	$0.074	$0.037	$1.462	-	**$1.610**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-Gas-O&M

Report Pulled: 11/1/2024 **Item ID: 13365**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Gas-O&M

Description The Gas Engineering and Operations initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Gas Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-GAS

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades to the Gas Engineering and Operations digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Gas Engineering and Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.028	$0.220	$0.105	$0.257	$0.114	$0.219	$0.115	-	$1.059
Total Cost of Ownership	$0.028	$0.220	$0.105	$0.257	$0.114	$0.219	$0.115	-	**$1.059**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.022	$0.218	$0.098	$0.210	$0.106	$0.172	$0.107	-	**$0.935**
Outside Services	$0.004	$0.002	-	-	-	-	-	-	**$0.006**
Business Expense/Overheads	$0.002	$0.001	$0.007	$0.015	$0.008	$0.012	$0.008	-	**$0.052**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.000	-	-	$0.032	-	$0.034	-	-	**$0.066**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.028	$0.220	$0.105	$0.257	$0.114	$0.219	$0.115	-	**$1.059**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.028	$0.220	$0.105	$0.257	$0.114	$0.219	$0.115	-	**$1.059**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.028	$0.220	$0.105	$0.257	$0.114	$0.219	$0.115	-	**$1.059**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-IT/Digital Foundation-Application Plat Report Pulled: 11/1/2024 Item ID: 13366

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-IT/Digital Foundation-Application Platforms-Capital

Description The Application Platforms initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades.

Portfolio IT Services > Infrastructure > End User Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives Maintaining the appropriate versions of applications through application currency upgrades in the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives Applications within the Application Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.063	$0.092	$0.061	$0.238	$0.068	$0.242	$0.071	-	$0.835
O&M	$0.010	$0.141	$0.020	$0.210	$0.052	$0.211	$0.054	-	$0.698
Total Cost of Ownership	$0.073	$0.234	$0.082	$0.447	$0.119	$0.453	$0.125	-	**$1.533**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.073	$0.233	$0.050	$0.323	$0.085	$0.327	$0.089	-	**$1.181**
Outside Services	-	-	-	-	-	-	-	-	**-**
Business Expense/Overheads	-	$0.000	$0.032	$0.124	$0.035	$0.126	$0.036	-	**$0.353**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.073	$0.234	$0.082	$0.447	$0.119	$0.453	$0.125	-	**$1.533**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.010	$0.141	$0.020	$0.210	$0.052	$0.211	$0.054	-	**$0.698**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.010	$0.141	$0.020	$0.210	$0.052	$0.211	$0.054	-	**$0.698**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.063	$0.092	$0.061	$0.238	$0.068	$0.242	$0.071	-	**$0.835**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.063	$0.092	$0.061	$0.238	$0.068	$0.242	$0.071	-	**$0.835**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-IT/Digital Foundation-Application Plat Report Pulled: 11/1/2024 Item ID: 13367

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-IT/Digital Foundation-Application Platforms-O&M

Description The Application Platforms initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Infrastructure > Network Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades to the Application Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Application Platforms area are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.039	$0.052	$0.097	$0.289	$0.231	$0.189	$0.292	-	$1.189
Total Cost of Ownership	$0.039	$0.052	$0.097	$0.289	$0.231	$0.189	$0.292	-	**$1.189**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.037	$0.051	$0.082	$0.270	$0.216	$0.176	$0.272	-	**$1.105**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.003	$0.001	$0.015	$0.019	$0.015	$0.012	$0.019	-	**$0.084**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.039	$0.052	$0.097	$0.289	$0.231	$0.189	$0.292	-	**$1.189**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.039	$0.052	$0.097	$0.289	$0.231	$0.189	$0.292	-	**$1.189**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.039	$0.052	$0.097	$0.289	$0.231	$0.189	$0.292	-	**$1.189**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-IT/Digital Foundation-Infrastructure F Report Pulled: 11/1/2024 Item ID: 13369

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-IT/Digital Foundation-Infrastructure Platforms-O&M

Description The Infrastructure Platforms initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Infrastructure > * > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades in the Infrastructure Platforms adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Infrastructure Platforms are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.007	$0.153	$0.021	$0.039	$0.039	$0.039	$0.039	-	$0.338
Total Cost of Ownership	$0.007	$0.153	$0.021	$0.039	$0.039	$0.039	$0.039	-	**$0.338**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.000	$0.143	$0.018	$0.037	$0.037	$0.037	$0.037	-	**$0.307**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	-	$0.010	$0.003	$0.003	$0.003	$0.003	$0.003	-	**$0.023**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.007	-	-	-	-	-	-	-	**$0.007**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.007	$0.153	$0.021	$0.039	$0.039	$0.039	$0.039	-	**$0.338**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.007	$0.153	$0.021	$0.039	$0.039	$0.039	$0.039	-	**$0.338**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.007	$0.153	$0.021	$0.039	$0.039	$0.039	$0.039	-	**$0.338**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-Operational Technology-Capital

Report Pulled: 11/1/2024 **Item ID: 13370**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Operational Technology-Capital

Description The Operational Technology initiative will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers. The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost.

Scope The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.054	$0.216	-	$0.225	-	$0.466	-	-	$0.961
O&M	$0.069	$0.073	-	$0.055	-	$0.107	-	-	$0.305
Total Cost of Ownership	$0.124	$0.289	-	$0.281	-	$0.573	-	-	**$1.266**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	-	$0.235	-	$0.173	-	$0.350	-	-	**$0.758**
Outside Services	-	$0.000	-	-	-	-	-	-	**$0.000**
Business Expense/Overheads	-	$0.002	-	$0.108	-	$0.223	-	-	**$0.332**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.124	$0.052	-	-	-	-	-	-	**$0.175**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.124	$0.289	-	$0.281	-	$0.573	-	-	**$1.266**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.069	$0.073	-	$0.055	-	$0.107	-	-	**$0.305**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.069	$0.073	-	$0.055	-	$0.107	-	-	**$0.305**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.054	$0.216	-	$0.225	-	$0.466	-	-	**$0.961**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.054	$0.216	-	$0.225	-	$0.466	-	-	**$0.961**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Electric T&D, Gas T&D, Generation
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-Operational Technology-O&M

Report Pulled: 11/1/2024 **Item ID: 11336**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias Operational Technology Software Refresh Program, Application Currency and Enhancements - Operational Technology - O&M, Application Currency and Enhancements - Operational Technology - Capital, Application Currency - Operational Technology - Capital, Application Currency - Operational Technology - O&M, Application Currency-Operational Technology-

Description The Operational Technology initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-TRANS, OPS SUPPORT AND ENG

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.006	-	-	-	-	-	-	-	$0.006
Total Cost of Ownership	$0.006	-	-	-	-	-	-	-	**$0.006**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.005	-	-	-	-	-	-	-	**$0.005**
Outside Services	$0.000	-	-	-	-	-	-	-	**$0.000**
Business Expense/Overheads	$0.000	-	-	-	-	-	-	-	**$0.000**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.006	-	-	-	-	-	-	-	**$0.006**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.006	-	-	-	-	-	-	-	**$0.006**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.006	-	-	-	-	-	-	-	**$0.006**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Electric T&D, Gas T&D, Generation
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-Operational Technology-O&M

Report Pulled: 11/1/2024 **Item ID: 13371**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Application Currency-Operational Technology-O&M

Description The Operational Technology initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades in the Operational Technology adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software and respective database, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Operational Technology are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.034	$0.179	$0.103	$0.326	$0.316	$0.389	$0.316	-	$1.663
Total Cost of Ownership	$0.034	$0.179	$0.103	$0.326	$0.316	$0.389	$0.316	-	**$1.663**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.002	$0.178	$0.087	$0.305	$0.295	$0.364	$0.295	-	**$1.525**
Outside Services	$0.032	$0.000	-	-	-	-	-	-	**$0.032**
Business Expense/Overheads	$0.001	$0.001	$0.016	$0.021	$0.021	$0.025	$0.021	-	**$0.106**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.034	$0.179	$0.103	$0.326	$0.316	$0.389	$0.316	-	**$1.663**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.034	$0.179	$0.103	$0.326	$0.316	$0.389	$0.316	-	**$1.663**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.034	$0.179	$0.103	$0.326	$0.316	$0.389	$0.316	-	**$1.663**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description

Application Currency-Operations-O&M

Report Pulled: 11/1/2024 **Item ID: 8783**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Enhancements - Operations - O&M, Application Currency and Enhancements - Operations - O&M, Application Currency - Operations - O&M, Application Currency-Operations-O&M

Description The Operations initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-OPERATIONS

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades in the Operations adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the Operations are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.001	-	-	-	-	-	-	-	$0.001
Total Cost of Ownership	$0.001	-	-	-	-	-	-	-	**$0.001**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.000	-	-	-	-	-	-	-	**$0.000**
Outside Services	$0.000	-	-	-	-	-	-	-	**$0.000**
Business Expense/Overheads	$0.000	-	-	-	-	-	-	-	**$0.000**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.001	-	-	-	-	-	-	-	**$0.001**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.001	-	-	-	-	-	-	-	**$0.001**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.001	-	-	-	-	-	-	-	**$0.001**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.
Technology Capability	Work Management

Application Currency-Security-Capital

Report Pulled: 11/1/2024 **Item ID: 10483**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Security Application Currency, Application Currency and Enhancements - Security - Capital, Application Currency – Security – Capital, Application Currency-Security-Capital

Description This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrades.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-SECURITY PROGRAM MGI

WORK OBJECTIVES

Problem Statement The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives Maintaining the appropriate versions of applications through application currency upgrades to the Security digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives Applications within Security are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.020	$0.030	$0.146	$0.146	$0.146	$0.146	$0.146	-	$0.781
O&M	$0.001	$0.010	$0.005	$0.011	$0.011	$0.011	$0.011	-	$0.059
Total Cost of Ownership	$0.022	$0.040	$0.151	$0.157	$0.157	$0.157	$0.157	-	**$0.840**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.016	$0.039	$0.104	$0.110	$0.110	$0.110	$0.110	-	**$0.599**
Outside Services	-	-	-	-	-	-	-	-	**-**
Business Expense/Overheads	$0.005	-	$0.047	$0.047	$0.047	$0.047	$0.047	-	**$0.240**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	$0.001	$0.001	-	-	-	-	-	-	**$0.001**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.022	$0.040	$0.151	$0.157	$0.157	$0.157	$0.157	-	**$0.840**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.001	$0.010	$0.005	$0.011	$0.011	$0.011	$0.011	-	**$0.059**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.001	$0.010	$0.005	$0.011	$0.011	$0.011	$0.011	-	**$0.059**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.020	$0.030	$0.146	$0.146	$0.146	$0.146	$0.146	-	**$0.781**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.020	$0.030	$0.146	$0.146	$0.146	$0.146	$0.146	-	**$0.781**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-Security-O&M

Report Pulled: 11/1/2024 **Item ID: 11337**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Security Application Currency, Application Currency and Enhancements - Security - Capital, Application Currency – Security – Capital, Application Currency – Security – O&M, Application Currency-Security-O&M

Description This project will utilize both Capital and O&M funding to keep applications current for security and reliability. O&M is included in this project to complete expense activities associated with Capital upgrade

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-SECURITY PROGRAM MG

WORK OBJECTIVES

Problem Statement The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives Maintaining the appropriate versions of applications through application currency upgrades to the Security digital assets adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives Applications within Security are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.029	$0.016	$0.156	$0.360	$0.360	$0.360	$0.360	-	$1.642
Total Cost of Ownership	$0.029	$0.016	$0.156	$0.360	$0.360	$0.360	$0.360	-	**$1.642**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.029	$0.016	$0.132	$0.337	$0.337	$0.337	$0.337	-	**$1.524**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.000	$0.000	$0.024	$0.024	$0.024	$0.024	$0.024	-	**$0.118**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.029	$0.016	$0.156	$0.360	$0.360	$0.360	$0.360	-	**$1.642**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.029	$0.016	$0.156	$0.360	$0.360	$0.360	$0.360	-	**$1.642**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.029	$0.016	$0.156	$0.360	$0.360	$0.360	$0.360	-	**$1.642**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Application Currency-TEOS-O&M

Report Pulled: 11/1/2024 **Item ID: 8775**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Enhancements - TEOS - O&M, Application Currency and Enhancements - TEOS -O&M, Application Currency - TEOS - O&M, Application Currency-TEOS-O&M

Description The TEOS initiative will utilize O&M funding to keep applications current for security and reliability.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-TRANS, OPS SUPPORT AND ENG

WORK OBJECTIVES

Problem Statement

The Company manages a large number of applications in the technology landscape that require regular version upgrades to maintain vendor-supported software versions. Without vendor supported versions, the Company loses the ability to receive version updates and upgrades to address defects, patch security vulnerabilities, protect against cyberthreats, protect data, and add new features. Failure to upgrade these applications can have a direct negative impact on key customer and business processes, increase support costs, increase unplanned outages, and increase cyber security vulnerabilities.

Objectives

Maintaining the appropriate versions of applications through application currency upgrades in the TEOS adds value by: (1) enabling the Company to maintain vendor support; (2) remediating vendor security vulnerabilities and enhancing security protections; (3) addressing vendor defects that impair stability and functionality, leading to fewer incidents due to outdated software; and (4) addressing version interdependencies and compatibility between systems. This is essential to delivering safe, reliable, and affordable service to the Company's customers.

Scope

The application upgrades in scope are regularly prioritized based on considerations that include application criticality; number of versions behind the current available version; security and operational risk; operational impacts of performing the upgrade; ability to defer; and cost. The scope of upgrading these applications encompasses: (1) upgrading the application software, (2) assessing any new functionality for value to the Company, (3) making necessary configuration changes, (5) testing the upgraded software, and (5) updating documentation related to the integration changes.

Alternatives

Applications within the TEOS are routinely evaluated to determine if and what upgrade efforts are necessary to maintain an appropriate level of currency, as well as the priority of those efforts. During that review, the alternative of delaying the timing of the individual upgrades is considered based on: (1) maintaining an optimal balance between keeping the application current and risking failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) preventing employees from performing their daily tasks. This project makes ongoing upgrades and support for these applications possible and fortifies the Company's ability to keep the large number of applications in the technology landscape secure and operational through upgrades. Without these upgrades, the Company will fall further behind in maintaining vendor-supported software versions, increasing the cost and complexity of the upgrade in the future.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.078	$0.249	-	-	-	-	-	-	$0.327
Total Cost of Ownership	$0.078	$0.249	-	-	-	-	-	-	**$0.327**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.025	$0.224	-	-	-	-	-	-	**$0.249**
Outside Services	$0.051	$0.025	-	-	-	-	-	-	**$0.076**
Business Expense/Overheads	$0.002	$0.000	-	-	-	-	-	-	**$0.002**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.078	$0.249	-	-	-	-	-	-	**$0.327**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.078	$0.249	-	-	-	-	-	-	**$0.327**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.078	$0.249	-	-	-	-	-	-	**$0.327**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Electric T&D, Gas T&D, Generation
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

ARP-Collaboration

EXECUTIVE SUMMARY

Report Pulled: 11/1/2024 **Item ID: 8213**

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP - Collaboration Asset Refresh,ARP — Collaboration, ARP-Collaboration

Description This project will replace the Company's obsolete or out-of date audio, visual, telephony and other communication collaborative tools and equipment.

Portfolio IT Services > Infrastructure > Network Services > Communication Network > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement When Collaboration Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they can be more difficult to keep current with Security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

Objectives This project creates value by: (1) ensuring that the Company's audio, visual, telephony, and other communications systems are stable and reliable; and (2) migrate to new collaboration assets.

Scope The project scope consists of: (1) annually replacing aging collaboration assets; and (2) installing new collaboration assets to account for evolving business requirements.

Alternatives The following alternatives were considered: (1) refresh visual assets and a portion of the audio assets; (2) refresh a portion of the audio assets only; and (3) refresh visual assets only. These alternatives were not chosen due to the risk inherent with a partial replacement of assets, which includes: (1) a reduced supply of equivalent replacement Avaya parts that are no longer being produced; and (2) an erosion of the knowledge technicians possess on discontinued systems.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$1.840	$1.110	$1.186	$1.755	$1.535	$0.895	$1.303	-	$9.623
O&M	$0.146	$0.208	$0.226	$0.222	$0.236	$0.214	$0.228	-	$1.481
Total Cost of Ownership	$1.986	$1.318	$1.412	$1.977	$1.771	$1.109	$1.530	-	**$11.104**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.075	$0.050	$0.259	$0.189	$0.181	$0.168	$0.168	-	**$1.090**
Outside Services	$0.199	$0.285	$0.185	$0.267	$0.226	$0.223	$0.331	-	**$1.716**
Business Expense/Overheads	$0.019	$0.188	$0.027	$0.031	$0.030	$0.029	$0.029	-	**$0.352**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$1.689	$0.796	$0.940	$1.491	$1.335	$0.689	$1.003	-	**$7.943**
Licenses, Permits & Fees	$0.003	-	-	-	-	-	-	-	**$0.003**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$1.986	$1.318	$1.412	$1.977	$1.771	$1.109	$1.530	-	**$11.104**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.146	$0.208	$0.226	$0.222	$0.236	$0.214	$0.228	-	**$1.481**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.146	$0.208	$0.226	$0.222	$0.236	$0.214	$0.228	-	**$1.481**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$1.840	$1.110	$1.186	$1.755	$1.535	$0.895	$1.303	-	**$9.623**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$1.840	$1.110	$1.186	$1.755	$1.535	$0.895	$1.303	-	**$9.623**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	The Company' research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures; 2) avert customer frustration and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.

ARP-Core Network Upgrade

Report Pulled: 11/1/2024 **Item ID: 6686**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias Core Network Refresh, ARP - Core Network Upgrade, ARP-Core Network Upgrade, ARP-Core Network

Description This project will refresh the Data Center network equipment.

Portfolio IT Services > Infrastructure > Network Services > Data Network > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement When network assets that are used to support customer interactions and ensure the stability of mission critical business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

Objectives This project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; and (4) standardizing network infrastructure across Data Centers.

Scope The project scope includes the replacement of all core network devices with next generation devices.

Alternatives The alternative considered was to continue running in the current state or delay the replacement of network devices and accept the risk of further business and customer impact when more equipment failures occur.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live
12/31/2021

Closeout

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.026	-	-	$0.540	$0.541	$2.040	$1.278	-	$4.425
O&M	-	-	-	$0.034	$0.035	$0.118	$0.032	-	$0.219
Total Cost of Ownership	$0.026	-	-	$0.574	$0.576	$2.158	$1.310	-	**$4.644**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.019	-	-	$0.030	$0.030	$0.135	$0.060	-	**$0.274**
Outside Services	-	-	-	$0.022	$0.022	$0.085	$0.070	-	**$0.199**
Business Expense/Overheads	$0.007	-	-	$0.011	$0.012	$0.130	$0.051	-	**$0.212**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	$0.510	$0.511	$1.808	$1.129	-	**$3.959**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.026	-	-	$0.574	$0.576	$2.158	$1.310	-	**$4.644**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	$0.034	$0.035	$0.118	$0.032	-	**$0.219**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	$0.034	$0.035	$0.118	$0.032	-	**$0.219**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.026	-	-	$0.540	$0.541	$2.040	$1.278	-	**$4.425**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.026	-	-	$0.540	$0.541	$2.040	$1.278	-	**$4.425**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	The Company' research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures; 2) avert customer frustrations and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.

ARP-Cyber Security

EXECUTIVE SUMMARY

Report Pulled: 11/1/2024 **Item ID: 8240**

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP-Cyber Security,Asset Refresh Program - Cyber Security, ARP-Cyber Security

Description This project will replace cyber security infrastructure to support increasing system and application demands and to prevent system failures and service interruptions.

Portfolio Corporate Services > Security Services > Cyber Security & Shared Services > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-SECURITY PROGRAM MC

WORK OBJECTIVES

Problem Statement When enterprise software or cyber security infrastructure used to support and enhance customer interactions is obsolete, these assets are more expensive to support and can be more difficult to keep current with security updates.

Objectives This project will create value by maintaining the currency of the cyber security infrastructure for core enterprise software. These are used to ensure the stability of technology for business operations.

Scope The scope of this project consists of: (1) annually replacing a subset of cyber security firewalls and servers in keeping with a 3-5 year hardware lifecycle; and (2) performing application upgrades.

Alternatives As part of the review process, the alternatives considered were to: (1) upgrade or replace only those assets identified in the plan; (2) upgrade or replace a portion of the assets identified in the plan. Option 1 was not chosen based on continued refresh cycle for cyber security assets to avoid security risks, system vulnerabilities, and out-of-warranty repair costs. Option 2 was not chosen due to the security risk inherent with not replacing assets as per standard refresh cycles increased system vulnerabilities, and out-of-warranty repair costs.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	$0.468	$0.451	$0.454	$0.380	$0.380	$0.380	-	$2.512
O&M	-	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	-	$0.150
Total Cost of Ownership	-	$0.493	$0.476	$0.479	$0.405	$0.405	$0.405	-	**$2.662**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	-	$0.047	$0.075	$0.075	$0.075	$0.075	$0.075	-	**$0.422**
Outside Services	-	$0.002	-	-	-	-	-	-	**$0.002**
Business Expense/Overheads	-	$0.004	$0.030	$0.030	$0.030	$0.030	$0.030	-	**$0.154**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	$0.440	$0.371	$0.374	$0.300	$0.300	$0.300	-	**$2.084**
Licenses, Permits & Fees	-	$0.000	-	-	-	-	-	-	**$0.000**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	-	$0.493	$0.476	$0.479	$0.405	$0.405	$0.405	-	**$2.662**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	-	**$0.150**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	$0.025	$0.025	$0.025	$0.025	$0.025	$0.025	-	**$0.150**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	$0.468	$0.451	$0.454	$0.380	$0.380	$0.380	-	**$2.512**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	$0.468	$0.451	$0.454	$0.380	$0.380	$0.380	-	**$2.512**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
System Failure (SAP & Other)	Medium	Medium	The risks associated with not completing the program are impacts on business operations that are in service of the Company's customers. The probability of these risk occurring increases as the age of the asset increases. Unless linked to a specific corporate or IT risk, you would skip this section, and go to Other Impacts if risk mitigation

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Technology Capability	Compliance & Risk Management
Risk Mitigation	The Company' research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: 1) Avoid increasing costs as the result of hardware failures; 2) avert customer frustration and employee downtime; 3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities; 4) continue operating system support as older versions are retired by the manufacturer; and 5) ensure employees have the required software to perform their work.

ARP-Field Device Asset Management (FDAM)

Report Pulled: 11/1/2024 **Item ID: 8241**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP – Field Device Asset Management (FDAM),ARP — Field Device Asset Management (FDAM), ARP-Field Device Asset Management (FDAM)

Description This project will replace field devices according to a four-year refresh cycle that is based on industry standards, hardware failures, security patches, and software compatibility.

Portfolio IT Services > Infrastructure > End User Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement When Field Device Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with Security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular four-year refresh cycle.

Objectives This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing field devices prior to increasing hardware failures; and (2) allowing field workers to complete their job tasks.

Scope The project scope consists of replacing field device assets according to the four-year refresh cycle.

Alternatives The alternatives considered were to: (1) extend the replacement cycle from four years to five years for field devices; and (2) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the assets that need refreshing in future years based on the number of devices that were not replaced during the four year refresh cycle; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle to alleviate these concerns.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$3.274	$3.944	$3.457	$7.678	$5.774	$5.072	$3.457	-	$32.655
O&M	$0.002	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	-	$0.033
Total Cost of Ownership	$3.276	$3.949	$3.462	$7.683	$5.779	$5.077	$3.462	-	**$32.688**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.015	$0.033	$0.055	$0.134	$0.097	$0.083	$0.055	-	**$0.473**
Outside Services	-	$0.048	-	-	-	-	-	-	**$0.048**
Business Expense/Overheads	$0.003	$0.015	$0.026	$0.063	$0.046	$0.039	$0.026	-	**$0.217**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$3.258	$3.854	$3.381	$7.486	$5.636	$4.954	$3.381	-	**$31.950**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$3.276	$3.949	$3.462	$7.683	$5.779	$5.077	$3.462	-	**$32.688**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.002	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	-	**$0.033**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.002	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	-	**$0.033**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$3.274	$3.944	$3.457	$7.678	$5.774	$5.072	$3.457	-	**$32.655**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$3.274	$3.944	$3.457	$7.678	$5.774	$5.072	$3.457	-	**$32.655**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	6 - Asset Management
Intangibles	Field Devices supports/enables asset and operational metric data entry; Work Order Process and Close Out; Resource Management Process (On-Premise vs Traveling/Non-Prem); Supports being able to display Engineering Design Process (Redline/Green Line Drawings), and Storm Restoration in the field by have reliable technology.
Intangibles	Replacing field equipment on a four-year refresh cycle benefits external customers because employees will be able to complete work in a timely manner, which increases customer satisfaction.
Risk Mitigation	The Company' research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures, (2) avert customer frustration and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.

ARP-Infoblox Refresh

Report Pulled: 11/1/2024 **Item ID: 6529**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP - Infoblox Refresh,ARP — Infoblox Refresh, ARP-Infoblox Refresh

Description This project will replace the three legacy core components, Domain Name System ("DNS"), Dynamic Host Configuration Protocol ("DHCP"), and Internet Protocol Address Management ("IPAM") also referred to as DDI ("DNS, DHCP, IPAM") environment with a modern, vendor supported system. Infoblox is the DDI solution that the Company uses to enable seamless network communications across critical systems.

Portfolio IT Services > Infrastructure > End User Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement When Infoblox Assets that are used to support customer interactions and ensure the stability of technology for business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with Security updates. Consumers Energy also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

Objectives The value of this program includes: (1) enabling the Company to efficiently manage and control their networks; and (2) providing Domain Name System ("DNS"), Dynamic Host Configuration Protocol ("DHCP"), and Internet Protocol Address Management ("IPAM").

Scope The scope of this project includes the replacement of DNS, DHCP and IPAM assets on a 5-7 years refresh cycle.

Alternatives The alternative considered was to continue operating on existing Infoblox equipment past the vendor's end-of-support date. This alternative was not selected because it carries risks with not having vendor support, software bug fixes, security updates, and other software fixes. The alternative to replace the existing Infoblox equipment with the latest hardware and software provided by the vendor was selected to avoid these risks and continue a regular refresh cycle.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	-	-	-	$0.978	$0.197	$0.120	-	-	$1.296
O&M	-	-	-	$0.054	$0.032	-	-	-	$0.086
Total Cost of Ownership	-	-	-	$1.032	$0.230	$0.120	-	-	**$1.382**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	-	-	-	$0.065	$0.045	$0.020	-	-	**$0.130**
Outside Services	-	-	-	$0.050	$0.030	$0.010	-	-	**$0.090**
Business Expense/Overheads	-	-	-	$0.022	$0.017	-	-	-	**$0.039**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	$0.895	$0.137	$0.090	-	-	**$1.122**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	-	-	-	$1.032	$0.230	$0.120	-	-	**$1.382**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	$0.054	$0.032	-	-	-	**$0.086**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	$0.054	$0.032	-	-	-	**$0.086**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	$0.978	$0.197	$0.120	-	-	**$1.296**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	$0.978	$0.197	$0.120	-	-	**$1.296**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Every business-critical application is positively impacted by this refresh. Everything that runs on the network relies on this system.
Risk Mitigation	The company' research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures, (2) avert customer frustration and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.

ARP-Local Area Network

Report Pulled: 11/1/2024 **Item ID: 6789**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias LAN Refresh,Local Area Network Refresh, ARP - Local Area Network, ARP-Local Area Network

Description This project will upgrade the Company's entire LAN and a significant portion of the Wireless Local Area Network (WLAN).

Portfolio IT Services > Infrastructure > Network Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement

At some Company locations, LAN equipment has been in service since 2011. If the LAN/WLAN hardware and software is not routinely refreshed, the Company will lose the manufacturer support needed for equipment bug fixes, security vulnerability patches, and enhancements. In addition, aging equipment cannot accommodate the increasing demand for wireless devices necessary to perform day-to-day operations that rely on wireless-enabled devices, such as rugged field devices, cell phones, barcode scanners, tablets, and other mobile devices. As equipment ages, it is at risk of higher failure rates, which increases the risk of unplanned outages. In the event of unplanned outages, business areas would not be able to access services on the corporate network including email, SAP, internet, and phones.

Objectives

The project will create value for the Company and its customers by: (1) increasing network reliability; (2) adding new functionality; (3) improving network performance; (4) ensuring equipment is vendor supported, thereby ensuring support for bug fixes, security vulnerability patching, and enhanced features; (5) providing consistent wireless coverage across Company locations; (6) increasing user productivity through a higher performing wireless network, which increases the productivity and efficiency of office and field employees serving customers; and (7) improving support for wireless Internet Protocol (IP) phones, Internet of Things(IoT) and field devices.

Scope

The project scope includes: (1) refreshing the LAN equipment and software across all Company sites; (2) identifying the required features for the new equipment; (3) implementing the new equipment according to industry best practices; (4) replacing wireless network with upgraded infrastructure and verifying wireless coverage is as expected; and (5) collecting wireless survey data for all Company locations in order to design improved wireless network coverage.

Alternatives

The alternative considered was to continue operating on the existing platform past the vendors end-of-support date. The vendor support period ended in May of 2021, and paying for extended support is not an option offered by the vendor. The risk inherent in not refreshing the platform is a lack of vendor support resulting in an absence of software bug fixes, security updates, and break fixes. The Company chose to replace the existing equipment with the latest hardware and software available, following a five year refresh cycle.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$4.846	$4.190	$0.320	$0.511	$0.474	$0.367	$0.375	-	$11.083
O&M	$0.114	$0.086	$0.058	$0.047	$0.031	$0.028	$0.045	-	$0.409
Total Cost of Ownership	$4.959	$4.275	$0.378	$0.558	$0.505	$0.396	$0.420	-	**$11.491**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.300	$0.441	$0.091	$0.133	$0.100	$0.070	$0.075	-	**$1.210**
Outside Services	$0.240	$0.571	$0.029	$0.033	$0.017	$0.015	$0.025	-	**$0.930**
Business Expense/Overheads	$0.089	$0.154	$0.028	$0.014	$0.011	$0.009	$0.010	-	**$0.314**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$4.047	$3.016	$0.231	$0.379	$0.377	$0.302	$0.310	-	**$8.660**
Licenses, Permits & Fees	$0.283	$0.094	-	-	-	-	-	-	**$0.377**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$4.959	$4.275	$0.378	$0.558	$0.505	$0.396	$0.420	-	**$11.491**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.114	$0.086	$0.058	$0.047	$0.031	$0.028	$0.045	-	**$0.409**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.114	$0.086	$0.058	$0.047	$0.031	$0.028	$0.045	-	**$0.409**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$4.846	$4.190	$0.320	$0.511	$0.474	$0.367	$0.375	-	**$11.083**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$4.846	$4.190	$0.320	$0.511	$0.474	$0.367	$0.375	-	**$11.083**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	The Company' research demonstrates that industry standards on refreshing hardware are generally two to three years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures; 2) avert customer frustrations and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work. Manufacturer support will not be provided after May 2021. In the event of unplanned outages, the business would not be able to access the corporate network including email, SAP, internet, and phones.

ARP-Operational Technology Support Gas

Report Pulled: 11/1/2024 **Item ID: 6530**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP - Critical Infrastructure Support, 2014 CIS Asset Refresh,ARP — Operational Technology Support, ARP — Operational Technology Support Gas, ARP-Operational Technology Support Gas

Description The ARP- OT Support Gas project will replace dated and obsolete servers on a rotating 5 year refresh schedule.

Portfolio IT Services > Infrastructure > Data Center - Enterprise Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement When OT Assets that are used to support customer interactions and ensure the stability of technology for business operations are obsolete or out-of-date, they are more expensive to support and can be more difficult to keep current with Security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

Objectives This project creates value by maintaining the currency of the Company's IT infrastructure and the core enterprise software that are utilized to support the operation of the Company's critical gas infrastructure.

Scope The program scope consists of: (1) replacement of computer hardware under the program; and (2) installing additional new compute capacity to account for expanding business requirements.

Alternatives The alternatives considered include: (1) continue to operate hardware beyond a five year refresh cycle or (2) refresh hardware based on a five year refresh cycle along with evaluating the health of the asset and evolving business needs. The alternative to operate hardware beyond a five year refresh cycle was not selected due to the risk that these hardware component failures would cause system reliability and safety for customers. The Company chose the alternative to refresh this hardware based on a five year refresh cycle along with evaluating the health of the asset and evolving business needs to reduce the risk of impacting critical infrastructure that supports systems such as Gas SCADA and Gas Compression control systems.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.245	$1.033	$0.979	$2.766	$1.937	$1.911	$2.643	-	$11.515
O&M	$0.017	$0.020	$0.120	$0.454	$0.302	$0.267	$0.322	-	$1.501
Total Cost of Ownership	$0.262	$1.053	$1.100	$3.220	$2.239	$2.178	$2.965	-	**$13.016**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.009	$0.040	$0.041	$0.270	$0.199	$0.244	$0.226	-	**$1.029**
Outside Services	$0.006	$0.009	$0.022	-	-	-	-	-	**$0.037**
Business Expense/Overheads	$0.003	$0.006	$0.077	$0.281	$0.201	$0.220	$0.254	-	**$1.041**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.046	$0.931	$0.902	$2.564	$1.769	$1.652	$2.411	-	**$10.274**
Licenses, Permits & Fees	$0.198	$0.068	$0.058	$0.105	$0.070	$0.062	$0.074	-	**$0.634**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.262	$1.053	$1.100	$3.220	$2.239	$2.178	$2.965	-	**$13.016**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.017	$0.020	$0.120	$0.454	$0.302	$0.267	$0.322	-	**$1.501**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.017	$0.020	$0.120	$0.454	$0.302	$0.267	$0.322	-	**$1.501**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.245	$1.033	$0.979	$2.766	$1.937	$1.911	$2.643	-	**$11.515**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.245	$1.033	$0.979	$2.766	$1.937	$1.911	$2.643	-	**$11.515**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	High	The risks associated with not completing the program are both disruptive and adverse performance impacts on business operations that Operational Technology supports, which includes Gas Control and Gas Compressor Stations. The probability of these risks occurring increases as the age of the asset increases. Specifically: (1) There will be no security updates without the replacement, which increases our vulnerability. (2) Monitors to maintain the equipment will not be available. (3) Cyber security vulnerabilities will increase with aged systems, which make the systems more prone to attack and compromise. (4) This ensures compliance with TSA Security Directives and API standard 1164 required by the MPSC.

OTHER VALUE

Type	Description
Technology Capability	Gas T&D, Gas Compression
Risk Mitigation	The Company's research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures, (2) avert customer frustration and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.
Intangibles	This reduces the risk of potential cyber security incidents because upgraded systems have been built and calibrated for newer types of cyber-attacks. If the Operational Technology systems are not upgraded, it will affect the ability for Consumers Energy to meet the regulatory and compliance requirements needed for successful customer-facing operations.

ARP-Physical Security

Report Pulled: 11/1/2024 **Item ID: 8176**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias Physical Security,Physical Security Asset Refresh, ARP-Physical Security

Description The ARP-Physical Security, formerly known as Physical Security Asset Refresh, will enhance or replace physical security assets to provide improved visibility and incident resolution related to security concerns.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-SECURITY PROGRAM MC

WORK OBJECTIVES

Problem Statement The Company has several thousand physical security asset devices currently in use including security cameras, motion detectors, intrusion detection systems, and card access systems. Current limitations include the lack of integrated solutions for centralized management, situational awareness, real time monitoring, compliance with regulations and guidelines, and faster responses to emergencies and incidents. This could result in the increase of potential security vulnerabilities, associated penalties, and reputational damage.

Objectives The value provided by completing the project is to: (1) maintain compliance with State and Federal Regulations; (2) reduce redundancies with less of a need for multiple cameras and reducing gaps in functionality; and (3) optimize overall system performance.

Scope Included in the project is the enhancement or replacement of assets including: (1) advanced door systems at Company buildings; (2) security cameras for monitoring capabilities; and (3) gate and lock systems, which include security cameras, motion detectors, intrusion detection systems, and card access systems.

Alternatives Alternatives considered include: (1) not refreshing physical security assets, and (2) defer a portion of the refresh of physical security assets per an asset refresh cycle industry standard. Alternatives 1 and 2 were not selected due to the risk of security concerns, incident resolution, and the inability to meet FERC requirements. The alternative selected maintains compliance, reduces redundancies and gaps in functionality, and optimizes overall performance of physical security systems.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$1.438	$1.552	$1.903	$2.473	$2.475	$2.475	$2.475	-	$14.790
O&M	$0.014	$0.030	$0.013	$0.013	$0.013	$0.013	$0.013	-	$0.107
Total Cost of Ownership	$1.451	$1.582	$1.915	$2.486	$2.487	$2.487	$2.487	-	**$14.897**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.014	$0.036	$0.128	$0.164	$0.164	$0.164	$0.164	-	**$0.832**
Outside Services	$0.623	$0.887	$0.454	$0.589	$0.589	$0.589	$0.589	-	**$4.320**
Business Expense/Overheads	$0.016	$0.002	$0.335	$0.435	$0.435	$0.435	$0.435	-	**$2.091**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.799	$0.657	$0.999	$1.299	$1.300	$1.300	$1.300	-	**$7.653**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$1.451	$1.582	$1.915	$2.486	$2.487	$2.487	$2.487	-	**$14.897**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.014	$0.030	$0.013	$0.013	$0.013	$0.013	$0.013	-	**$0.107**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.014	$0.030	$0.013	$0.013	$0.013	$0.013	$0.013	-	**$0.107**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.438	$1.552	$1.903	$2.473	$2.475	$2.475	$2.475	-	**$14.790**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.438	$1.552	$1.903	$2.473	$2.475	$2.475	$2.475	-	**$14.790**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Theft/Accidental Disclosure	Low	Medium	Having cameras and other physical security assets can help uncover activities leading to potential thefts and or accidents.

OTHER VALUE

Type	Description
Technology Capability	Compliance & Risk Management
Risk Mitigation	Lack of life cycle replacement wouldn't allow for integrated solutions for centralized management, situational awareness, real time monitoring, compliance with regulations and guidelines, and faster, more effective/consistent response to emergencies and incidents which could result in the increase of potential security vulnerabilities, associated penalties and reputation damage.
Intangibles	Security Visibility - Having updated camera/Door systems helps the security command center have been visibility into often un-monitored areas.

ARP-Printer Asset Management (PAM)

Report Pulled: 11/1/2024 **Item ID: 6671**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias Printer Asset Management,ARP — Printer Asset Management (PAM), ARP-Printer Asset Management (PAM)

Description This project will replace and install select printers, plotters, and multi-function printing devices based on printer replacement assessments and a five-year refresh cycle. Printer service and usage history is evaluated and a determination is made if a printer can be repurposed instead of ordering a new one.

Portfolio IT Services > Infrastructure > End User Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement When Printer Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with firmware and security updates. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

Objectives This project creates value for the Company by: (1) improving the dependability of these printer devices for employees; (2) averting increased costs due to hardware repairs; and (3) ensuring compatibility with enterprise print applications.

Scope The project scope consists of the annual replacement of printer assets according to a five-year refresh cycle.

Alternatives The alternatives considered for the project included looking at refresh cycles from three to seven years as well as running the assets to failure. The selection of a five-year cycle was deemed to be the best solution since anything less than five years would increase the likelihood of unneeded expense for replacement of assets that were still in good operating condition. Anything greater than five years is assessed monthly to ensure it is not run-to-failure, including running the asset to failure, resulting in additional expenses for maintenance of the equipment and downtime, negatively affecting employee productivity. The Company assesses the printer fleet based on years of active service, service history, printer usage data, and the number of users within a facility. Based on these factors, the Company either decommissions, repurposes, leaves in place, or refreshes the printers.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.333	$1.037	$1.612	$0.131	$0.657	$0.352	$1.083	-	$5.205
O&M	$0.019	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	-	$0.049
Total Cost of Ownership	$0.352	$1.042	$1.617	$0.136	$0.662	$0.357	$1.088	-	**$5.254**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.030	$0.035	$0.030	$0.002	$0.011	$0.006	$0.031	-	**$0.144**
Outside Services	$0.001	$0.007	-	-	-	-	-	-	**$0.008**
Business Expense/Overheads	$(0.013)	$0.007	$0.014	$0.001	$0.005	$0.001	$0.015	-	**$0.029**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.334	$0.994	$1.573	$0.134	$0.646	$0.349	$1.042	-	**$5.073**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.352	$1.042	$1.617	$0.136	$0.662	$0.357	$1.088	-	**$5.254**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.019	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	-	**$0.049**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.019	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	-	**$0.049**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.333	$1.037	$1.612	$0.131	$0.657	$0.352	$1.083	-	**$5.205**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.333	$1.037	$1.612	$0.131	$0.657	$0.352	$1.083	-	**$5.205**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	High	If Consumers Energy does not stay current with printer hardware, then it would not be able to use the updated software and would lose print functionality.

OTHER VALUE

Type	Description
Technology Capability	Asset Management
Risk Mitigation	The company' research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures, (2) avert customer frustration and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.
Technology Capability	The PAM program supports Engineering Design Process (Redline/Green Line Drawings); Storm Restoration (Hard Print for Damage Assessment). The daily print operations for Business Partners to complete their work as it relates to storms restorations, projects, D & E renderings and application process work.

ARP-Radio

Report Pulled: 11/1/2024 **Item ID: 8234**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP - Wireless Network,ARP — Wireless Network, ARP — Radio, ARP-Radio

Description This project will refresh hardware to include; 800Mhz Radios and infrastructure, cellular modems, plant radios and systems, cellular amplification devices, vehicle consoles in service trucks, other communications equipment, and associated test equipment. This equipment supports mission critical voice and data communications for plant and field service personnel and dispatch personnel. 800MHz radios are upgraded on a 10-year lifecycle basis. Plant radio systems are upgraded on a scheduled 10-year lifecycle basis. Cellular modems are refreshed on a 5-year life cycle basis. Amplification systems are refreshed on a 10-year life cycle.

Portfolio IT Services > Infrastructure > Network Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement 800MHz, mobile, and portable radios, Plant radios systems, and Cellular modems support core business functions, life safety communications, and rapid response for restoration of customers service and critical infrastructure. Company radio and cellular systems must be refreshed on a scheduled basis or risk exceeding life expectancy and failing or becoming obsolete. The refresh of this equipment in a proactive manner is critical to providing service to customers. If these units are not refreshed, the increased risk of unit failure would result in interruptions to timely and concise communications to field personnel to resolve gas leaks, and downed electric lines, or service turn-on requests, which risks life safety.

Objectives This project creates value for customers and the Company by: (1) upholding public safety; (2) ensuring timely responses and repairs to emergent gas leaks, wire downs, and electric outages; (3) ensuring real-time communications between Company dispatch locations and crews in the field; (4) ensuring the safety of personnel working in higher risk workspaces by replacing equipment with units that contain intrinsically safe batteries; (5) supporting continuous improvement and training by replacing equipment that is capable of capturing audio recordings; and (6) remaining in compliance with MPSC regulatory requirements by maintaining critical radio infrastructure.

Scope The project scope consists of: (1) scheduled replacement of radios, modems, and consoles; and (2) installing additional radios modems and console assets to satisfy growth requirements; and (3) scheduled replacement of out of date cellular and radio boosters.

Alternatives The alternatives considered included: (1) Replace the existing units with new units from other radio and modem manufacturers; (2) purchase new radio subscriber units from existing manufacturers. Option 2 was not selected because the Company now uses a standards-based radio system allowing for multiple radio manufacturer options. Option 1 was selected to allow for a competitive bidding process that will provide the most cost-effective radio that will meet the needs of users.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.735	$1.335	$2.389	$2.508	$2.490	$2.884	$2.772	-	$15.115
O&M	$0.063	$0.155	$0.114	$0.222	$0.202	$0.171	$0.090	-	$1.017
Total Cost of Ownership	$0.798	$1.490	$2.503	$2.730	$2.692	$3.055	$2.863	-	**$16.132**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.076	$(0.233)	$0.114	$0.109	$0.098	$0.121	$0.082	-	**$0.367**
Outside Services	$0.035	$0.109	$0.483	$0.483	$0.483	$0.483	$0.523	-	**$2.599**
Business Expense/Overheads	$(0.034)	$0.009	$0.074	$0.078	$0.074	$0.085	$0.073	-	**$0.359**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.719	$1.605	$1.832	$2.061	$2.037	$2.367	$2.185	-	**$12.807**
Licenses, Permits & Fees	$0.001	-	-	-	-	-	-	-	**$0.001**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.798	$1.490	$2.503	$2.730	$2.692	$3.055	$2.863	-	**$16.132**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.063	$0.155	$0.114	$0.222	$0.202	$0.171	$0.090	-	**$1.017**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.063	$0.155	$0.114	$0.222	$0.202	$0.171	$0.090	-	**$1.017**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.735	$1.335	$2.389	$2.508	$2.490	$2.884	$2.772	-	**$15.115**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.735	$1.335	$2.389	$2.508	$2.490	$2.884	$2.772	-	**$15.115**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Avoided Costs	Cost avoidance of future Modem purchases. Transitioning cellular services from modems to devices avoids future yearly modem refresh costs of approximately $420,000.
Risk Mitigation	The company' research demonstrates that industry standards on refreshing radio hardware is generally seven to ten years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures, (2) mitigate customer frustration and employee downtime, (3) maintain high standards for customer and employee safety (4) maintain technology currency for employees to perform their work.
Intangibles	The radio system funded through the ARP — Radio project supports core business functions such as storm restoration, emergency gas leak repair, and day-to-day customer support. By reinvesting in the system Consumers Energy extends the effectiveness of the system.
Risk Mitigation	The risk inherent in not replacing these items is the extended support cost, which amounts to $225,000 annually. Moreover, additional service hour, parts replacement, material, and setup costs would be incurred for outfitting of vehicles.

ARP-Server and Storage

EXECUTIVE SUMMARY

Report Pulled: 11/1/2024 **Item ID: 8755**

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP - Server and Storage,ARP — Server and Storage, ARP-Server and Storage

Description This project will replace or augment server and storage infrastructure for the Company.

Portfolio IT Services > Infrastructure > Data Center - Storage > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement
When Server and Storage Hardware Assets used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and can be more challenging to keep current with Security updates. The Company also runs the risk of failure of these assets impacting customer interactions and business operations if it does not adhere to a regular five to seven-year refresh cycle.

Objectives
This project creates value for the Company through: (1) improved stability and availability of business-critical applications by proactively replacing server and storage hardware assets prior to the likelihood of increasing hardware failures; and (2) ensuring that adequate resources are available to support application demands after five to seven years of actual use.

Scope
The scope of this program encompasses: (1) replacement of server and storage hardware assets; and (2) installation of additional new computers and storage capacity to account for evolving business requirements.

Alternatives
The alternatives considered were to purchase extended maintenance, move some of these assets to the cloud with the Digital -Hybrid Cloud and Data Center Migration project, or to replace the assets on the current cycle. The option to purchase extended maintenance was not selected because full support would not be offered after seven years, and maintenance costs would increase. The preferred option is to move some of these assets to the cloud in the Digital Hybrid Cloud and Data Center Migration project while refreshing the remainder using the five- to seven-year cycle as it is the most cost-effective option. If the Digital-Hybrid Cloud and Data Center Migration project is not approved as part of this rate case, the Company plans to continue to refresh these critical technologies at the current level based on a five- to seven-year refresh cycle to mitigate the risk of failure.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$2.267	$0.774	$1.740	$2.303	$8.171	$3.978	-	-	$19.233
O&M	$0.273	$0.113	$0.139	$0.483	$0.757	$0.214	-	-	$1.979
Total Cost of Ownership	$2.540	$0.887	$1.879	$2.786	$8.928	$4.192	-	-	**$21.212**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.271	$0.104	$0.480	$0.365	$0.640	$0.470	-	-	**$2.331**
Outside Services	$0.157	$0.071	-	$0.010	$0.100	-	-	-	**$0.338**
Business Expense/Overheads	$(0.042)	$0.022	$0.195	$0.141	$0.230	$0.158	-	-	**$0.704**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$1.284	$0.685	$1.203	$1.920	$7.559	$3.565	-	-	**$16.215**
Licenses, Permits & Fees	$0.871	$0.004	-	$0.350	$0.400	-	-	-	**$1.625**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$2.540	$0.887	$1.879	$2.786	$8.928	$4.192	-	-	**$21.212**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.273	$0.113	$0.139	$0.483	$0.757	$0.214	-	-	**$1.979**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.273	$0.113	$0.139	$0.483	$0.757	$0.214	-	-	**$1.979**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.267	$0.774	$1.740	$2.303	$8.171	$3.978	-	-	**$19.233**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.267	$0.774	$1.740	$2.303	$8.171	$3.978	-	-	**$19.233**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	High	Consumers Energy's vendor, Nutanix only offers full support for seven years after purchase of a solution. After the end of support no more security patches are available and if an issue is encountered the manufacturer will not assist in resolving.

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Avoided Costs	If all the existing hardware environment went beyond seven years, O&M would increase would by $202,000. Each 1/7th of the environment not upgraded would equate to an increase in O&M by $30,000.
Avoided Costs	Maintenance costs would increase by about 15% after seven years over current amounts in the ITPM.
Intangibles	Research firm IDC Economics reports that without proactive replacement server performance drops by 39%, annual support costs increase 148%, application management costs increase 40%, and unplanned downtime hours increase by 62%.
Risk Mitigation	The Company's research demonstrates that industry standards on refreshing hardware are generally five to seven years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures; (2) avert customer frustration and employee downtime; (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities; (4) continue operating system support as older versions are retired by the manufacturer; and (5) ensure employees have the required software to perform their work.

ARP-Workstation Asset Management (WAM)

Report Pulled: 11/1/2024 **Item ID: 8242**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ARP - Workstation Asset Management (WAM),ARP — Workstation Asset Management (WAM), ARP-Workstation Asset Management (WAM)

Description This project will replace and install new desktops, laptops, and tablets on a four-year refresh cycle based on industry standards, hardware failures, security patches, and software compatibility. Monitors will be replaced every eight years based on Company data related to historical failure rates.

Portfolio IT Services > Infrastructure > End User Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement When Workstation Assets that are used to support customer interactions and business operations are obsolete or out-of-date, they are more expensive to support and keep current with security updates as equipment becomes obsolete. The Company also runs the risk of failure of these assets if it does not adhere to a regular refresh cycle.

Objectives This project creates value for the Company by: (1) improving stability and availability of business-critical applications by proactively replacing workstations prior to increasing hardware failures; and (2) allowing business partners to complete their job tasks.

Scope The project scope consists of: (1) replacing workstation assets; and (2) installing new units for new resources.

Alternatives The alternatives considered were to: (1) extend the replacement cycle from four years to five years for all desktops and laptops; (2) extend the replacement cycle only on desktops from four years to five years; and (3) use outdated equipment. The Company did not select these options because: (1) there would be an increased risk of hardware failure and equipment outages that could impact the capacity of business partners to complete job tasks; (2) it could cause applications to run poorly or stop functioning; (3) it would increase the ARP in future years based on the number of devices that were not replaced during the four year refresh cycle ; and (4) it could cause an inability to apply security patches. Based on industry data, waiting longer than the four-year cycle would increase hardware failures, security patch issues, and software compatibility concerns, resulting in additional downtime that could affect customer safety and storm restoration. The Company selected a four-year refresh cycle for desktops, laptops, and tablets; and an eight-year cycle for monitors to alleviate these concerns.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$6.152	$5.917	$8.982	$6.070	$7.020	$8.657	$10.765	-	$53.563
O&M	$0.119	$0.028	$0.090	$0.061	$0.071	$0.087	$0.109	-	$0.565
Total Cost of Ownership	$6.272	$5.945	$9.072	$6.131	$7.091	$8.744	$10.873	-	**$54.128**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.251	$0.261	$0.215	$0.145	$0.139	$0.178	$0.216	-	**$1.405**
Outside Services	$0.060	$0.018	$0.127	$0.085	$0.081	$0.104	$0.127	-	**$0.602**
Business Expense/Overheads	$0.113	$0.011	$0.108	$0.073	$0.070	$0.089	$0.108	-	**$0.572**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$5.848	$5.654	$8.622	$5.828	$6.801	$8.373	$10.422	-	**$51.549**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$6.272	$5.945	$9.072	$6.131	$7.091	$8.744	$10.873	-	**$54.128**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.119	$0.028	$0.090	$0.061	$0.071	$0.087	$0.109	-	**$0.565**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.119	$0.028	$0.090	$0.061	$0.071	$0.087	$0.109	-	**$0.565**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$6.152	$5.917	$8.982	$6.070	$7.020	$8.657	$10.765	-	**$53.563**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$6.152	$5.917	$8.982	$6.070	$7.020	$8.657	$10.765	-	**$53.563**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	High	There is a high risk of hardware failure, the inability to keep current with security updates, and software compatibility issues without the four-year refresh.

OTHER VALUE

Type	Description
Technology Capability	6 - Asset Management
Avoided Costs	Future year costs would increase if equipment is not refreshed in planned year.
Risk Mitigation	The company' research demonstrates that industry standards on refreshing hardware are generally eight years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures, (2) avert customer frustration and employee downtime, (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities, (4) continue operating system support as older versions are retired by the manufacturer, and (5) ensure employees have the required software to perform their work.
Technology Capability	The WAM program enables and supports all administrative, engineering, operational, and corporate process and activities.

Asset Accounting Tax Upgrade

Report Pulled: 11/1/2024 **Item ID: 13966**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Asset Accounting Upgrade, Asset Accounting Upgrade 2026, Asset Accounting Upgrade 2025-2026, Asset Accounting Upgrade 2026, Asset Accounting Upgrade 2025-2027, Asset Accounting Tax Upgrade

Description The project will upgrade our current accounting asset management tax software to the SaaS version as required by the vendor or a replacement solution and implement additional new features, ensuring continued support of a critical financial application, and providing new functionality.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement In 2025, standard vendor support ends for the current on-premise PowerTax software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial reporting and improve visibility.

Objectives This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) moving to a SaaS solution in order stay supported; and (2) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support.

Scope The project scope includes: (1) evaluating current vendor/product solution with market leaders; (2) upgrading the vendor software from the current version to the newer SaaS version or replacing it.

Alternatives Alternatives considered include: (1) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (2) Do nothing and remain on unsupported, on-prem tax solution. This option introduces technical and financial risk which would be costly; (3) Upgrade to the newest SaaS version of current on-prem solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2025	3/31/2025	4/30/2025	9/2/2025
	In-Service/Go-Live	**Closeout**	
	10/15/2025	1/31/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.403	$0.336	$0.278	$0.278	$0.278	-	-	-	$1.573
Total Cost of Ownership	$0.403	$0.336	$0.278	$0.278	$0.278	-	-	-	**$1.573**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.109	$0.027	-	-	-	-	-	-	**$0.136**
Outside Services	$0.217	$0.027	-	-	-	-	-	-	**$0.244**
Business Expense/Overheads	$0.023	$0.004	-	-	-	-	-	-	**$0.027**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.054	$0.278	$0.278	$0.278	$0.278	-	-	-	**$1.166**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.403	$0.336	$0.278	$0.278	$0.278	-	-	-	**$1.573**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.403	$0.336	$0.278	$0.278	$0.278	-	-	-	**$1.573**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.403	$0.336	$0.278	$0.278	$0.278	-	-	-	**$1.573**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	9 - A&G Support
Risk Mitigation	Performing this upgrade ensures continued vendor support of a critical application.
Intangibles	The Company improves its financial visibility and ability to react to changing information as a result of running the allocation process on a more frequent basis.
Risk Mitigation	Upgrading the software ensures continued compliance with regulated and financial accounting within the fixed asset sub-ledger.

Asset Accounting Upgrade

Report Pulled: 11/1/2024 **Item ID: 10473**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Asset Accounting Upgrade

Description The project will upgrade our current accounting asset management software to the latest version as required by the vendor and implement additional new features, ensuring continued support of a critical financial application and providing new functionality.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-PLANNING & GOV

WORK OBJECTIVES

Problem Statement

In 2022, standard vendor support ends for the current on-premise software. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. In addition, the upgrade provides additional functionality to increase the frequency of financial reporting and improve visibility. The current monthly allocation process has limited visibility to Company financial performance, and the upgrade provides functionality that allows more frequent allocation processes. Additionally, implementing the vendor's regulatory module eliminates the time-consuming and labor-intensive process of manual data extracts for regulatory analysis used for Cost of Service modeling.

Objectives

This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) eliminating the labor intensive and time-consuming process of pulling data for regulatory analysis used for Cost of Service; (3) automating manual tasks; and (4) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support.

Scope

The project scope includes: (1) upgrading the vendor software from the current version to the newer version; (2) implementing new functionality that includes features for the regulatory Cost of Service analysis, additional reporting, job scheduling, and centralized error processing; and (3) populating the data lake with data from the asset accounting system for improved reporting.

Alternatives

Alternatives considered include: (1) Upgrade to the newest, cloud version of PowerPlan. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing. (2) Evaluate SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would likely be more complex, cost more, and may not provide all the required features. (3) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
7/19/2021	2/17/2022	6/23/2022	10/12/2022
	In-Service/Go-Live	**Closeout**	
	10/13/2022	2/28/2023	

FUNDING SUMMARY

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Cap+COR	$0.926	$2.892	$0.812	-	-	-	-	-	$4.631
O&M	$0.032	$0.086	$0.115	$0.027	$0.050	$0.050	$0.050	-	$0.410
Total Cost of Ownership	$0.959	$2.978	$0.927	$0.027	$0.050	$0.050	$0.050	-	**$5.041**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.031	$0.338	$0.213	-	-	-	-	-	**$0.582**
Outside Services	$0.924	$1.485	$0.569	$0.027	-	-	-	-	**$3.005**
Business Expense/Overheads	$0.004	$0.229	$0.145	-	-	-	-	-	**$0.378**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.925	-	-	-	-	-	-	**$0.925**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.959	$2.978	$0.927	$0.027	-	-	-	-	**$4.891**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2021	2022	2023	2024	2025	2026	2027	2028 +	Total
O&M	Reduction	-	-	$(0.010)	$(0.010)	$(0.010)	$(0.010)	$(0.010)	-	**$(0.050)**
	Initial	$0.032	$0.086	$0.115	$0.027	$0.050	$0.050	$0.050	-	**$0.410**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.032	$0.086	$0.105	$0.017	$0.040	$0.040	$0.040	-	**$0.360**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.926	$2.892	$0.812	-	-	-	-	-	**$4.631**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.926	$2.892	$0.812	-	-	-	-	-	**$4.631**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.993

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	9 - A&G Support
Risk Mitigation	Performing this upgrade ensures continued vendor support of a critical application.
Intangibles	The Company improves its financial visibility and ability to react to changing information as a result of running the allocation process on a more frequent basis.
Intangibles	The Property Accounting area will eliminate waste and increase productivity by eliminating the labor intensive and time-consuming process of pulling data for regulatory analysis used to determine Cost of Service.
Risk Mitigation	Upgrading the software ensures continued compliance with regulated and financial accounting within the fixed asset sub-ledger.

Asset Accounting Upgrade 2025-2026

Report Pulled: 11/1/2024 **Item ID: 13298**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Asset Accounting Upgrade, Asset Accounting Upgrade 2026, Asset Accounting Upgrade 2025-2026, Asset Accounting Upgrade 2026, Asset Accounting Upgrade 2025-2027, Asset Accounting Upgrade 2025-2026

Description The project will upgrade our current accounting asset management software to the latest version as required by the vendor, ensuring continued support of a critical financial application.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement

Standard vendor support will be ending for the current on-premise software on an undisclosed timeline. Losing vendor support creates security and stability risk that can result in performance issues. When the application is out of the normal support with the vendor, the Company no longer receives security patches, support for defect resolution or bug fixes, and cannot enhance the application. To ensure compliance with regulated and financial accounting in the fixed asset sub-ledger, it is necessary to perform an upgrade and maintain vendor support. There are also larger costs to upgrade if the upgrades are further apart due to complex testing activities and too many version increases at any one time.

Objectives

This project creates value for the Company by ensuring compliance with regulated and financial accounting within the fixed asset sub-ledger. In addition, the project adds value by: (1) performing the allocation process on a more frequent basis providing better financial visibility; (2) automating manual tasks; (3) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support; and (4) lowering costs with more frequent upgrades to reduce testing complexities and reduce the number of versions to be adopted.

Scope

The project scope includes: (1) evaluating current vendor/product solution with market leaders; (2) upgrading the vendor software from the current version to the newer version.

Alternatives

Alternatives considered include: (1) Evaluate SAP options for leasing, asset, and tax management capabilities. While this option would eliminate the need for an interface between SAP and PowerPlan, it would be more complex, cost more, and not provide all the required features. (2) Evaluate other software options. This option will introduce new ongoing support costs and integrations and may not provide regulatory reporting and other needed improvements. (3) Analyze and go to cloud possibilities (4) wait until a future upgrade cycle; (5) Upgrade to the newest version of current solution. This is the preferred option as it will reduce hardware and server support costs, provide more frequent software upgrades, avoid database and server upgrades, provide weekly allocation functionality, and provide new features in job scheduling, regulatory reporting for Cost of Service, reporting, and centralized error processing.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2025	3/31/2025	4/30/2025	9/2/2025
	In-Service/Go-Live	**Closeout**	
	10/15/2025	1/31/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.610	$0.073	-	-	-	-	-	-	$0.683
Total Cost of Ownership	$0.610	$0.073	-	-	-	-	-	-	**$0.683**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.163	$0.014	-	-	-	-	-	-	**$0.176**
Outside Services	$0.407	$0.054	-	-	-	-	-	-	**$0.461**
Business Expense/Overheads	$0.040	$0.005	-	-	-	-	-	-	**$0.045**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.610	$0.073	-	-	-	-	-	-	**$0.683**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.610	$0.073	-	-	-	-	-	-	**$0.683**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.610	$0.073	-	-	-	-	-	-	**$0.683**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	9 - A&G Support
Risk Mitigation	Performing this upgrade ensures continued vendor support of a critical application.
Intangibles	The Company improves its financial visibility and ability to react to changing information as a result of running the allocation process on a more frequent basis.
Risk Mitigation	Upgrading the software ensures continued compliance with regulated and financial accounting within the fixed asset sub-ledger.

AxWay Secure Transport 2024 Upgrade

Report Pulled: 11/1/2024 **Item ID: 11748**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , AxWay Secure Transport Upgrade, AxWay Secure Transport 2024 Upgrade, AxWay Secure Transport 2025 Upgrade, AxWay Secure Transport 2024 Upgrade

Description Axway SecureTransport is the Company's multi-protocol Managed File Transfer ("MFT") gateway for securing, managing, and tracking data file flow for our business partners and external vendors. Files impacting billing, HR, Supply Chain, Finance, Alternate Energy Programs, Front Office, Back Office, Device Management, Outage Management and Business Reporting functions utilize these services. This project will update the platform to the current software version, enabling cost saving operational enhancements while retaining data security and platform supportability.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement As Axway Secure Transport is the public-facing managed file transfer gateway, maintaining platform version integrity is critical to ensuring it remains secure and supportable in the event of a cyber attack, outage or other critical incident. A prolonged outage or incident, for any reason, compromises the ability of the Company to perform mission-critical business transactions in finance, operations and direct customer support. Upgrading this application also gives the Company the opportunity to properly scale SecureTransport and take advantage of the growing demand for additional, cost-savings features of the tool, such as managing internal Electronic Data Interchange transactions.

Objectives The value this project brings Consumers Energy and customers includes: (1) Addressing known problems and limitations of the current software and hardware platforms. (2) Ensuring continued secure, scalable, and critical data transmission services running through Axway continue functioning. (3) Creating the capacity to methodically merge/streamline internal and external data file transfer services to eliminate waste. (4) Merging/streamlining the company data file transfer services reducing cyber-attack vectors and creates a more easily maintained and monitored security model.

Scope The scope of this project includes (1) Upgrading the application and database to the current released and supported versions. (2) Refreshing the underlying application infrastructure by upgrading to the latest operating system and hardware platforms. (3) Enable and test expanded Electronic Data Interchange (EDI) functionality.

Alternatives Alternatives considered include: (1) deferring the upgrade. This alternative was not selected because the Axway SecureTransport platform handles critical Company financial, HR and operational transactions--the risk associated with problems stemming from an outdated and unsupported version is too high. Nor would the waste elimination benefits of using the upgraded Axway platform to start consolidating EDI for CE be realized. (2) Replacing the platform. The estimated project costs and timetable for replacing the business functions currently performed by the existing Axway SecureTransport platform would be extensive, and operationally, it is not well suited for a cloud or hybrid cloud solution. In addition to significant platform, application, implementation and functional testing costs, replacing it would require extensive coordination and testing with all of the internal and external account holders, taking upwards of one calendar year. (3) Upgrading the platform. This provides the Company the most cost-effective alternative, balancing costs, known risks, and even growing business capacity and productivity.

DATES (phase end)

Initiation 1/1/2024	**Project Plan & Scope Definition** 1/15/2024	**Final Engineering, Planning & Design** 2/1/2024	**Execution** 2/15/2024
	In-Service/Go-Live 9/14/2024	**Closeout** 9/20/2024	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.477	-	-	-	-	-	-	-	$0.477
Total Cost of Ownership	$0.477	-	-	-	-	-	-	-	**$0.477**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.038	-	-	-	-	-	-	-	**$0.038**
Outside Services	$0.434	-	-	-	-	-	-	-	**$0.434**
Business Expense/Overheads	$0.005	-	-	-	-	-	-	-	**$0.005**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.000	-	-	-	-	-	-	-	**$0.000**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.477	-	-	-	-	-	-	-	**$0.477**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.477	-	-	-	-	-	-	-	**$0.477**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.477	-	-	-	-	-	-	-	**$0.477**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	Medium	An out-of-support version of Secure Transport that Axway no longer provides hotfixes for will put the company network at risk as this is a external (internet) facing application.

OTHER VALUE

Type	Description
Technology Capability	Customer Management
Intangibles	Newer versions of Secure Transport will assist in improving performance of the platform through bug fixes and performance tuning.
Risk Mitigation	The upgrade work will allow CE to harden the application and eliminate a significant single point of failure.

Business Continuity - Program Management Tool

Report Pulled: 11/1/2024 **Item ID: 12679**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Business Continuity - Disaster Recovery Planning Tool, Business Continuity - Program Management Tool

Description The Business Continuity Program Management Tool is critical for successful and effective Business Continuity, Disaster Recovery, and Emergency Management Programs. The software tool will provide automation, enhance the company's incident management processes, establish critical linkages between departments and essential functions they support, and it will perform necessary analysis before, during, and after a disruption that allows for the efficient response to minimize downtime.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CORPORATE SECURITY

WORK OBJECTIVES

Problem Statement The current business continuity and disaster recovery program management tool does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. The current tool limits automation opportunities and has gaps in how it handles template enhancements, which results in the need for manual workarounds in order to prevent losing critical data. The lack of capability affects reporting, upstream / downstream impact mapping, Incident Command System (ICS) documentation automation, and user administration.

Objectives This project will create value for the Company by: (1) maintaining the documentation that supports the recovery efforts of critical processes and associated essential functions that, if disrupted, would present significant impact to the Company and our customers; (2) limiting business and community impact while providing a critical energy service; (3) prioritization of the recovery of critical processes and resource allocation during a business continuity incident(s); (4) providing a consistent, organized and expedient response process (Incident Command System) that is flexible to meet the needs of any incident, regardless of severity or scope; (5) providing a mechanism for identifying restorations gaps between critical business processes and IT recovery capabilities; (6) reducing or eliminating human error and waste; and (7) improved and more efficient user experience.

Scope The project scope includes: (1) framework for the development and maintenance of Business Continuity, System (Application) Recovery Plans, Incident Command System, and Disaster Recovery Plans that are effective and easily accessible during an event; (2) automation for reporting to track status and to measure effectiveness and maturity of the program (Business Continuity, Emergency Management, Disaster Recovery Programs); (3) component for facilitating effective training exercises and response efforts through incident management tools that utilize concepts from the Federal Emergency Management Agency (FEMA) National Incident Management System (NIMS); (4) program management tools to monitor required program deliverables; (5) template for developing and maintaining site hazard assessments; (6) dependency mapping of critical business processes and IT applications; and (7) integrated business impact analysis process.

Alternatives Alternatives considered include: (1) continue to use Riskonnect (current Disaster Recovery tool). This alternative was not selected because it currently does not offer the capabilities to advance program maturity and to foster a world class response to a business interruption. (2) Revert back to manual process. This alternative was not selected because the manual process is time consuming, leads to human struggle and duplicative work. A previous KPMG Audit of the Business Continuity Program indicated the need for interdependency mapping and a software tool is the best way to accomplish this. (3) Implement a best-in-class Cloud Software as a Service (SaaS) solution. This alternative was selected because there are better SaaS solutions that fit the needs outlined above. The final application will be determined after a Request For Proposal is issued and a vendor is selected in the project plan phase.

DATES (phase end)

Initiation 5/2/2026
Project Plan & Scope Definition 7/2/2026
In-Service/Go-Live 2/2/2027
Final Engineering, Planning & Design 8/6/2026
Closeout 3/2/2027
Execution 1/5/2027

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	-	$0.109	$0.144	$0.095	-	-	-	-	$0.348
Total Cost of Ownership	-	$0.109	$0.144	$0.095	-	-	-	-	**$0.348**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	-	$0.075	$0.019	-	-	-	-	-	**$0.094**
Outside Services	-	$0.027	$0.027	-	-	-	-	-	**$0.054**
Business Expense/Overheads	-	$0.007	$0.003	-	-	-	-	-	**$0.010**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	$0.073	$0.073	-	-	-	-	**$0.145**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$0.109	$0.122	$0.073	-	-	-	-	**$0.304**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.109	$0.144	$0.095	-	-	-	-	**$0.348**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.109	$0.144	$0.095	-	-	-	-	**$0.348**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	A new tool leveraging automation would enable Emergency Management Department to save 376 labor hours annually. Calculation: once per quarter, 12 hours is spent going through data for 99 departments to ensure program deliverables are on track. On average 6 hours a week is composing follow-up emails and updating the tracking spreadsheet. About 2-4 hours
Intangibles	Cloud allows for maintenance, upgrades, and patching with no employee/contractor down time.
Technology Capability	Compliance & Risk Management
Risk Mitigation	Having an incident management component enables direct connection to emergency response plans and business continuity plans to facilitate a more efficient response. Incident Command System forms and tools that are integrated will save time and provide clear and concise reporting and recordkeeping. Current planning documentation for incidents is challenging to use, format, produce actionable plans, and get approvals. Current recordkeeping is very manual. This tool will provide a one-stop repository for planning, delivering the plans, recording the progress through multiple operational periods of an incident, and housing records. It will enable improved after-action reporting, tracking, and follow-up such as after-action task assignment, completion date tracking and assignment, late task completion escalation, advanced management-level reporting, and integration to other work management systems such as ServiceNow and SAP to enable pre-populating forms for incidents that begin in other work management applications.
Risk Mitigation	Having cloud with break glass accounts enables the company to access Emergency Response Plans (ERPs), Incident Command System (ICS) forms, and Business Continuity/Disaster Recovery Plans from any device in an event. Break glass accounts are native to the solution that is not managed within CE authentication so if CE gets hit with a ransomware attack or some other event that disables the network, these accounts can be used to still access the tool to get to the plans to assist with recovery.
Intangibles	If no tool is selected to replace the existing SaaS solution and the Company resorted to manual paper processes, Consumers Energy (CE) would have a higher risk of not being able to access mission-critical documentation during events. For Business Continuity, CE would not be able to mature the program and existing programs and preparedness/recovery gaps would remain.

Click to Chat

Report Pulled: 11/1/2024 **Item ID: 12372**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Click to Chat

Description This project will implement a click to chat platform, whereby customers can engage in a chat conversation with customer service agents. This solution will engage agents and customers to measure customer engagement interest and agent performance in handling chat(s) via the Consumers Energy website.

Portfolio Customer Services > Customer Interaction Channels > Digital > Digital > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement The company currently does not offer live chat on our website. Today, more than 41% of customers expect live chat and more than 50% who use mobile phones expect it. That number is only rising each year. J.D. Power found that live chat has become the leading digital contact method for online customers; 42% of customers prefer live chat compared to just 23% for email. Currently, the only way customers can connect with the company are through postal mailing, phone, email, fax, or digital forms. These options are just not efficient enough any longer.

Objectives This project creates value for the Company and it's customers by: (1) determining customer take rate and interest in leveraging chat as an engagement channel for Business Units of VCC and BCC originating from the owner website; (2) determine owner's customer service staff capacity to handle more than one chat session (customer interaction over chat) at a time. Capacity may be up to 4 sessions at a time; and (3) survey customer experience.

Scope The project scope encompasses: (1) chat offer managed based on statistics and state on agent availability and wait time; (2) robust reporting; (3) customer data push based on interactions; (4) agent experience - all interactions (chat, voice, SMS) can be received via software and allow for escalation; (5) monitoring of agent availability across all channels (ex. voice, chat); and (6) full integration across software and backend systems.

Alternatives Alternatives considered include: (1) continue use of the current communication methods. This alternative was not considered because customers prefer to chat with someone in real-time and online, rather than current communication channels (Telephone and Email). (2) Develop a message repository. This alternative was not considered because it is not cost effective and does not address the problem of having the customers' requirements for instant/real-time communication. This alternative could take upwards of 12-24 hours for a response. The recommended alternative of a Click to Chat platform, described in this entry, will involve utilizing industry best-practice vendors for a purpose-built solution to meet the requirements of our customers.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
7/15/2021	8/2/2021	8/15/2021	9/1/2021
	In-Service/Go-Live	**Closeout**	
	3/24/2022	3/31/2022	

FUNDING SUMMARY

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Cap+COR	$0.305	$0.408	$0.189	$0.010	-	-	-	-	$0.912
O&M	$0.006	$0.003	$0.001	$0.000	-	-	-	-	$0.011
Total Cost of Ownership	$0.311	$0.412	$0.190	$0.010	-	-	-	-	**$0.922**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.032	$0.055	$0.013	$0.001	-	-	-	-	**$0.101**
Outside Services	$0.257	$0.261	$0.085	$(0.253)	-	-	-	-	**$0.349**
Business Expense/Overheads	$0.021	$0.095	$0.093	$0.006	-	-	-	-	**$0.215**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	$0.257	-	-	-	-	**$0.257**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.311	$0.412	$0.190	$0.010	-	-	-	-	**$0.922**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2021	2022	2023	2024	2025	2026	2027	2028 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.006	$0.003	$0.001	$0.000	-	-	-	-	**$0.011**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.006	$0.003	$0.001	$0.000	-	-	-	-	**$0.011**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.305	$0.408	$0.189	$0.010	-	-	-	-	**$0.912**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.305	$0.408	$0.189	$0.010	-	-	-	-	**$0.912**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Increase productivity and enhance CXi with Live Chat. Live agents are able to handle more than one interaction at a time which makes them more efficient.

Compression Air Permit And Compliance Digitalization

Report Pulled: 11/1/2024 **Item ID: 12841**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias ER Mobility, Generation Operations Work Management Mobility, Generation Operations Digital Work Management, Generation Operations And Compression Digital Work Management, Generation Compression Digital Work Management, Compression Digital Work Management, Generation Compression Digital Work Management, Gas Compression

Description This project modernizes and expands the use of software and digitized forms in support of station air permits and code compliance at Gas Compression facilities.

Portfolio Gas Delivery Systems > Gas Operations > IT Projects > IT Projects > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-GAS

WORK OBJECTIVES

Problem Statement The current process around air permits and compliance for Gas Compression is cumbersome, largely paper based, and is made up of multiple disconnected systems. This leads to poor visibility, process inefficiency and waste, re-work, regulatory risk, and human error.

Objectives his project provides value to the Company through: (1) increased productivity by direct data entry in the field; (2) improved quality through increased accuracy of updates completed at the time and place of the work; (3) elimination of the need to enter data into multiple disconnected systems, and (4) improved safety through access to real-time information used at work sites rather than printed procedures and forms.

Scope The scope of the project includes: (1) Merging the existing air permit and compliance tools into a single solution, (2) purchasing licenses to add Gas Compression users to the company's existing mobile work management software, and (3) configuring changes in SAP and the mobile work management software to replace the paper-dependent process with the ability to access and update maintenance, operations, and safety information for Gas Compression.

Alternatives Alternatives considered include: (1) Utilize an SAP work management mobile solution. An SAP work management solution was not selected since it is an unproven solution at the Company and would require additional project and support costs. (2) Continue with the manual paper-based processes and forms. Continuing with the manual paper-based processes and forms was not selected because it would not eliminate the identified process waste, re-work, and human error. (3) Customize the existing electronic Shift Operations Management System (eSOMS) mobile application to add work management functions. A customized mobile application was not chosen because it would require additional project cost and an ongoing support budget for a custom solution that the product was not intended to support. (4) Adopt a cloud based SAAS solution. This option was not selected as it was a high-cost option. (5) Utilize the existing Service Suite solution currently deployed for Gas and Electric Distribution. The Service Suite solution was selected because it is both an industry standard and a proven solution at the Company and provides the required mobility and digital benefits at a lower cost than other options.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/6/2026	4/30/2026	6/30/2026	2/24/2027
	In-Service/Go-Live	**Closeout**	
	2/24/2027	3/31/2027	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	$0.462	$0.282	-	-	-	-	-	$0.744
O&M	-	$0.046	$0.064	$0.010	$0.010	$0.010	$0.010	-	$0.150
Total Cost of Ownership	-	$0.508	$0.346	$0.010	$0.010	$0.010	$0.010	-	**$0.894**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	-	$0.343	$0.242	-	-	-	-	-	**$0.585**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	-	$0.164	$0.102	-	-	-	-	-	**$0.266**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.002	$0.002	-	-	-	-	-	**$0.003**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$0.508	$0.346	-	-	-	-	-	**$0.854**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.046	$0.064	$0.010	$0.010	$0.010	$0.010	-	**$0.150**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.046	$0.064	$0.010	$0.010	$0.010	$0.010	-	**$0.150**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.462	$0.282	-	-	-	-	-	**$0.744**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.462	$0.282	-	-	-	-	-	**$0.744**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Employee Engagement improves as the more tech savvy candidate pool for these positions are looking for mobile tools to help them do their jobs.
Intangibles	Productivity increases by using electronic work packages and reducing the need to return to desktop kiosks for updates. With the electronic work packages, (1) employees have remote access to manuals such as the Gas Operations Manual for Gas Compression and local maintenance procedures to reference standard work, (2) it eliminates multiple physical hand-offs of work documents related to the work management process and (3) it frees up planners' time to focus on long-range and outage planning to adhere to goals such as the Periodic Factor metric and Gas Flow Deliverability goal for Gas Compression. Productivity can also be tracked and measured for further improvements. This level of tracking is not possible with the current process and information.
Intangibles	Quality is improved and rework decreases when updates are performed right at the time and place of the work instead of afterwards. For Gas Compression, it (1) eliminates the manual process to update work scope and ensures access to the most up-to-date work order package, (2) allows crews to input SAP Notifications while at the jobsite for improved accuracy of data collected (3) provides the ability to collect asset condition data accurately at the jobsite to feed the data lake for asset health, and allows for the development of electronic code forms with built-in validation to improve quality of compliance data being collected.
Intangibles	Safety is increased as the most current information is at the work site in the mobile device versus a printed procedure.
Avoided Costs	The labor savings on time charging on a toughpad versus re-entering time later in office is 10 mins/day/employee savings from the 15 mins/employee per day it currently takes to enter time. Employees currently take 15mins per day to enter time. 59 Gas Compression employees would save 10mins/day = .17Hour x 230 work days a year x 59 employees = 2,306.9 hours avoided per year * $61 Standard Labor Rate = $140,720.90 Avoided O&M Costs
Risk Mitigation	The project will mitigate the risk of work errors from using outdated procedures especially for performing Gas Compression code work inspections using electronic forms. Electronic forms will improve validation of required inspection data, thereby reducing the risk of MPSC audit findings and possible regulatory fines. It also reduces safety risk by having the ability to have jobsite access to Emergency Plans to meet corporate safety requirements.
Avoided Costs	With this project there are avoided costs in Gas Compression from eliminating paper work package assembly. The time for 6 exempt planners is 2 days per month; 8 planners x 2 days x 8 hours = 128 hours per month. The avoided cost for exempt planners is calculated at 128 hours/month x $48/hour x 12 months = $73,728 per year. Their capital/O&M split is 25/75 which breaks down to avoiding $18,432 in capital and $55,296 in O&M. Six non-exempt admins spend 8 hours/month; 6 admins x 8 hours = 48 hours per month. The avoided cost for non-exempt admins is calculated at 48 hours/month x $25/hour x 12 months = $14,400 per year. Their capital/O&M split is 15/85 which breaks down to avoiding $2,160 in capital and $12,240 in O&M.
Technology Capability	Work Management

Corrosion Control Modernization

Report Pulled: 11/1/2024 **Item ID: 12474**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Corrosion Control Modernization

Description This project will modernize the Corrosion Control measurement, documentation, and analysis process for Gas Transmission and Gas Distribution Corrosion Control. It will also automate the Corrosion Control process and eliminate manual data entry and paper from the process.

Portfolio Gas Delivery Systems > Gas Operations > IT Projects > IT Projects > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-GAS

WORK OBJECTIVES

Problem Statement The current gas pipeline corrosion control field data collection and monitoring process is antiquated and manually intensive. The existing process requires that technicians take readings from the corrosion control devices using a handheld DVM (Digital Voltmeter) and then record those readings on paper, followed by manual data entry into Inspection Manager. The results can then be further stored, processed and analyzed. This process is labor intensive and error prone, which could result in compliance issues, causes rework, and drives up labor costs.

Objectives This project creates value for the Company and its customers by: (1) modernizing the entire gas pipeline corrosion control field data collection and monitoring process; (2) eliminating the manual paper process of taking and recording measurements on corrosion control devices attached to gas pipelines; (3) automating the entire process from measurement through documentation and analysis; (4) providing an integrated solution that takes the measurements and records the results in one step; (5) implementing geographical location (latitude, longitude) mapping for each test point read to provide more efficient routing.

Scope The project scope includes: (1) purchasing hardware, connectivity, and software with related licenses needed to establish a modern electronic corrosion measurement and documentation system; (2) a data transfer to the new system from the existing system of record, Inspection Manager; and (3) training users in the use of the new system and deploy to all corrosion control technicians.

Alternatives Alternatives considered include: (1) continue with the current manual process. This option was not selected as it does not solve the issues associated with the paper-based manual process; (2) develop a Consumers Energy custom solution that would interface with a standard DVM and automate the current paper process using custom in house solution. This option was not selected as it would be far too costly and time consuming to develop in-house and a standard solution is available in the marketplace; and (3) purchase and implement a hybrid cloud-based COTS (Common Off The Shelf) hardware and software solution to provide an electronic means of data measurement and collection and then transfer that data to the existing GIS (Geographic Information System.) This option was selected as it meets the goal of automating the data collection and documentation process and eliminates the existing paper process.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/2/2022	9/30/2022	9/30/2022	12/2/2022
	In-Service/Go-Live	**Closeout**	
	5/1/2023	5/22/2023	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	$0.818	$0.489	$0.003	-	-	-	-	-	$1.310
O&M	$0.017	$0.018	-	$0.044	$0.044	$0.044	$0.044	-	$0.212
Total Cost of Ownership	$0.835	$0.507	$0.003	$0.044	$0.044	$0.044	$0.044	-	**$1.522**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	$0.025	$0.101	-	-	-	-	-	-	**$0.126**
Outside Services	$0.351	$0.251	$(0.148)	-	-	-	-	-	**$0.454**
Business Expense/Overheads	$0.014	$0.092	$0.002	-	-	-	-	-	**$0.108**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.444	$0.057	$(0.047)	-	-	-	-	-	**$0.454**
Licenses, Permits & Fees	-	$0.006	$0.197	-	-	-	-	-	**$0.203**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.835	$0.507	$0.003	-	-	-	-	-	**$1.344**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	-	$(0.200)	$(0.250)	$(0.300)	$(0.350)	$(0.400)	-	**$(1.500)**
	Initial	$0.017	$0.018	-	$0.044	$0.044	$0.044	$0.044	-	**$0.212**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.017	$0.018	$(0.200)	$(0.206)	$(0.256)	$(0.306)	$(0.356)	-	**$(1.288)**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.818	$0.489	$0.003	-	-	-	-	-	**$1.310**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.818	$0.489	$0.003	-	-	-	-	-	**$1.310**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.312

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Ability to electronically access proof of repair documentation, as well as, track repair history.
Technology Capability	Gas T&D, Generation
Intangibles	Improved compliance through reduction in errors created by the manual process.
Intangibles	Improved employee engagement by providing a modern paperless experience.
Avoided Costs	Reducing costs by eliminating revisits and rework caused by errors in the manual data entry and recording process as well as removing manual process steps.
Intangibles	Reducing errors introduced by manual data entry when technicians collect voltage readings in the field
Intangibles	The new devices have the ability to provide a geographical location (latitude, longitude) for each test point read. Employees are currently relying on test point description (description inputted by field employees)to describe our asset location. With the geographical stamp, employees will increase the accuracy of our GIS Records and also allow for more effective routing for all work types.
Avoided Costs	The new system will use Power Apps to create reports, eliminating the need for manually created reports.

Customer Order Service Tracker

Report Pulled: 11/1/2024 **Item ID: 9062**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Service Tracker, Customer Order Service Tracker

Description Short cycle orders including gas emergencies and meter services account for many of the incoming customer inquiries to the contact centers. This project will implement a service order status tracker to provide transparency to customers and oversight to internal teams supporting utility service orders across Company service areas. The tracker will provide timely and accurate service order updates, creating a more robust customer experience for tracking service order status and location-based updates.

Portfolio Customer Services > Customer Interaction Channels > Digital > Digital > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement Customers have limited visibility to when Company assigned crews will be on premise and what work will be completed. This is due to features missing within the Company's digital channels for accurate updates from dispatch, scheduling, and field crews. The lack of awareness drives calls into the call center, resulting in approximately 346,000 annual contact center calls related to short cycle requests. Additionally, this lack of visibility increases truck rolls due to dispatchers being unaware of crew locations and routes which can cause crews to be assigned when a local crew could have completed the work. This leads to overall customer dissatisfaction because of a lack of visibility to scheduled and ongoing short cycle work. Enabling a digital channel for communication regarding utility service orders will improve customer experience and reduce the waste of repetitive crew dispatching.

Objectives This project will add value to the Company and its customers by: (1) providing transparency for customers on the timing and location of the associated crew completing utility short cycle service orders, (2) reducing calls to contact centers by customers seeking clarification regarding arrival times through visibility to scheduling time-frames and providing notifications to customers when crews are en-route, (3) improving resource assignment by current location, which decreases wasted truck rolls through enabling location services for active crews, (4) increasing visibility into the service person(s) completing the order by enabling crews to connect with customers through digital channels, and (5) improving customer experience for short cycle service orders by implementing a channel of choice for Company interactions.

Scope The scope for the project includes: (1) modifying the customer self-service portal to include features that support utility service order tracking, including the location of crews en-route, (2) providing desktop and mobile capabilities, (3) enhancing the existing ServiceBench platform to allow real-time status updates that can be communicated to customers, (4) utilizing location-based services to update internal portal in real time, and (5) enabling text and email notifications to alert customers of service crews arrival times.

Alternatives Alternatives considered for this project include: (1) Deploy a mobile application to address utility service order tracking, (2) utilize a cloud hosted solution from a third-party, (3) modify the existing customer portal to enable customers and the Company to track utility service orders and crews. Options one and two were not selected as the cost associated with deployment would greatly outweigh the benefits with call reduction and improved customer experience. The third option was selected because it utilizes existing technologies, which reduces the implementation complexity and project cost and has faster value realization for the customer and the Company.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/10/2025	4/11/2025	6/13/2025	6/26/2026
	In-Service/Go-Live	**Closeout**	
	8/28/2026	11/20/2026	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	$2.413	$1.609	-	-	-	-	-	$4.022
O&M	-	$0.562	$0.375	$0.050	$0.050	$0.050	$0.050	$0.050	$1.186
Total Cost of Ownership	-	$2.975	$1.983	$0.050	$0.050	$0.050	$0.050	$0.050	**$5.208**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	$0.900	$0.600	-	-	-	-	-	**$1.500**
Outside Services	-	$1.200	$0.800	$0.050	$0.050	$0.050	$0.050	$0.050	**$2.250**
Business Expense/Overheads	-	$0.875	$0.583	-	-	-	-	-	**$1.458**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$2.975	$1.983	$0.050	$0.050	$0.050	$0.050	$0.050	**$5.208**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.562	$0.375	$0.050	$0.050	$0.050	$0.050	$0.050	**$1.186**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.562	$0.375	$0.050	$0.050	$0.050	$0.050	$0.050	**$1.186**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$2.413	$1.609	-	-	-	-	-	**$4.022**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$2.413	$1.609	-	-	-	-	-	**$4.022**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Customer Mgmt
Intangibles	Improve safety for both the Company's employees and customers by providing accurate estimated times of arrival, reducing the likelihood of threats of violence.
Intangibles	Improved customer experience related to real time updates from service crews completing activities in their area. The crews will have the ability to provide accurate estimated times of arrival and detail what work is being completed via digital channels. Building trust between the Company and its customers regarding the work being completed correctly, the first time a crew arrives.
Avoided Costs	Reduce Truck Rolls for appointments that weren't rescheduled in a timely manner and limiting truck rolls in locations where a crew can complete multiple jobs in a geographic location. Each avoided truck roll saves the company approximately $450.
Avoided Costs	Reduction in calls to validate arrival times of field crews based on more clarity and transparency regarding the service being completed. Currently 346,000 calls take place yearly regarding status of service orders. The project anticipates a 60% reduction over three years resulting in potential avoided costs of $537,996 per year. (Avg cost per call $7.63 [$9.76/call internal & $5.50/call H&H] * 69,000 calls reduced each year.)
Intangibles	Reduction in Customer Complaints regarding service orders, delays in service, and maintenance visits. Last year, the company received 6 formal complaints and 11 informal complaints regarding non-emergency maintenance work.

Customer Self-Service Online Work Scheduling

Report Pulled: 11/1/2024 **Item ID: 9035**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Online Work Scheduling, Customer Self-Service Online Work Scheduling

Description The Online Work Scheduling project will implement online, self-service work order scheduling for new business requests enabling future work requests to be scheduled online by customers new business requests, rather than contacting the contact center.

Portfolio Customer Services > Customer Interaction Channels > Digital > Digital > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement

Currently customers must call the contact center to schedule work and obtain updates given a lack of online self-service capabilities. To stay informed, customers are required to contact the contact center, and often requires multiple calls per work request. In addition, once work is completed customers do not receive confirmation that the work has been completed or what work was completed, which may also result in additional inbound customer calls. These inefficiencies require multiple inbound calls, which often results in customer dissatisfaction.

Objectives

The Company and its customer will see value through this project by: (1) implementing self-service capabilities for customers to submit new business requests, (2) reducing calls into contact centers, (3) improving the digital experience within the Company's customer portal, (4) improving quality of utility service work through timely customer surveys based on work completed, (5) improving work efficiency by providing routine updates online resulting in manual activity (6) improving overall customer experience as customers can utilize channel of choice, and (7) enabling future initiatives supporting customer site work by developing the technical and business process foundation for other initiatives to expand upon.

Scope

The project scope includes: (1) creating the ability for customer self-service online for new business requests, (2) enabling channel of choice options for scheduled work order confirmation notifications, and (3) automating scheduling of work orders in SAP and other back-end systems.

Alternatives

Alternatives considered include: (1) developing a form on the Company's web portal for customers to complete and send to a monitored email box, (2) purchasing a third party cloud solution to host a portal for customers to schedule work orders, (3) displaying a map of service areas with a number for customers to call their local dispatch area, and (4) enhancing the current customer self-service portal to include new business requests. The first and third alternatives were not selected because they will degrade the customer experience and require additional manual process steps and work, introducing waste to manage additional processes to schedule the work order. The second alternative was not selected due to the high cost of integrating a new solution with the existing customer platform and back-end systems and increases ongoing maintenance and support costs. The fourth alternative was selected because it improves customer experience through self-service, utilizes the existing customer self-service portal, increases process efficiency for scheduling work orders, and minimizes increases for ongoing maintenance and support costs.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/10/2023	2/28/2023	3/28/2023	5/25/2023
	In-Service/Go-Live	**Closeout**	
	8/15/2023	8/22/2023	

FUNDING SUMMARY

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Cap+COR	$0.681	$1.145	$0.020	-	-	-	-	-	$1.846
O&M	$0.178	$0.102	$0.000	-	$0.020	$0.020	-	-	$0.320
Total Cost of Ownership	$0.859	$1.248	$0.020	-	$0.020	$0.020	-	-	**$2.166**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.267	$0.122	-	-	-	-	-	-	**$0.389**
Outside Services	$0.555	$1.032	-	-	-	-	-	-	**$1.586**
Business Expense/Overheads	$0.036	$0.052	-	-	-	-	-	-	**$0.088**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.001	$0.042	$0.020	-	-	-	-	-	**$0.062**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.859	$1.248	$0.020	-	-	-	-	-	**$2.126**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2021	2022	2023	2024	2025	2026	2027	2028 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.178	$0.102	$0.000	-	$0.020	$0.020	-	-	**$0.320**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.178	$0.102	$0.000	-	$0.020	$0.020	-	-	**$0.320**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.681	$1.145	$0.020	-	-	-	-	-	**$1.846**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.681	$1.145	$0.020	-	-	-	-	-	**$1.846**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Customer Management

Data & Analytics Platform Rationalization

Report Pulled: 11/1/2024 **Item ID: 13961**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Data & Analytics Platform Rationalization

Description This project will optimize the Data & Analytics system landscape by creating connections, migrating data into Data Lake 2.0 (DL 2.0), and building visualizations from the data in DL 2.0. Following the enablement of DL 2.0, retirement of the IT Data & Analytics legacy systems including SingleStore Data Lake (SSDL), SAP Business Warehouse (BW), SAP Business Objects (BOBJ), Native HANA, the BW Portal, and SAP Business Objects Data Services (BODS) creates value by reducing the total cost of ownership associated with maintaining and supporting legacy systems.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement The IT Data & Analytics legacy systems (SSDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BODS) are outdated, inefficient, and becoming duplicative in nature with the introduction of DL 2.0. If these legacy systems are not retired, they will continue to cost the Company money as major investments are needed to maintain and support them.

Objectives This platform rationalization project creates value for the Company and its customers by reducing the total cost of ownership associated with maintaining and supporting legacy systems including licensing fees, maintenance costs, infrastructure, and support resources.

Scope The project scope includes: (1) the assessment of the existing Data & Analytics platforms including SSDL, SAP BW, SAP BOBJ, Native HANA, the BW Portal, and BODS; (2) inventory of data and reports still being used by stakeholders; (3) determination of migration strategy; (4) data migration to the Azure Data Lake; (5) report migration to Power BI; (6) organization change management; and (7) the retirement/decommissioning of the legacy platforms and applications.

Alternatives Alternatives considered: (1) upgrade legacy systems in place (on-premise). This alternative was not selected because this is costly and misaligned with the Company's cloud strategy. (2) Lift and shift these on-premise systems to the cloud through the Hybrid Cloud Transformation Program. This alternative was not selected because it would duplicate the work being done as part of the DL 2.0 project and would not provide the same efficiencies that DL 2.0 introduces. The alternative to migrate all data sources to DL 2.0 and retire legacy systems was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
3/3/2025	4/28/2025	5/30/2025	7/31/2026
	In-Service/Go-Live	**Closeout**	
	8/14/2026	9/18/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$6.638	$3.364	-	-	-	-	-	-	$10.002
O&M	$1.308	$0.853	-	-	-	-	-	-	$2.161
Total Cost of Ownership	$7.946	$4.217	-	-	-	-	-	-	**$12.163**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.667	$0.333	-	-	-	-	-	-	**$1.000**
Outside Services	$6.670	$3.330	-	-	-	-	-	-	**$10.000**
Business Expense/Overheads	$0.309	$0.154	-	-	-	-	-	-	**$0.463**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.100	$0.100	-	-	-	-	-	-	**$0.200**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$7.746	$3.917	-	-	-	-	-	-	**$11.663**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	$(0.610)	$(3.028)	$(2.427)	$(2.436)	$(2.445)	$(2.454)	-	-	**$(13.399)**
	Initial	$1.308	$0.853	-	-	-	-	-	-	**$2.161**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.698	$(2.175)	$(2.427)	$(2.436)	$(2.445)	$(2.454)	-	-	**$(11.239)**
Cap+COR	Reduction	$(0.300)	-	$(2.000)	$(2.000)	-	-	-	-	**$(4.300)**
	Initial	$6.638	$3.364	-	-	-	-	-	-	**$10.002**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$6.338	$3.364	$(2.000)	$(2.000)	-	-	-	-	**$5.702**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall)	0.151

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Attraction and Retention of High Performing	Medium	Medium	By retiring legacy systems and shifting to industry leading technologies (Microsoft Azure), the Company can attract and retain talent.
Inaccuracy of Financial and Operational Rep	Medium	High	Due to limitations with legacy systems, system outages will continue to happen regularly which impact reporting metrics for many areas across the organization including potential impacts to month end close and Operations operating review metrics. As of May 2024, there have been six SAP BW/SAP BOBJ outages that impacted critical reporting.

OTHER VALUE

Type	Description
Technology Capability	Investment Planning and Project Mgmt: Investment Analysis

Digital-Cloud Data and Analytics Platform

Report Pulled: 11/1/2024 **Item ID: 13443**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Accelerate Data Strategy, Digital-Cloud Data and Analytics Platform

Description This project will provide Artificial Intelligence (AI) and analytics in the cloud across the business to uncover new paths to value, faster, allowing the organization to make better decisions and enable delivery outcomes for the NGDP, Electric Grid Integration, customer programs, and other business needs. The project will additionally establish data governance roles and responsibilities, processes, and implement tools to support best practices across the enterprise.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement Consumers Energy faces several challenges in the ongoing data modernization journey, which include: (1) legacy data platform operations; (2) long lead times for data exploration and identification of data assets; (3) lack of data ownership and quality, (4) limited data governance best practices across data ownership, access control & security; and (5) heavy dependence on IT for Business Intelligence reporting and analytics.

Objectives The project will add value by providing data to support business needs by: (1) optimizing data platform operations costs with workflow-based platform infrastructure deployment using pre-built modules and templates; (2) reducing data operations build complexity and data engineering costs through automation; (3) improving data quality and governance that leads to reduced costs of data provisioning, data duplication, and improved data accuracy; (4) streamlining data access requests, management, and governance to reduce risks and support efficiency; and (5) increasing the speed to deliver new data and data capabilities, improving productivity, and improving access to data. This project is an enabler for business areas to use these capabilities to build analytic models for asset and labor optimization that is anticipated to more than offset the project costs.

Scope The project scope includes: (1) developing and modernizing the analytics platform in the cloud to allow Consumers Energy to implement new use cases leveraging simplified infrastructure configurations and automated deployment processes; (2) build and deploy data management capabilities, controls, catalog, assets, and data flow; (3) developing data ordering workflows and data access management controls; (4) prioritization and new datasets; (5) simplifying infrastructure configuration; (6) automating deployment processes; (7) enabling data governance tools and processes.

Alternatives Alternatives considered include: (1) Address current pain points in existing on-premise and cloud analytics platforms. This alternative was not selected because the existing platforms requires new investment in licensing and infrastructure, delivery for new capabilities cannot keep pace with demand, still requires investment to address legacy system technical obsolescence, and business areas would not realize asset and labor optimizations. (2) Continue to utilize existing on-premise and cloud analytics platforms. This alternative was not selected because it would not address the current pain points in the existing on-premise and cloud analytics platforms, limiting the Company's ability to have required data and analytics capabilities to improve processes and realize asset and labor optimizations. (3) Implement a new data and analytics platform in the cloud. This alternative was selected because it provides improved analytics capabilities, faster access to data that is critical to improve business process, and reduces technical obsolescence.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
5/1/2023	5/1/2023	6/5/2023	7/31/2023
	In-Service/Go-Live	**Closeout**	
	7/31/2023	12/6/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$3.342	$8.921	-	-	-	-	-	-	$12.263
O&M	$0.197	$1.233	$1.588	$1.588	$1.588	-	-	-	$6.194
Total Cost of Ownership	$3.539	$10.155	$1.588	$1.588	$1.588	-	-	-	**$18.457**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.726	$1.668	-	-	-	-	-	-	**$2.393**
Outside Services	$1.912	$7.133	-	-	-	-	-	-	**$9.045**
Business Expense/Overheads	$0.253	$0.363	$0.084	$0.084	$0.084	-	-	-	**$0.869**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.648	$0.991	-	-	-	-	-	-	**$1.639**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$3.539	$10.155	$0.084	$0.084	$0.084	-	-	-	**$13.947**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.197	$1.233	$1.588	$1.588	$1.588	-	-	-	**$6.194**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.197	$1.233	$1.588	$1.588	$1.588	-	-	-	**$6.194**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$3.342	$8.921	-	-	-	-	-	-	**$12.263**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$3.342	$8.921	-	-	-	-	-	-	**$12.263**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Automated deployments for infrastructure decreases build time and increases time spent on higher value work for the IT platform team. This will also decrease future project implementation hours and associated labor costs. Avoided benefits will be finalized following phase 1.
Intangibles	Enhance Workplace Productivity and Collaboration: Improve Analytics Efficacy and time to insights with data catalog and data democratization.
Risk Mitigation	Reduce Data compliance Risk and Exposure: Reduced exposure to data loss, compliance risk, or potential for data platform interruption with integrated data catalog, controls and governance.

Digital-Data and Analytics in the Cloud

Report Pulled: 11/1/2024 **Item ID: 8804**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Data and Analytics in the Cloud, Digital - Data and Analytics in the Cloud, Digital-Data and Analytics in the Cloud

Description This project will extend the current data and analytics environment into a cloud environment, which will enable data and analytics at-scale and enable the delivery of outcomes for the Natural Gas Delivery Plan, Electric Grid Integration, customer programs, and other business needs.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-PROD TRANSF, ARCH & QUAL

WORK OBJECTIVES

Problem Statement The Company currently has an on-premise data and analytics platform, Data Lake, that houses multiple data attributes ranging from customer, grid, and operations. As the Company requires more predictive and prescriptive analytical use case outcomes, the current environment is insufficient to handle the data analytics at-scale for multiple use cases. Also, the current solution lacks the libraries of advanced Machine Learning (ML), AI tools, and Industry-Standard Big Data Ingestion tools, which are standard offerings as part of Cloud environments, such as Amazon Web Services (AWS), Azure or Google Cloud Platforms.

Objectives The project will add value by: (1) establishing the technical foundation necessary to scale the platform, which enables data analytics at-scale for the identified use cases; (2) establishing ML workspaces in the cloud that enable predictive and prescriptive analytics at-scale for the identified use cases; (3) gain performance efficiencies for analytics and data capability execution in cloud, reducing wait time and lag for analytics teams; (4) enabling pay-per-use, which enables future cost optimization for the data analytics platform; and (5) empowering faster prototyping, testing, and deployment of analytics solutions.

Scope The project scope Includes: (1) introducing new data sets, including historical data, to enable Data Analytics use cases in the cloud; (2) implementing cloud-based Machine Learning (ML) and Artificial Intelligence (AI) capabilities; (3) integrating the agile DevOps toolset with the cloud-based data and analytics platform to enable future automation; (4) implementing capabilities to enable capacity-based pay-per-use; and (5) defining and implementing cloud-based data and analytics platform infrastructure that will enable future cloud migration and maintenance.

Alternatives The alternative considered to a cloud solution is to expand the on-premise infrastructure and purchase multiple tools to solve individual capability gaps. The Company did not choose this alternative because it is more costly than cloud due to higher infrastructure costs and a larger workforce required for implementation.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
7/1/2022	8/1/2022	11/1/2022	1/4/2023
	In-Service/Go-Live	**Closeout**	
	10/31/2023	12/30/2023	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	-	$0.502	-	-	-	-	-	-	$0.502
O&M	$0.043	$0.125	-	-	-	-	-	-	$0.169
Total Cost of Ownership	$0.043	$0.627	-	-	-	-	-	-	**$0.670**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	$0.017	$0.220	-	-	-	-	-	-	**$0.238**
Outside Services	$0.023	$0.297	-	-	-	-	-	-	**$0.320**
Business Expense/Overheads	$0.003	$0.095	-	-	-	-	-	-	**$0.098**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.015	-	-	-	-	-	-	**$0.015**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.043	$0.627	-	-	-	-	-	-	**$0.670**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.043	$0.125	-	-	-	-	-	-	**$0.169**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.043	$0.125	-	-	-	-	-	-	**$0.169**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.502	-	-	-	-	-	-	**$0.502**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.502	-	-	-	-	-	-	**$0.502**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	Foundational analytics capabilities enable the outcome of the Natural Gas delivery plan, Electric Grid Integration plan, and the Retail plan. If the Company is unable to quickly deliver foundational analytics capabilities it risks the outcomes of the strategic plans.
Intangibles	Implementation of the Data and Analytics in the Cloud will allow for routine upgrades and seamless integration of new analytic tools and libraries available within the cloud. This allows for quicker delivery of analytics for projects.
Intangibles	Implementation of the Data and Analytics in the Cloud will allow for the ability to quickly scale up compute power needed to run advanced analytics. Today, average time to purchase and expand on-premise hardware is between 3-6 months. That is 3-6 months that we are missing out on business value.

Digital-Hybrid Cloud and Data Center Migration

Report Pulled: 11/1/2024 **Item ID: 10502**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Hybrid Cloud and Data Center Migration, Digital - Hybrid Cloud and Data Center Migration, Digital-Hybrid Cloud and Data Center Migration

Description This project will optimize data center assets and asset replacement project purchases by migrating or retiring applications out of existing Company and co-location data centers into cloud services, reducing operational costs for running IT services and leveraging increased cloud capabilities to improve the efficiency, quality, and speed-to-market of customer-facing and internal IT services.

Portfolio IT Services > Infrastructure > Data Center - Enterprise Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement The technology currently deployed in the Company's data centers meets many customers' needs today. However, the pace of digital transformation is increasing rapidly, and requirements for applications are evolving faster than the technology in the Company's data centers can respond in a cost-effective manner. These data center constraints lead to longer implementation times, missing capabilities, or reduced functionality in the applications that the Company can deploy.

Objectives This project will create value by ensuring the Company's technology requirements are met through a comprehensive and cost-effective combination of data centers and public cloud services. Specifically, by migrating applications to cloud services, the project will: (1) reduce capacity, hardware maintenance, and security device costs at the co-location data center; (2) reduce hardware maintenance and security device costs at the production data center; (3) enable the ability to scale infrastructure quickly up or down without costly up-front hardware purchases; (4) reduce application risk through cost-effective, scalable infrastructure redundancy and availability; (5) reduce ongoing server and storage asset replacement costs; (6) reduce ongoing networking equipment replacement costs; (7) reduce operational support costs; and (8) enable the use of a vast array of cloud services to support Company applications.

Scope The project scope includes: (1) promoting the robust main co-location data center to become the primary data center for on-premise IT services; (2) demoting the Company's production data center to the disaster recovery data center for on-premise IT services; (3) analyzing applications for migration to cloud or retirement; (4) migrating applications from on-premise to cloud; (5) transforming applications to use cost-effective cloud services; (6) altering network architecture and deploying base infrastructure to allow each location (on-premise or in cloud) to function independently; (7) deploying cloud and on-premise cost management tooling and processes; (8) simplifying and optimizing backup and disaster recovery resources and processes using cloud services; (9) implementing additional automation for application deployment and management; (10) changing the operations model for support of cloud-based applications; (11) educating and increasing the skills of IT and other employees in leveraging public cloud services; and (12) transforming IT to become the broker of cloud services for the Company.

Alternatives Alternatives considered included: (1) migrating to public cloud services faster. This alternative was not chosen because the Company's ability to absorb new technologies coupled with the investments the Company has already made in data center equipment would prevent a faster move from being efficient and effective, introducing additional financial risk; (2) migrating to public cloud services slower or not at all. This alternative was not selected because delaying public cloud services and capabilities coupled with requiring an extension of the life of existing data center equipment creates increased financial and operational risk; and (3) contracting with an outside vendor to provide cloud services to run applications for the Company. This alternative was not selected because industry information shows the option as not yet cost effective or not providing a maturity level that the Company would be able to easily consume with limited in-house experience and expertise in public cloud. The alternative to migrate to a hybrid cloud and data center model was selected because of the expected cost benefits and technology capabilities it provides to the Company over a timeline that allows the Company to realize the value of existing investments.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/1/2023	4/15/2023	8/15/2023	10/1/2025
	In-Service/Go-Live	**Closeout**	
	12/1/2025	12/15/2025	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	-	$2.779	$2.321	$1.776	-	-	-	-	$6.876
O&M	-	$0.529	$0.728	$10.910	$10.188	$10.450	$9.620	$20.082	$62.507
Total Cost of Ownership	-	$3.308	$3.049	$12.686	$10.188	$10.450	$9.620	$20.082	**$69.383**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	-	$0.372	$0.949	$1.510	-	-	-	-	**$2.831**
Outside Services	-	$1.062	$1.692	-	-	-	-	-	**$2.754**
Business Expense/Overheads	-	$0.157	$0.241	$0.667	-	-	-	-	**$1.065**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.379	$(0.136)	-	-	-	-	-	**$0.242**
Licenses, Permits & Fees	-	$1.339	$0.303	$2.030	$1.100	$1.100	-	-	**$5.872**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$3.308	$3.049	$4.206	$1.100	$1.100	-	-	**$12.764**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	$(0.623)	$(1.382)	$(4.223)	$(6.008)	$(6.188)	$(6.374)	$(12.068)	**$(36.866)**
	Initial	-	$0.529	$0.728	$10.910	$10.188	$10.450	$9.620	$20.082	**$62.507**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$(0.094)	$(0.654)	$6.686	$4.180	$4.262	$3.246	$8.014	**$25.640**
Cap+COR	Reduction	-	$(5.624)	$(2.677)	$(3.155)	$(5.820)	$(5.995)	$(4.175)	$(12.910)	**$(40.356)**
	Initial	-	$2.779	$2.321	$1.776	-	-	-	-	**$6.876**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$(2.845)	$(0.356)	$(1.379)	$(5.820)	$(5.995)	$(4.175)	$(12.910)	**$(33.479)**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	0.172

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative and General Support
Risk Mitigation	Consumption of public cloud services offers infrastructure redundancy and availability at scale that cannot be duplicated in the Company's data centers, reducing the risk of running applications.
Intangibles	This project makes consumption of all types of public cloud resources possible to provide IT services in support of all business processes, enabling technology capabilities for Administrative and General Support.
Avoided Costs	With applications running in public cloud, the Company can expand and contract the consumption of IT services at will as appropriate versus purchasing hardware to expand in quantity and having no simple ability to contract.

Energy Assistance Enhancements and Maintenance Annual U Report Pulled: 11/1/2024 Item ID: 6683

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - Interval **Work Type** Project

Alias CARE 5.0, Consumers Affordable Resource for Energy (CARE) Annual Updates, Energy Assistance Enhancements and Maintenance Annual Updates

Description The Energy Assistance Enhancements and Maintenance Annual Updates project, formerly known as Consumers Affordable Resource for Energy (CARE) project, will implement software changes to offer energy assistance to low-income customers and streamline the process for the assistance agencies who use the assistance portal. This is accomplished through improved user interfaces and updates to SAP to process various requests. Upcoming modifications will be identified following an ongoing and annual review of requests, that includes criteria from the Department of Health and Human Services (DHHS) and Michigan Public Service Commission (MPSC) to prioritize the list of changes.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement Each grant year, DHHS and MPSC stipulate the criteria required for customers to enroll in the CARE program, how the Company and agencies will manage the enrollment process and track active CARE customers, and how they will administer the Michigan Energy Assistance Program (MEAP) benefits through bill credits and arrears forgiveness. The criteria changes significantly each year; therefore, the Energy Assistance Enhancement and Maintenance Annual Updates application requires modifications to meet the new requirements. If the regulatory requirements are not fulfilled, the Company is at risk of losing state Low Income Energy Assistance Fund (LIEAF) funds to assist low-income customers with paying their energy bills, thereby increasing the customers risk of shutoff for non-payment. In addition, our energy assistance programs function within all software platforms in the company which consistently need enhancements and updates.

Objectives The project will provide the following value: (1) complete modifications to internal SAP application and Agency Portal to receive LIEAF funding, which can be used to provide customers the bill credits and arrears forgiveness; (2) improve the data within the assistance agencies portal, thereby making it easier to assist customers in need of LIEAF funding; and (3) complete modifications to customer facing platforms.

Scope The project scope includes: (1) updating the enrollment and status process; (2) allowing for flat monthly bills; (3) improving reporting; (4) updating the arrears forgiveness plan; (5) satisfying additional regulatory requirements for the annual grant rule changes required by the Department of Health and Human Services and Michigan Public Service Commission; (6) updating CARE dunning process; and (7) updating the assistance portal (CE PASS) functionality to enhance Agency Self-Service.

Alternatives Alternatives considered include: (1) continue with current process. This alternative was not chosen because it would lead to loss of grant funding, thus decreasing or eliminating energy assistance dollars for customers; (2) transfer administration of Energy Assistance Programs to a third party organization. This alternative was not selected because it would remove ownership and visibility into the health of the program while increasing administrative costs; and (3) make annual updates to the application, which will allow agencies to easily enroll customers on assistance programs and allow placement of holds to stop or prolong credit activity until assistance decisions are granted. This option was selected since it provides long-term proactive energy assistance to customers and prevents loss of grant funds. Changes are required to internal systems such as SAP, a large internal system that supports broad areas of the business, and the Agency Portal, an internally developed web application, therefore a single cloud or third-party alternative is not viable. Additionally, retiring the existing Agency Portal for a new application would increase costs beyond that of the routine upgrades.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.222	$0.349	$0.333	$0.333	$0.333	$0.333	$0.333	-	$2.234
Total Cost of Ownership	$0.222	$0.349	$0.333	$0.333	$0.333	$0.333	$0.333	-	**$2.234**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.109	$0.233	$0.284	$0.284	$0.284	$0.284	$0.284	-	**$1.763**
Outside Services	$0.101	$0.108	$0.026	$0.026	$0.026	$0.026	$0.026	-	**$0.341**
Business Expense/Overheads	$0.013	$0.008	$0.022	$0.022	$0.022	$0.022	$0.022	-	**$0.130**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.222	$0.349	$0.333	$0.333	$0.333	$0.333	$0.333	-	**$2.234**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.222	$0.349	$0.333	$0.333	$0.333	$0.333	$0.333	-	**$2.234**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.222	$0.349	$0.333	$0.333	$0.333	$0.333	$0.333	-	**$2.234**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	As a result of our compliance with CARE requirements, we have access to MEAP funds that help to pay down low-income customer's arrears, therefore preventing those from being written off. This year, we are expecting to enroll 9,350 customers with an average arrears of $285, thus potentially avoiding $2.6M in bad debt write-offs.
Risk Mitigation	As a result of our compliance with CE PASS requirements, Department of Health and Human Service and other agencies would not be able to assist our customers. This could result in $60-$70 million dollars not able to be funded to the company.
Technology Capability	Customer Management - As a result of this project, we will better be able to manage our customers who otherwise would fall behind on bills.

Enhancements - Customer Experience and Operations- Cap

Report Pulled: 11/1/2024 **Item ID: 8776**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Enhancements - Customer Experience and Operations- O&M, Enhancements - Customer Experience and Operations- Cap

Description The Enhancements – Customer Experience – Operations project provides funding for small changes and improvements to existing software to address requests needed due to changing business requirements.

Portfolio IT Services > Applications > Customer Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface requiring smaller effort software application changes. These software enhancements are neither projects nor operational work but require funding for resources. The annual budget cycle should ensure funding is provided for software enhancement small work efforts to ensure we are leveraging the value of existing IT investments to support business processes.

Objectives Requests for this funding are governed by a cross-functional board of representatives from each area which meets monthly to evaluate and prioritize the work. The board assesses requests for value using benefits that are categorized into hard cost savings, cost avoidance, safety, achieving corporate goals, and mitigating risk. Included in the implementation are small changes and functionality improvements to existing software application investments for Customer Experience and Operations.

Scope The enhancement requests are fulfilled to provide functionality for areas such as dunning, customer billing, programs for low income customers (i.e. Winter Protection Program, Special Protection Program), Company website, contact center, energy efficiency, and rates.

Alternatives Historically, specific budget was not allocated for enhancements work requiring efforts to identify funding for each request. As part of our review process the alternative considered was to not provide funding for enhancements. However, this limits our ability to make software changes to support process improvements, regulatory changes, and to meet legally required system changes.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.799	$0.517	-	-	-	-	-	-	$1.315
O&M	$0.076	$0.024	-	-	-	-	-	-	$0.100
Total Cost of Ownership	$0.875	$0.541	-	-	-	-	-	-	**$1.416**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.309	$0.279	-	-	-	-	-	-	**$0.588**
Outside Services	$0.332	$0.209	-	-	-	-	-	-	**$0.541**
Business Expense/Overheads	$0.195	$0.053	-	-	-	-	-	-	**$0.247**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.027	-	-	-	-	-	-	-	**$0.027**
Licenses, Permits & Fees	$0.013	-	-	-	-	-	-	-	**$0.013**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.875	$0.541	-	-	-	-	-	-	**$1.416**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.076	$0.024	-	-	-	-	-	-	**$0.100**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.076	$0.024	-	-	-	-	-	-	**$0.100**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.799	$0.517	-	-	-	-	-	-	**$1.315**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.799	$0.517	-	-	-	-	-	-	**$1.315**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description

Enhancements-Cloud Automation

Report Pulled: 11/1/2024 **Item ID: 8806**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Cloud Automation Phase 6m, Enhancements - Cloud Automation, Enhancements-Cloud Automation

Description The Enhancements - Cloud Automation project provides funding for small changes and improvements to existing software to address requests needed due to changing business requirements.

Portfolio IT Services > Infrastructure > Data Center - Enterprise Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ENTERPRISE PRODUCTS AND SEI

WORK OBJECTIVES

Problem Statement The Company's existing cloud automation platform consists of a number of scripts that automate the build of infrastructure such as servers, operating systems, databases, and application installations in minutes or hours. These scripts include security hardening and application of the latest patches. This project will maintain and improve these scripts to ensure they meet the latest security policy and requirements, and any changes to the way the operating systems, databases, or applications are configured.

Objectives The value of this enhancement project is the implementation of small changes and functionality improvements to existing IT software application investments for Cloud Automation such as cost avoidance of 70 hours per year by removing failed build release tickets and 120 hours per year on Windows and Linux template patching improvements, safety, achieving corporate goals, and mitigating risk.

Scope The scope of the enhancement includes requests that will be fulfilled to provide functionality for areas such as automating IT servers, firewall set-ups, etc.

Alternatives The alternative would be to continue as is with existing scripts; however, this introduces security risks and additional manual steps to build infrastructure, which in turn, will lead to increased costs and risk of manual errors.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.315	-	-	-	-	-	-	-	$0.315
O&M	$0.191	-	-	-	-	-	-	-	$0.191
Total Cost of Ownership	$0.505	-	-	-	-	-	-	-	**$0.505**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.185	-	-	-	-	-	-	-	**$0.185**
Outside Services	$0.033	-	-	-	-	-	-	-	**$0.033**
Business Expense/Overheads	$0.123	-	-	-	-	-	-	-	**$0.123**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.164	-	-	-	-	-	-	-	**$0.164**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.505	-	-	-	-	-	-	-	**$0.505**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.191	-	-	-	-	-	-	-	**$0.191**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.191	-	-	-	-	-	-	-	**$0.191**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.315	-	-	-	-	-	-	-	**$0.315**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.315	-	-	-	-	-	-	-	**$0.315**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Automation is a foundational digital capability that supports the destination strategies for Retail, Gas, Electric, and Digital, identified in Consumers Energy's ten year destination plan. The automation work in this project will directly support and enhance this capability for Consumers Energy.
Intangibles	Each enhancement must define benefits that are reflected in the request value score.

Enhancements-Corporate Services-O&M

Report Pulled: 11/1/2024 **Item ID: 11155**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Application Currency and Enhancements – Corporate Services - Capital, Application Currency – Corporate Services - O&M, Enhancements – Corporate Services - Capital, Enhancements – Corporate Services - O&M, Enhancements-Corporate Services-O&M

Description The Corporate Services initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-PLANNING & GOV

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services.

Scope

The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs.

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.041	-	-	-	-	-	-	-	$0.041
Total Cost of Ownership	$0.041	-	-	-	-	-	-	-	**$0.041**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.012	-	-	-	-	-	-	-	**$0.012**
Outside Services	$0.026	-	-	-	-	-	-	-	**$0.026**
Business Expense/Overheads	$0.002	-	-	-	-	-	-	-	**$0.002**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.041	-	-	-	-	-	-	-	**$0.041**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.041	-	-	-	-	-	-	-	**$0.041**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.041	-	-	-	-	-	-	-	**$0.041**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Enhancements-CX&O-Capital

Report Pulled: 11/1/2024 **Item ID: 11374**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Application Currency and Enhancements - CE&O - Capital, Application Currency - CE&O - Capital, Enhancement - CE&O - Capital, Enhancements - CE&O - Capital, Enhancements-CE&O-Capital, Enhancements-CX&O-Capital

Description The CX&O initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in the CX&O Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments for CX&O. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience Operations, Applications Support and, Device Management.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.896	-	-	-	-	-	-	-	$0.896
O&M	$0.146	-	-	-	-	-	-	-	$0.146
Total Cost of Ownership	$1.042	-	-	-	-	-	-	-	**$1.042**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.109	-	-	-	-	-	-	-	**$0.109**
Outside Services	$0.652	-	-	-	-	-	-	-	**$0.652**
Business Expense/Overheads	$0.280	-	-	-	-	-	-	-	**$0.280**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.002	-	-	-	-	-	-	-	**$0.002**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$1.042	-	-	-	-	-	-	-	**$1.042**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.146	-	-	-	-	-	-	-	**$0.146**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.146	-	-	-	-	-	-	-	**$0.146**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.896	-	-	-	-	-	-	-	**$0.896**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.896	-	-	-	-	-	-	-	**$0.896**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Enhancements-CX&O-O&M

Report Pulled: 11/1/2024 **Item ID: 11375**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Applications Currency and Enhancements - CE&O - O&M, Application Currency and Enhancements - CE&O - O&M, Application Currency - CE&O - O&M, Enhancements - CE&O - O&M, Enhancements-CE&O-O&M, Enhancements-CX&O-O&M

Description The CX&O initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements in the CX&O Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope

Included in the implementation are small changes and functionality improvements to existing IT software application investments for CX&O. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience Operations, Applications Support and, Device Management.

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.146	$0.185	-	-	-	-	-	-	$0.331
Total Cost of Ownership	$0.146	$0.185	-	-	-	-	-	-	**$0.331**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.046	$0.098	-	-	-	-	-	-	**$0.143**
Outside Services	$0.094	$0.083	-	-	-	-	-	-	**$0.177**
Business Expense/Overheads	$0.006	$0.004	-	-	-	-	-	-	**$0.010**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.146	$0.185	-	-	-	-	-	-	**$0.331**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.146	$0.185	-	-	-	-	-	-	**$0.331**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.146	$0.185	-	-	-	-	-	-	**$0.331**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Customer Management
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Enhancements-IT-Capital

EXECUTIVE SUMMARY

Report Pulled: 11/1/2024 **Item ID: 11332**

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias Enhancements - TSM, Application Currency and Enhancements - Infrastructure Applications and Operations - O&M, Enhancements - Infrastructure Applications and Operations - Capital, Enhancements - IAO - Capital, Enhancements - IT - Capital, Enhancements-IT-Capital

Description The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Infrastructure > Network Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ENTERPRISE PRODUCTS AND SER

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope

Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management.

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.168	$0.040	-	-	-	-	-	-	$0.208
O&M	$0.000	-	-	-	-	-	-	-	$0.000
Total Cost of Ownership	$0.168	$0.040	-	-	-	-	-	-	**$0.208**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.045	$0.014	-	-	-	-	-	-	**$0.059**
Outside Services	$0.057	-	-	-	-	-	-	-	**$0.057**
Business Expense/Overheads	$0.064	$0.026	-	-	-	-	-	-	**$0.090**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.002	$0.000	-	-	-	-	-	-	**$0.002**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.168	$0.040	-	-	-	-	-	-	**$0.208**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.000	-	-	-	-	-	-	-	**$0.000**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.000	-	-	-	-	-	-	-	**$0.000**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.168	$0.040	-	-	-	-	-	-	**$0.208**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.168	$0.040	-	-	-	-	-	-	**$0.208**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Enhancements-IT-O&M

EXECUTIVE SUMMARY

Report Pulled: 11/1/2024 **Item ID: 11334**

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias Enhancements - TSM, Application Currency and Enhancements - Infrastructure Applications and Operations - O&M, Enhancements - Infrastructure Applications and Operations - Capital, Enhancements - IAO - Capital, Enhancements - IAO - O&M, Enhancements - IT - O&M, Enhancements-IT-O&M

Description The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Infrastructure > Network Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ENTERPRISE PRODUCTS AND SER

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope

Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management.

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.073	$0.004	-	-	-	-	-	-	$0.077
Total Cost of Ownership	$0.073	$0.004	-	-	-	-	-	-	**$0.077**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.009	-	-	-	-	-	-	-	**$0.009**
Outside Services	$0.057	$0.003	-	-	-	-	-	-	**$0.060**
Business Expense/Overheads	$0.003	$0.000	-	-	-	-	-	-	**$0.003**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.004	-	-	-	-	-	-	-	**$0.004**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.073	$0.004	-	-	-	-	-	-	**$0.077**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.073	$0.004	-	-	-	-	-	-	**$0.077**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.073	$0.004	-	-	-	-	-	-	**$0.077**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Enhancements-Operations-Capital

Report Pulled: 11/1/2024 **Item ID: 11325**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Application Currency and Enhancements - Operations - Capital, Enhancements - Operations - Capital, Enhancements-Operations-Capital

Description The Operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-OPERATIONS

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in the Operations Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments for Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.599	$0.201	-	-	-	-	-	-	$0.800
O&M	$0.028	$0.003	-	-	-	-	-	-	$0.031
Total Cost of Ownership	$0.626	$0.204	-	-	-	-	-	-	**$0.830**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.157	$0.199	-	-	-	-	-	-	**$0.355**
Outside Services	$0.258	$0.005	-	-	-	-	-	-	**$0.263**
Business Expense/Overheads	$0.203	$0.015	-	-	-	-	-	-	**$0.218**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.009	-	-	-	-	-	-	-	**$0.009**
Licenses, Permits & Fees	-	$(0.014)	-	-	-	-	-	-	**$(0.014)**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.626	$0.204	-	-	-	-	-	-	**$0.830**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.028	$0.003	-	-	-	-	-	-	**$0.031**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.028	$0.003	-	-	-	-	-	-	**$0.031**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.599	$0.201	-	-	-	-	-	-	**$0.800**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.599	$0.201	-	-	-	-	-	-	**$0.800**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Enhancements-Operations-O&M

Report Pulled: 11/1/2024 **Item ID: 11327**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Enhancements - Operations - O&M, Application Currency and Enhancements - Operations - O&M, Enhancements - Operations - O&M, Enhancements-Operations-O&M

Description The Operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-OPERATIONS

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements in the Operations Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Operations.

Scope

The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls.

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.132	$0.248	-	-	-	-	-	-	$0.380
Total Cost of Ownership	$0.132	$0.248	-	-	-	-	-	-	**$0.380**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.044	$0.138	-	-	-	-	-	-	**$0.182**
Outside Services	$0.073	$0.105	-	-	-	-	-	-	**$0.178**
Business Expense/Overheads	$0.007	$0.005	-	-	-	-	-	-	**$0.012**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.007	$0.001	-	-	-	-	-	-	**$0.008**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.132	$0.248	-	-	-	-	-	-	**$0.380**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.132	$0.248	-	-	-	-	-	-	**$0.380**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.132	$0.248	-	-	-	-	-	-	**$0.380**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.
Technology Capability	Work Management

Enhancements-Security-Capital

Report Pulled: 11/1/2024 **Item ID: 11338**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias Cyber Security Enhancements, Application Currency and Enhancements - Security - O&M, Enhancements – Security – O&M, Enhancements – Security – Capital, Enhancements-Security-Capital

Description This initiative will use Capital funding to make enhancements to existing technology and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements in accordance with accounting rules.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-SECURITY PROGRAM MGI

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance.

Alternatives Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for Security enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$1.270	$0.012	$1.599	$0.776	$0.776	$0.776	$0.776	-	$5.985
O&M	$0.267	-	$0.100	$0.154	$0.154	$0.154	$0.154	-	$0.982
Total Cost of Ownership	$1.537	$0.012	$1.699	$0.930	$0.930	$0.930	$0.930	-	**$6.967**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.617	-	$0.518	$0.287	$0.287	$0.287	$0.287	-	**$2.281**
Outside Services	$0.151	$0.012	$0.274	$0.274	$0.274	$0.274	$0.274	-	**$1.535**
Business Expense/Overheads	$0.131	-	$0.883	$0.345	$0.345	$0.345	$0.345	-	**$2.392**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.026	-	$0.024	$0.024	$0.024	$0.024	$0.024	-	**$0.148**
Licenses, Permits & Fees	$0.612	-	-	-	-	-	-	-	**$0.612**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$1.537	$0.012	$1.699	$0.930	$0.930	$0.930	$0.930	-	**$6.967**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.267	-	$0.100	$0.154	$0.154	$0.154	$0.154	-	**$0.982**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.267	-	$0.100	$0.154	$0.154	$0.154	$0.154	-	**$0.982**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.270	$0.012	$1.599	$0.776	$0.776	$0.776	$0.776	-	**$5.985**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.270	$0.012	$1.599	$0.776	$0.776	$0.776	$0.776	-	**$5.985**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Enhancements-Security-O&M

Report Pulled: 11/1/2024 **Item ID: 8237**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias Cyber Security Enhancements, Application Currency and Enhancements - Security - O&M, Enhancements – Security – O&M, Enhancements-Security-O&M

Description This initiative will use O&M funding to make enhancements to existing technology and to address requests generated by changing business requirements.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-SECURITY PROGRAM MG

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements in Security lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope

Included in the implementation are small changes and functionality improvements to existing IT software application investments for Security in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as cyber security related platforms, cyber security incident response, physical security, security awareness, risk management, privacy and compliance.

Alternatives

Prior to implementing a Security enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for Security enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.632	$0.665	$0.399	$0.319	$0.319	$0.319	$0.319	-	$2.973
Total Cost of Ownership	$0.632	$0.665	$0.399	$0.319	$0.319	$0.319	$0.319	-	**$2.973**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.577	$0.558	$0.356	$0.294	$0.294	$0.294	$0.294	-	**$2.668**
Outside Services	-	$0.079	$0.007	$0.007	$0.007	$0.007	$0.007	-	**$0.114**
Business Expense/Overheads	$0.017	$0.005	$0.036	$0.018	$0.018	$0.018	$0.018	-	**$0.130**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.037	$0.024	-	-	-	-	-	-	**$0.061**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.632	$0.665	$0.399	$0.319	$0.319	$0.319	$0.319	-	**$2.973**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.632	$0.665	$0.399	$0.319	$0.319	$0.319	$0.319	-	**$2.973**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.632	$0.665	$0.399	$0.319	$0.319	$0.319	$0.319	-	**$2.973**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Enhancements-TEOS-Capital

Report Pulled: 11/1/2024 **Item ID: 11328**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Application Currency and Enhancements - TEOS - Capital, Enhancements - TEOS - Capital, Enhancements-TEOS-Capital

Description The TEOS initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-TRANS, OPS SUPPORT AND ENG

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements in the TEOS Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for TEOS.

Scope

The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering, Customer Energy Management, Electric Grid Integration, and Fleet .

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.541	$0.067	-	-	-	-	-	-	$0.608
O&M	$0.042	$0.100	-	-	-	-	-	-	$0.142
Total Cost of Ownership	$0.583	$0.167	-	-	-	-	-	-	**$0.750**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.120	$0.091	-	-	-	-	-	-	**$0.211**
Outside Services	$0.278	$0.066	-	-	-	-	-	-	**$0.344**
Business Expense/Overheads	$0.184	$0.011	-	-	-	-	-	-	**$0.195**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.583	$0.167	-	-	-	-	-	-	**$0.750**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.042	$0.100	-	-	-	-	-	-	**$0.142**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.042	$0.100	-	-	-	-	-	-	**$0.142**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.541	$0.067	-	-	-	-	-	-	**$0.608**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.541	$0.067	-	-	-	-	-	-	**$0.608**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Electric T&D, Gas T&D, Generation
Risk Mitigation	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion.

Enhancements-TEOS-O&M

Report Pulled: 11/1/2024 **Item ID: 11329**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Enhancements - TEOS - O&M, Application Currency and Enhancements - TEOS -O&M, Enhancements - TEOS -O&M, Enhancements - TEOS - O&M, Enhancements-TEOS-O&M

Description The TEOS initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-TRANS, OPS SUPPORT AND ENG

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements in the TEOS Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope

Included in the implementation are small changes and functionality improvements to existing IT software application investments for TEOS. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering, Customer Energy Management, Electric Grid Integration, and Fleet.

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.129	-	-	-	-	-	-	-	$0.129
Total Cost of Ownership	$0.129	-	-	-	-	-	-	-	**$0.129**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.031	-	-	-	-	-	-	-	**$0.031**
Outside Services	$0.089	-	-	-	-	-	-	-	**$0.089**
Business Expense/Overheads	$0.009	-	-	-	-	-	-	-	**$0.009**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.000	-	-	-	-	-	-	-	**$0.000**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.129	-	-	-	-	-	-	-	**$0.129**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.129	-	-	-	-	-	-	-	**$0.129**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.129	-	-	-	-	-	-	-	**$0.129**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Electric T&D, Gas T&D, Generation
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Enterprise Print - Scan Suite

Report Pulled: 11/1/2024 **Item ID: 11651**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Enterprise Print - Scan Suite

Description The projects intent is to upgrade the current Enterprise Print and Capture suite for improved data security and integration for the work from home business partner.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** Unspecified

WORK OBJECTIVES

Problem Statement The company currently maintains a print and capture suite that will have support ending in 2025. Only high-level security patches will be available after this date. The company maintains a fleet of servers that are scheduled to be upgraded. The current print and capture suite is not compatible with the targeted server operating systems. The lack of internal resources requires the company to continue to absorb increased costs to contract administrative personal.

Objectives This project maintains cost savings achieved by eliminating wasteful print jobs and further enables a productive, and flexible workforce for business partners working remotely. This project also ensures that the latest data transmission security requirements of are met by the solution.

Scope The project scope includes: (1) upgrading the current suite to the latest version; (2) consolidating the amount of print servers in the environment; (3) training for company personal to administer the suite; (4) converting all workflows from the current system; (5) implementing remediation for security vulnerability risk;. (6) integrating device management with Enterprise Configuration Management Database (CMDB) for asset tracking and monitoring.

Alternatives Alternatives considered: (1) migrating to cloud services. This alternative was not chosen at this time due to maturity levels found with subscription services. (2) other print-scan products. This alternative was not selected as it would required new print and scanning specific to another print-scan product.. (3) Print-scan products that were less costs. This alternative was not selected, due to fewer capabilities offered than the current product, which would introduction inefficiencies in the current processes. (4) upgrade current product. This alternative was chosen due to lower overall cost of not requiring new hardware, maturity of current product, and providing same level of capabilities required to support current processes.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/1/2024	2/6/2024	3/29/2024	5/31/2024
	In-Service/Go-Live	**Closeout**	
	7/31/2024	10/31/2024	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.680	-	-	-	-	-	-	-	$0.680
O&M	$0.217	$0.004	$0.004	$0.004	$0.004	$0.004	-	-	$0.236
Total Cost of Ownership	$0.897	$0.004	$0.004	$0.004	$0.004	$0.004	-	-	**$0.916**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.244	-	-	-	-	-	-	-	**$0.244**
Outside Services	$0.651	-	-	-	-	-	-	-	**$0.651**
Business Expense/Overheads	$0.002	-	-	-	-	-	-	-	**$0.002**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$0.897	-	-	-	-	-	-	-	**$0.897**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.217	$0.004	$0.004	$0.004	$0.004	$0.004	-	-	**$0.236**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.217	$0.004	$0.004	$0.004	$0.004	$0.004	-	-	**$0.236**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.680	-	-	-	-	-	-	-	**$0.680**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.680	-	-	-	-	-	-	-	**$0.680**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Security maintenance on the current system will become unsupported which will expose the environment to vulnerabilities.
Risk Mitigation	Will allow for mitigation of a current vulnerability with data traffic not encrypted and exposed to any bad agent that would monitor the printer port.

Enterprise Risk Management

Report Pulled: 11/1/2024 **Item ID: 10481**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Enterprise Risk Management

Description The project will implement software to simplify processes pertaining to Enterprise Risk Management, improve efficiency, provide risk identification and repository tools, and provide real-time risk information.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement

The Enterprise Risk Team (ERT) works with Risk Owners (RO) on an annual basis to identify new risks, update existing risks, quantify impacts and likelihoods of these risks, document mitigation plans, identify trends, and formulate risk tolerance metrics. This work is accomplished through an iterative back-and-forth process between ERT and ROs to gain alignment on content. This effort culminates in multiple Risk Map PowerPoint, Microsoft Word and email documents organized by area of risk. These risk maps are then presented to senior management and to the Board of Directors (BoD) on an annual basis. The intensive, time-consuming manual Enterprise Risk Management (ERM) process creates risks of human error that can over or under quantify risks, introduce data anomalies, and create version tracking issues. The existing process results in substantial inefficient use of time by risk analysts and risk owners throughout the Company, limits the breadth of analysis that can be provided, and limits the overall ability of the Company to timely identify, analyze, and communicate risks to our senior leaders, thereby causing potential delays in responding to emerging risks. Because of the lengthy manual process, it is only performed once a year, but must be performed more frequently to proactively manage enterprise risk. Utility industry peers leverage software to more effectively manage enterprise risk management programs.

Objectives

This project creates value for the Company by: (1) providing real-time risk information to interested parties including the risk team, risk owners, senior management, and the Board of Directors (BoD) supporting proactive risk management; (2) creating a centralized repository for risk identification, management, and mitigation plans; (3) eliminating waste by simplifying processes; and (4) improving efficiency of the risk owners and analysts.

Scope

The scope of the project includes: (1) create risk analysis templates and tools for automated reporting; (2) configure automated workflow to perform risk updates; (3) configure dynamic templates that prompt the risk owners based on prior selections; (4) organize risk assessments through an online and searchable data capture (repository); (5) create new reports and executive dashboards; (6) data conversion; and (7) set record retention rules.

Alternatives

Alternatives considered include: (1) Continue use of the current manual processes which result in waste, lack of quality results, and annual review of risks; (2) Build a custom internal enterprise risk solution. This option was not selected as it will not result in an enterprise risk program that leverages best practices that exist in software provided by the leaders in risk management software; and (3) Implement a software solution from a leading enterprise risk solution vendor. While this would introduce new license and ongoing support costs, it is the preferred option because it leverages industry best practices with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation and insights via the reporting of risk information through management dashboards. In addition, it aligns the Company with utility industry peer practices for more effective enterprise risk management.

DATES (phase end)

Initiation 1/1/2026
Project Plan & Scope Definition 4/1/2026
In-Service/Go-Live 12/1/2026
Final Engineering, Planning & Design 6/1/2026
Closeout 1/1/2027
Execution 11/1/2026

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.139	$0.126	$0.126	$0.126	$0.126	$0.019	-	-	$0.664
Total Cost of Ownership	$0.139	$0.126	$0.126	$0.126	$0.126	$0.019	-	-	**$0.664**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.027	$0.023	$0.023	$0.023	$0.023	$0.006	-	-	**$0.125**
Outside Services	$0.058	$0.050	$0.050	$0.050	$0.050	$0.013	-	-	**$0.271**
Business Expense/Overheads	$0.002	$0.002	$0.002	$0.002	$0.002	$0.000	-	-	**$0.009**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.041	$0.041	$0.041	$0.041	$0.041	-	-	-	**$0.204**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.128	$0.116	$0.116	$0.116	$0.116	$0.019	-	-	**$0.609**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.139	$0.126	$0.126	$0.126	$0.126	$0.019	-	-	**$0.664**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.139	$0.126	$0.126	$0.126	$0.126	$0.019	-	-	**$0.664**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Compliance & Risk Management
Avoided Costs	ERM Group can save up to 252 hours annually through efficiencies in: (1) Risk form configuration (24 hours saved); (2) Workflow including email/phone conversations, report creation and Quality control (229 hours saved) These efficiencies would free up time for more value-added activities such as ad hoc analysis, more frequent risk updates to management, emerging risk
Risk Mitigation	Implementing a centralized solution will mitigate risk by better managing risks. One third of the 150 risk tolerance metrics are currently red.
Risk Mitigation	This project would track more than 200 corporate risk tolerances from the Impact group within the Business Planning System (BPS). The Corporate Risk group tracks all of these risks and the number of risks is expected to grow over time.

Enterprise Service Bus Application 2020-2021 Upgrade

Report Pulled: 11/1/2024 **Item ID: 6734**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ESB BW6 Upgrade,Enterprise Service Bus Application Upgrade, Enterprise Service Bus Application 2020-2021 Upgrade

Description This project will upgrade and migrate the Business Works developer application to the next version.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-PROD TRANSF, ARCH & QUAL

WORK OBJECTIVES

Problem Statement

Newer Enterprise Service Bus (ESB) software versions offer improved integration with cloud-based services and applications. As the Company increasingly migrates to cloud-based Infrastructure, Platform- and Software-as-a-Service solutions, it is critical that this vital data tool or pathway, be more scalable, secure, and capable of working in a cloud-based environment. In addition, the messaging and event modules within the ESB are currently outside of their standard support windows. While it is possible to continue to get extended support by paying an estimated premium of $40,000, this is just temporary coverage and serves only to delay the need for an upgrade—not a prudent use of resources.

Objectives

The value this project provides the Company includes: (1) accelerated productivity; (2) continuous delivery and integration; (3) an open ecosystem for improved operational visibility; (4) real-time integration with web, mobile apps, and application programming interfaces; and (5) improved administrative and operational efficiencies.

Scope

The project scope includes: (1) implementing new versions of all applications that are part of the Tibco ESB software suite – BusinessWorks, Enterprise Messaging Service, BusinessEvents, API Exchange, and Hawk; and (2) a server refresh. The new products will be implemented on the latest version of the SUSE Enterprise Edition operating system.

Alternatives

Alternatives considered included: (1) Absorb the annual $40,000 maintenance cost and lose supportability. Given the critical nature of this application, it is not recommended to lose mainstream support for any of the applications involved. Any sustained ESB product deficiency would impact many areas of the Company, such as billing, revenue collection, and remote meters. The current implementation of the ESB platform was built with 5 years of growth in mind. This alternative was not chosen for these reasons, and the additional expense. (2) Replace the platform by moving it to cloud. Migrating the ESB to the cloud would be too early in the Company's strategy for cloud adoption, which may cause issues with operational stability and incur additional expenditure. A cloud migration would also take longer to plan, which would put the Company at risk of falling outside of the the current vendor support window for the product's current version. (3) Upgrade the existing application. This option was selected because it best suits customer and Company needs for the near future by restoring vendor support for hot fixes and patches, and enables product scalability to the measure required of the business.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/1/2021	2/28/2021	3/31/2021	4/1/2021
	In-Service/Go-Live	**Closeout**	
	4/1/2022	5/1/2022	

FUNDING SUMMARY

	2020	2021	2022	2023	2024	2025	2026	2027 +	Total
Cap+COR	-	$1.736	$2.143	$1.543	$0.000	-	-	-	$5.423
O&M	$0.069	$0.245	$0.322	$1.044	-	-	-	-	$1.679
Total Cost of Ownership	$0.069	$1.981	$2.465	$2.587	$0.000	-	-	-	**$7.102**

	2020	2021	2022	2023	2024	2025	2026	2027 +	Total
Labor	$0.021	$0.249	$0.510	$0.753	$0.000	-	-	-	**$1.534**
Outside Services	$0.043	$1.471	$1.460	$1.180	-	-	-	-	**$4.154**
Business Expense/Overheads	$0.005	$0.261	$0.433	$0.486	$0.000	-	-	-	**$1.185**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.033	$0.167	-	-	-	-	**$0.200**
Licenses, Permits & Fees	-	-	$0.029	$0.001	-	-	-	-	**$0.030**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.069	$1.981	$2.465	$2.587	$0.000	-	-	-	**$7.102**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2020	2021	2022	2023	2024	2025	2026	2027 +	Total
O&M	Reduction	-	$(0.030)	$(0.030)	-	-	-	-	-	**$(0.060)**
	Initial	$0.069	$0.245	$0.322	$1.044	-	-	-	-	**$1.679**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.069	$0.215	$0.292	$1.044	-	-	-	-	**$1.619**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$1.736	$2.143	$1.543	$0.000	-	-	-	**$5.423**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$1.736	$2.143	$1.543	$0.000	-	-	-	**$5.423**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.992

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Consumers Energy will lose support on critical ESB software components that support OpenWay Collection Engine, SAP, ITRON, DIV, DRMS, MDM, IWP, PayGo, Grid Director, Field Service Solution, and Digital Customer Experience. Rebuilding the ESB Platform and ensuring the current production integrations will not be impacted as well as meeting or exceeding current service levels is critical.
Capacity	The current implementation of the ESB platform was built with 5 years of growth in mind. Upgrading the ESB on a regularly scheduled cadence will allow Consumers to grow the the application around the business' needs.

Enterprise Service Bus Application 2024-2025 Upgrade

Report Pulled: 11/1/2024 **Item ID: 11727**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ESB BW6 Upgrade,Enterprise Service Bus Application Upgrade, Enterprise Service Bus Application 2023-2024 Upgrade, Enterprise Service Bus Application 2024-2025 Upgrade

Description This project will upgrade and migrate the Business Works developer application to the next version.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement
Newer ESB software versions offer improved integration with Rest/API services and applications. It is critical that this vital data tool or pathway, be more scalable, secure, and capable of integrating to a service-based environment. In addition, the messaging and event modules within the ESB are currently outside of their standard support windows. While it is possible to continue to get extended support by paying an estimated premium of approximately $80,000 annually, this is just temporary coverage and serves only to delay the need for an upgrade.

Objectives
The value this project provides the Company includes: (1) cost avoidance to avoid extensive payments for extend support purposes; (2) avoid technical obsolescence; (3) operational resiliency; and (4) improved administrative and operational efficiencies.

Scope
The project scope includes implementing current version of all applications that are part of the ESB application, database version, and required database drivers.

Alternatives
Alternatives considered included: (1) Accept the annual $80,000 extended maintenance cost. Given the critical nature of this application, it is not recommended to lose mainstream support for any of the applications involved. Any sustained ESB product deficiency would impact many areas of the Company, such as billing, revenue collection, and remote meter management. The current implementation of the ESB platform was built with 5 years of growth in mind. This alternative was not chosen due to risk to Company operations , and the additional expense. (2) Replace the on-premise upgrade plan to implement a cloud-based solution. A cloud migration would also take longer to complete, which would put the Company at risk of falling outside of the current vendor support window for the products current version. (3) Upgrade the existing application. This option was selected because it best meets the Company needs for the near future by restoring vendor support for fixes and patches, and enables product scalability to the measure required of business capabilities.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
9/4/2024	10/7/2024	11/15/2024	1/8/2025
	In-Service/Go-Live	**Closeout**	
	10/18/2025	11/21/2025	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.007	$0.777	-	-	-	-	-	-	$0.784
Total Cost of Ownership	$0.007	$0.777	-	-	-	-	-	-	**$0.784**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.007	$0.726	-	-	-	-	-	-	**$0.733**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	-	$0.051	-	-	-	-	-	-	**$0.051**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.007	$0.777	-	-	-	-	-	-	**$0.784**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.007	$0.777	-	-	-	-	-	-	**$0.784**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.007	$0.777	-	-	-	-	-	-	**$0.784**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Consumers Energy will lose support on critical ESB software components that support OpenWay Collection Engine, SAP, ITRON, DIV, DRMS, MDM, IWP, PayGo, ADMS, Field Service Solution, and Digital Customer Experience. Rebuilding the ESB Platform and ensuring the current production integrations will not be impacted as well as meeting or exceeding current service levels is critical.
Avoided Costs	Consumers Energy will need to purchase an extended support contract with the vendor to maintain support of the older version. Going too long without upgrading puts Consumers at risk of losing any level of support from the vendor. Current estimate is $80,000 of extended support
Capacity	The current implementation of the ESB platform was built with 5 years of growth in mind. Upgrading the ESB on a regularly scheduled cadence will allow Consumers to grow the the application around the business' needs.

Expense Reporting Improvements

Report Pulled: 11/1/2024 **Item ID: 11759**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Expense Reporting Improvements

Description The Expense Reporting Improvements project will increase productivity when creating expense reports; leverage workflows for expense processing and exceptions; improve adherence to company policies; provide insights through improved reporting; and minimize human intervention and struggle throughout the expense process.

Portfolio Corporate Services > Financial Services > Controller > General Accounting > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement Multiple problems exist with our current expense reporting system in the areas of usability, employee engagement, inefficiencies, compliance, and audit exceptions. Submitting expense reports is not intuitive, leading to errors and the need for manual intervention. In addition, employees have to manually scan and attach receipts. All these problems impact employees leading to poor employee engagement scores in regards to simple processes, productivity, and transparency leading to increased costs, inefficiencies, exceptions to policies, and compliance issues. An average of 13% of all expense reports have compliance errors, based on a sample audit of executive assistant submitted expense reports.

Objectives This project provides value for the Company by: (1) improving expense policy compliance and reducing exceptions, with a target measure of 0 compliance errors; and (2) offering a more user-friendly experience leading to improved employee engagement. Completion of these objectives would enable each employee to save 20 minutes creating an expense report for each of the 50,175 expense reports created in 2021, the Company would have avoided approximately $1.5MM of costs, based on a $90/hr. average rate.

Scope The project scope includes implementing a new software tool that: (1) provides upfront validation and controls to improve policy compliance; (2) provides electronic document retention for receipts; and (3) integrates corporate credit card data into expense reports.

Alternatives Three alternatives were considered for the project: (1) continue using the current solution; (2) choose a cloud-based solution with the expense reporting component; and (3) develop a custom front-end. The first alternative would result in waste due to the system not being user-friendly; and does not provide mobile options. The second alternative would introduce new licensing and ongoing maintenance costs; would require periodic upgrades and testing; and would require the SAP Enterprise Portal to be upgraded to integrate with the booking tool. The third alternative and selected option would result in improved user experience and employee engagement as well as mobile capabilities around expense entry.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
6/1/2026	7/1/2026	11/1/2026	5/1/2027
	In-Service/Go-Live	**Closeout**	
	5/2/2027	6/30/2027	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	$0.589	$0.723	-	-	-	$1.312
O&M	-	-	-	$0.140	$0.076	-	-	-	$0.217
Total Cost of Ownership	-	-	-	$0.730	$0.799	-	-	-	**$1.529**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	-	-	-	$0.280	$0.310	-	-	-	**$0.590**
Outside Services	-	-	-	$0.290	$0.300	-	-	-	**$0.590**
Business Expense/Overheads	-	-	-	$0.160	$0.189	-	-	-	**$0.349**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	-	-	$0.730	$0.799	-	-	-	**$1.529**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	$0.140	$0.076	-	-	-	**$0.217**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	$0.140	$0.076	-	-	-	**$0.217**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	$0.589	$0.723	-	-	-	**$1.312**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	$0.589	$0.723	-	-	-	**$1.312**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	An average of 13% of all expense reports have compliance errors, based on a sample audit of 2021. The target measure with the completion of this project is 0% compliance errors.
Avoided Costs	If each employee saved 20 minutes creating an expense report for each of the 50,175 expense reports created in 2021, that equates to ~16,725 hours saved x $100/hr average rate = $1.67M of avoided costs due to increased efficiencies.

Field Contractor Work Management Technology Enablemer Report Pulled: 11/1/2024 Item ID: 6740

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias FSS Release 4 - Contractor Enablement

Description The project provides the ability to electronically manage contractor work and increases accuracy and timeliness of information processing for field work deliverables. This project additionally creates new opportunities to measure and optimize field work processes supporting customer on-time delivery goals.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement Contractor field employees use manual, paper-based processes and generic communication technologies (phone, radio, email, collaboration sites) to perform work for the Company. Due to the non-electronic format, inaccuracy, and delay of information processing there are negative impacts to the availability and accuracy of work status. This limits the opportunity to measure and optimize field work processes that support customer on-time delivery and other goals.

Objectives The project will add value by: (1) improving on-time delivery of customer work by providing electronic work order information to contractors; (2) improving customer satisfaction through efficiency in scheduling work and reporting on the progress electronically; (3) increasing safety by tracking work and contractor status providing visibility into the last known location of the contractor; (4) improving material management; (5) making it easier to move emergent work to contractors to balance workloads and meet customer commitments; and (6) enabling real time updates to work order information, increasing data accuracy and reducing invoice reconciliation time.

Scope The project scope includes: (1) identifying requirements for a Bring Your Own Device (BYOD) field contractor work management technology solution and process; (2) developing, configuring, and testing interfaces, hardware, and software for the solution; (3) implementing the solution and process for the following work groups: Electric High-Voltage Distribution (HVD), Electric Low-Voltage Distribution (LVD), Mutual Assistance, Forestry, Gas Distribution, Gas Code Compliance, and Substation Operations Construction/Metro; (4) updating the following vendor contract types to support BYOD field contractor work management: zone, specific bid, ancillary, electric storm, and mutual assistance; and (5) training field contractors on the new technology and processes.

Alternatives The alternatives considered included: (1) Continue with the current paper-based process. This alternative was not selected because this approach does not allow for the timely, data-driven work management metrics required to improve service to customers. (2) Use the current Company mobile application. This alternative was not selected because the solution is not expected to receive long term investments by the vendor and the mobile application would require more upfront investment than the proposed option. (3) Use off-platform options such as ServiceBench. This alternative was not selected because contractors would not be able to leverage the benefits and integrations with the existing platform and it would require additional new integrations. (4) Provide Company-funded field devices to contractors. This alternative was not selected because the investment in hardware, management of on-boarding and off-boarding of devices to contractors, and training and change management is cost-prohibitive and introduces a risk of the loss of control of information security and corporate assets. Leveraging the existing field work management solution was chosen because it uses existing well-developed functionality while leveraging cloud-based, BYOD capabilities to move short-term and long-term contractors from paper processes to the established, standard work management system.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/31/2022	3/31/2022	9/30/2022	7/31/2023
	In-Service/Go-Live	**Closeout**	
	9/16/2024	10/1/2024	

FUNDING SUMMARY

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Cap+COR	-	$0.027	$0.343	$1.797	-	-	-	-	$2.168
O&M	$0.243	$0.218	$0.023	$0.141	$0.508	$0.508	$0.508	$0.508	$2.656
Total Cost of Ownership	$0.243	$0.245	$0.367	$1.938	$0.508	$0.508	$0.508	$0.508	**$4.824**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.229	$0.082	$0.098	$0.654	-	-	-	-	**$1.063**
Outside Services	-	$0.144	$0.212	$0.812	-	-	-	-	**$1.168**
Business Expense/Overheads	$0.014	$0.019	$0.054	$0.106	-	-	-	-	**$0.193**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.003	$0.366	-	-	-	-	**$0.369**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.243	$0.245	$0.367	$1.938	-	-	-	-	**$2.793**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2021	2022	2023	2024	2025	2026	2027	2028 +	Total
O&M	Reduction	-	-	$(0.144)	$(0.144)	$(0.144)	$(0.144)	$(0.144)	-	**$(0.719)**
	Initial	$0.243	$0.218	$0.023	$0.141	$0.508	$0.508	$0.508	$0.508	**$2.656**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.243	$0.218	$(0.120)	$(0.003)	$0.364	$0.364	$0.364	$0.508	**$1.937**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.027	$0.343	$1.797	-	-	-	-	**$2.168**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.027	$0.343	$1.797	-	-	-	-	**$2.168**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.865

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	"CE Way" Maturity - The project enables data to be more accessible electronically so that it can be visualized, access to data provides increased visibility to problem solving, and Service Suite forms allow for increased standardization.
Intangibles	Customer On-time Deliver (COTD) - Provides real-time updates for work order progression and completion, and provides increased efficiency in dispatching work to contractors.
Intangibles	Electric Reliability - Improves efficiency in dispatching of emergent work to contractors.
Avoided Costs	Engineering/System Owner Efficiencies: Estimated 1 hour per week @ 50 weeks for 10 system owners = 500 hours annually *$50/hr = $25,000 Annual $ Saved (Max). Annual $ Avoided (Min - 75% of Max) = $18,750 * 29.8% (O&M) = $5,588 annual avoided costs
Avoided Costs	Field Leader & Back End Efficiencies: 1 Hour per week for each long cycle field leaders/back office personnel - "200 people*50weeks= 20K hours * $50/hr = $500K." Annual $ Avoided (Min - 75% of Max) = $375K. $375K * 29.8% (O&M) = $111,750 annual avoided costs - ELECTRIC SPLIT
Avoided Costs	Field Leader & Back End Efficiencies: 1 Hour per week for each long cycle field leaders/back office personnel - "200 people*50weeks= 20K hours * $50/hr = $500K." Annual $ Avoided (Min - 75% of Max) = $375K. $375K * 29.8% (O&M) = $111,750 annual avoided costs - GAS SPLIT
Avoided Costs	Increase Back Office Productivity for Contractor Admins: 1 employee for 6 hours a week and 50 weeks per year. Total hours reclaimed annually = 300 hours * $50/hr = $15,000. Annual $ Avoided (Min - 75% of $15,000) = $11,250 * 29.8% (O&M) = $3,353.
Avoided Costs	Increased Productivity for Contractors: 150 hours reclaimed per month * 12 Months a year = 1,800 total hours reclaimed annually * rate of $71.70/hr = $129,060 total. Annual $ Avoided (Min - 75% of $139,060) = $96,795 * 29.8 (O&M)= $28,845
Technology Capability	Work Management

Field Mapping and Graphics

Report Pulled: 11/1/2024 **Item ID: 8771**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias ArcPad Retirement, Field Mapping and Graphics

Description This project will implement a solution for the mobile field mapping and data collection that can search and view facility map data, view work order designs, and create work order as-built construction drawings in the field. This software technology increases process efficiency by consolidating field graphics functionality, reducing IT complexity and testing, and increasing adoption in the field through ease of use. In addition, it allows the Company to move to a supported application platform and retire the unsupported ArcPad solution.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement The current mapping and graphics application was implemented in 2002 and is no longer sold or supported in any capacity, and the customizations developed for the application cannot be changed. Due to the improved accuracy of the CE landbase (streets, political boundaries, etc.), the outdated electric maps that are referencing that data causes the map to be unreadable which causes a safety issue. Additionally, field employees have considerable challenges when attempting to use the software due to slowness, an aged interface, and dated processes.

Objectives The project will add value by: (1) providing more accurate geospatial data, including facility map data, pre-construction designs, and as-built construction drawings; (2) consolidating daily tasks into a more simplified process; (3) eliminating the process waste from duplicating asset data in two systems; (4) enabling the adoption of the Geographic Information System (GIS) standard; and (5) making mapping and graphics data available on field devices.

Scope The project scope includes: (1) installing a new mobile field mapping and graphics application; (2) creating the ability to search and view the facility map data in GIS format along with the ability to search by address; (3) viewing pre-construction work order designs in a new GIS format; and (4) creating as-built construction drawings in GIS format for assigned work orders.

Alternatives Four alternatives were evaluated and three were determined non-viable for the project: (1) Continue maintaining the current ArcPad application. This option was not selected because the Company is no longer able to make changes to the ArcPad application to mitigate issues if the application has critical defects. A total failure of the application could revert field crews back to paper-based facility maps, risking safety using static, outdated data; or require the creation of as-built construction drawings on paper documents. (2) Use the Adobe or Snagit applications for creating as-built construction drawings. This option was not selected because field users would have to use one solution for viewing facility maps and use rudimentary drawing tools like Adobe or Snagit for creating as-built construction drawings. This option was also not selected because it introduces additional costs due to the complexity and customization needed to integrate the applications. (3) Build a custom Mapping and Graphics solution. This option was not selected as existing industry solutions are available at a much lower cost with much less risk. (4) Implementing the new field mapping and graphics software was selected as this option will consolidate field graphics functionality into an efficient process and provide a current, supported solution.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/31/2021	4/30/2021	8/31/2021	6/1/2023
	In-Service/Go-Live	**Closeout**	
	6/30/2023	6/30/2023	

FUNDING SUMMARY

	2020	2021	2022	2023	2024	2025	2026	2027 +	Total
Cap+COR	-	$0.757	$1.772	$1.103	$0.768	-	-	-	$4.401
O&M	-	$0.015	$0.001	$0.040	$0.016	-	-	-	$0.071
Total Cost of Ownership	-	$0.771	$1.773	$1.143	$0.784	-	-	-	**$4.471**

	2020	2021	2022	2023	2024	2025	2026	2027 +	Total
Labor	-	$0.438	$0.299	$0.312	$0.463	-	-	-	**$1.513**
Outside Services	-	$0.144	$1.046	$0.372	$0.273	-	-	-	**$1.834**
Business Expense/Overheads	-	$0.189	$0.427	$0.458	$0.048	-	-	-	**$1.122**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	$0.001	$0.001	-	-	-	-	**$0.002**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$0.771	$1.773	$1.143	$0.784	-	-	-	**$4.471**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2020	2021	2022	2023	2024	2025	2026	2027 +	Total
O&M	Reduction	-	-	$(0.064)	$(0.064)	$(0.064)	$(0.064)	$(0.064)	-	**$(0.319)**
	Initial	-	$0.015	$0.001	$0.040	$0.016	-	-	-	**$0.071**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.015	$(0.063)	$(0.024)	$(0.048)	$(0.064)	$(0.064)	-	**$(0.248)**
Cap+COR	Reduction	-	-	$(0.149)	$(0.149)	$(0.149)	$(0.149)	$(0.149)	-	**$(0.743)**
	Initial	-	$0.757	$1.772	$1.103	$0.768	-	-	-	**$4.401**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.757	$1.624	$0.955	$0.619	$(0.149)	$(0.149)	-	**$3.657**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.796

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	Medium	Consumers Energy employees are experiencing decline in application performance due to age, which produces the risk of application failure.

OTHER VALUE

Type	Description
Intangibles	Currently, there is a decrease in morale and increase in stress when redlines aren't processed in a timely way or get held up with technology problems. The current process is go back to the crew to inquire if the redline was completed. When this is a system issue, it causes frustration because then the field has to re-do work in the field. Doing this project will improve morale and improve the relationship between management and the Union by reducing administrative pain, human struggle and disagreements, and wasted time repeating work.
Intangibles	Make OVH (overhead) data available to the field device. The current OVH CAD files have not been maintained in over five years.
Intangibles	Make URD-(Underground Maps) assets readable on field device. This is currently a safety issue.
Intangibles	Reduced errors/defects and postings improves Safety by reducing lag time in data updates and if there's a revisit to the Asset. The correct information is on file.
Risk Mitigation	The application is at risk of failure. It is no longer supported, cannot be upgraded or changed in any manner. Retiring the application and moving to a new application must occur in order for the risk to be removed.
Technology Capability	Work Management

Field Network Director

Report Pulled: 11/1/2024 **Item ID: 12453**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Field Network Director

Description Design, develop, test and implement Cisco's Field Network Director (FND). FND is a network management solution for Field Area Networks (FAN). The solution is necessary for the management of the modems that have been selected as the new Company standard for modems, as the previous standard modem is no longer being manufactured.

Portfolio IT Services > Applications > Electric Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-TRANS, OPS SUPPORT AND ENG

WORK OBJECTIVES

Problem Statement The modems used for Electric and Gas field device deployments have been discontinued by the manufacturer and the existing inventory will be exhausted by September 2021. After an extensive analysis of 6 modems, a modem was selected as the new standard, replacing the discontinued device. Configuring and managing modems manually is an ongoing, time consuming and labor intensive effort with tasks that include; modem configuration, firmware updates and modem status analytics, exasperated by the need to apply cyber security requirements. With no centralized software to manage the modems: 1) every modem will need to be manually configured, resulting in deployment delays and/or head-count increases; 2) lack of centralized over-the-air device management will introduce increased cyber security risks. Modem management software is required in order to effectively introduce, monitor and manage the new modem type.

Objectives Support modem configuration, operations and management with a solution that provides capability to manage the new field based communications devices from a centralized platform.

Scope Purchase, install, configure and integrate Citrix's Field Network Manager (FNM) software.

Alternatives Alternative 1, Stock and install selected modems without implementation of the FND. This alternative was not selected as manual management of modems will require; 1) Additional FTEs (+1 in 2022, +1 in 2024); 2) cyber security vulnerabilities will not be mitigated: 3) quality will be degraded with many manual steps. Alternative 2, evaluate other hardware vendors was not selected because of the immediate need to replenish modem stock as the previous modem is no longer manufactured and current stock is expected to be depleted in September 2021, Alternative 3, to utilize Citrix Field Network Manager (FNM) Software, which is the most cost effective approach to support existing inventory of modems; support the new standard modems; automation in configuration and management upgrades in firmware, modem status analytics, and cyber security requirements through a centralized platform.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
7/15/2021	9/30/2021	10/29/2021	4/29/2022
	In-Service/Go-Live	**Closeout**	
	5/13/2022	6/15/2022	

FUNDING SUMMARY

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Cap+COR	$0.225	$0.391	$0.429	$0.027	-	-	-	-	$1.072
O&M	$0.014	$0.110	$0.058	-	-	-	-	-	$0.183
Total Cost of Ownership	$0.239	$0.500	$0.488	$0.027	-	-	-	-	**$1.254**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.025	$0.101	$0.088	-	-	-	-	-	**$0.214**
Outside Services	$0.043	$0.244	$0.318	$0.089	-	-	-	-	**$0.694**
Business Expense/Overheads	$0.003	$0.066	$0.082	$0.027	-	-	-	-	**$0.177**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.133	$0.089	-	$(0.089)	-	-	-	-	**$0.133**
Licenses, Permits & Fees	$0.036	-	-	-	-	-	-	-	**$0.036**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.239	$0.500	$0.488	$0.027	-	-	-	-	**$1.254**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2021	2022	2023	2024	2025	2026	2027	2028 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.014	$0.110	$0.058	-	-	-	-	-	**$0.183**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.014	$0.110	$0.058	-	-	-	-	-	**$0.183**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.225	$0.391	$0.429	$0.027	-	-	-	-	**$1.072**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.225	$0.391	$0.429	$0.027	-	-	-	-	**$1.072**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Information Theft	High	Medium	Solution will provide enhancements to cyber security through; 1)digital certificates to authenticate devices; 2) device staging/quarantine for newly discovered devices; 3)automated encrypted tunnel creation based on device grouping/tagging and; 4)unique private key certificates per device/tunnel

OTHER VALUE

Type	Description
Intangibles	Centralized and secure, over-the-air device management for both device configuration, firmware and security patches.
Technology Capability	Improved device health monitoring and reporting capabilities will be leveraged by other initiatives.
Risk Mitigation	New geo-location capabilities including geo-fencing used to improve field device security.
Intangibles	Solution will provide enhanced troubleshooting capabilities with edge device awareness.
Avoided Costs	Without this software, the OT team would need to manually configure and support (patches, firmware upgrades...)all new modems deployed in the field. This would result in deployment delays and/or head-count increases; 2022 - 1 FTE- $150k + 2023 $150k 1 FTE.

Flexible and Advanced Payment Options

Report Pulled: 11/1/2024 **Item ID: 9030**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Flexible/Advanced Payment Options, Flexible and Advanced Payment Options

Description The project will address customer concerns regarding existing payment plan options. The effort will create payment plans for customers to increase successful payments and accommodate specific needs of customers requiring assistance paying their energy bill.

Portfolio Customer Services > Revenue Management > Payment Channels > Digital Payments > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement Currently, the Company payment arrangement offerings are insufficient or lack flexibility to support the needs of customers. On average, Inability-to-Pay Customers account for 874,000 calls into contact centers to resolve payment plan-related concerns. Existing payment plan options have a 5% success rate. In order to increase customer satisfaction, reduce calls to contact centers, and reduce payment plan defaults the Company needs to offer payment-challenged customers easier and more flexible payment options.

Objectives The project creates value to both the Company and its customers through: (1) improved customer experience by ensuring customers can set up payment programs within the channel of their choice (2) reduced defection for repeat callers by enabling customers to be successful in payment programs, (3) reduced active arrears by removing unnecessary risk and offering options based on customers' history, (4) reduced volume of customers entering dunning with successful payment plans, and (5) reduced complaints regarding payment options.

Scope The scope of this project includes: (1) identifying changes for new and existing payment plans to increase successful customer payments, (2) updating SAP with eligibility rules for payment plans, (3) updating the customer self-service portal and IVR to align with available payment options and self-service capability, (4) reviewing customer feedback to determine the right payment plans to support their needs, (5) implementing an installment plan guide on the digital platform enabling customers to self-serve and select the best plan for them, and (6) improving input screens for Customer Service Representatives (CSR) surrounding payment plans.

Alternatives The alternatives considered include: (1) Enable only CSR resources to set up customized payment plans. This was not selected as the customer is unable to self-serve, preventing call reduction in our contact centers. (2) Utilize a PrePay program for all customers needing payment assistance. This was not chosen as the pilot completed showed limited success as a small portion of customers chose to stay on the program. (3) Implement changes to Payment Assistance plans. This was selected as it provides the customer with multiple options to pay their bill while supporting the Company's cost savings goals.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
10/1/2022	11/28/2022	4/14/2023	4/16/2023
	In-Service/Go-Live	**Closeout**	
	4/17/2023	5/1/2023	

FUNDING SUMMARY

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Cap+COR	-	$0.717	$0.625	-	-	-	-	-	$1.343
O&M	$0.180	$0.135	$0.054	-	-	-	-	-	$0.369
Total Cost of Ownership	$0.180	$0.852	$0.679	-	-	-	-	-	**$1.711**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.171	-	$0.056	-	-	-	-	-	**$0.226**
Outside Services	-	$0.741	$0.558	-	-	-	-	-	**$1.299**
Business Expense/Overheads	$0.009	$0.111	$0.065	-	-	-	-	-	**$0.185**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.180	$0.852	$0.679	-	-	-	-	-	**$1.711**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2021	2022	2023	2024	2025	2026	2027	2028 +	Total
O&M	Reduction	-	-	$(0.080)	-	-	-	-	-	**$(0.080)**
	Initial	$0.180	$0.135	$0.054	-	-	-	-	-	**$0.369**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.180	$0.135	$(0.027)	-	-	-	-	-	**$0.288**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.717	$0.625	-	-	-	-	-	**$1.343**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.717	$0.625	-	-	-	-	-	**$1.343**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.959

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Customer Mgmt
Intangibles	Reduction in active arrears with increased success of customer payments. Decreased payment plan defaults would reduce the customers in dunning and reduce arrears.

Forward Web Proxy Services

Report Pulled: 11/1/2024 **Item ID: 13974**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias , Forward Web Proxy Services

Description This project will replace the current web proxy service platform with a new platform. A web proxy service is a type of proxy server that sits between a client and the internet. It acts as an intermediary that evaluates, modifies, and forwards the client's requests to the destination web server. This service offers many benefits for the Company such as advanced filtering. Advanced filtering in a forward web proxy service can filter out unwanted or harmful content from the internet, such as malware and phishing. This can protect the client's device and network from cyberattacks and improve their browsing experience. Without advanced filtering, the Company's cyber assets are at risk of attacks such as ransomware.

Portfolio Corporate Services > Security Services > Cyber Security & Shared Services > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STAN

WORK OBJECTIVES

Problem Statement The Company currently leverages an existing vendor platform for web proxy services that has been in existence since 2021. Since the implementation of the platform, is has caused ongoing operational issues related to web filtering and connectivity. When there is a degradation of service, company employees and contractors are unable to access internet or cloud-based resources. As the company continues its cloud and SAAS journey, it is imperative to provide consistent access and communication, while still protecting the company from cyber threats.

Objectives This project creates value for the Company by (1) increasing service reliability for employees and contractors to internet and cloud-based resources; (2) utilize technology to enable the Company to handle all types of different workloads from varying geographic locations and is highly available; (3) using a mature and scalable web proxy service provider; and (4) providing Zero Trust by continuously verifying every connection request.

Scope The project scope includes: (1) replacing the current web proxy services solution and implementing a new system; (2) replacing physical web proxy hardware; and (3) potentially changing SAAS cloud vendors

Alternatives The Security team did extensive research on alternative web proxy services solutions. Alternatives considered include: (1) continue to use and maintain the current web proxy services platform. This alternative was not chosen due to the consistent operational issues with the platform that make it unreliable. The result of an unreliable system means that employees and contractors are unable to access business critical services such as email, Teams, ServiceNow, SharePoint Online; (2) Route all internet traffic through the Company's corporate data center. This alternative wasn't chosen because the capabilities of firewalls aren't as effective in stopping sophisticated cyber-attacks as using a web proxy service; (3) replace current system with modern vendor platform for web proxy services. The option that was chosen is to replace the current solution with a new system. This option was chosen because it offers additional features such as browser isolation (the ability to contain web pages so that the web page can't affect the client workstation) and sandboxing (a way to safely execute malicious applications without impacting the Company's network). As part of the evaluation the Company reassessed based on outside advisors and industry trend analysis, focusing on the ability to execute and the vendor's company strategy.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/15/2026	2/15/2026	4/15/2026	6/1/2026
	In-Service/Go-Live	**Closeout**	
	11/15/2026	1/30/2027	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	$4.482	-	-	-	-	-	-	-	$4.482
O&M	$0.484	$0.139	$0.130	$0.130	-	-	-	-	$0.883
Total Cost of Ownership	$4.965	$0.139	$0.130	$0.130	-	-	-	-	**$5.364**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.059	$0.139	$0.130	$0.130	-	-	-	-	**$0.457**
Outside Services	$0.192	-	-	-	-	-	-	-	**$0.192**
Business Expense/Overheads	$0.507	$0.001	-	-	-	-	-	-	**$0.507**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$4.208	-	-	-	-	-	-	-	**$4.208**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$4.965	$0.139	$0.130	$0.130	-	-	-	-	**$5.364**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.484	$0.139	$0.130	$0.130	-	-	-	-	**$0.883**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.484	$0.139	$0.130	$0.130	-	-	-	-	**$0.883**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$4.482	-	-	-	-	-	-	-	**$4.482**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$4.482	-	-	-	-	-	-	-	**$4.482**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Information Theft	High	High	Avoid the cost and disruption of data loss from users, SaaS apps, and public cloud infrastructure due to accidental exposure, theft, or double extortion ransomware.
Information Theft	High	High	Stop advanced cyberthreats with built-in protections against botnets, command-and-control traffic, risky peer-to-peer sharing, malicious active content, cross-site scripting, fraud sites
Information Theft	High	High	The ability to know when patient zero phishing attacks are attempting to infiltrate the Company with advanced AI-based inline detection
Information Theft	High	High	The application will give the ability to know when patient zero phishing attacks are attempting to infiltrate the Company with advanced AI-based inline detection
Information Theft	High	High	The new solution will have the ability to filter risky and malicious domains and stop the use of DNS tunneling to transfer of malicious payloads and sensitive data

OTHER VALUE

Type	Description
Technology Capability	Browser isolation (the ability to contain web pages so that the web page can't effect the client workstation)
Technology Capability	Empower employees and contractors to securely access web applications and cloud services from anywhere, on any device—and ensure a great digital experience where applicable in the Company.
Technology Capability	Increase service reliability for employees and contractors to internet and cloud-based resources for employees and contractors
Technology Capability	Provide Zero Trust by continuously verifying every connection request
Technology Capability	Sandboxing (a way to safely execute malicious applications without impacting the Company's network)
Technology Capability	The new solution will provide more reliable protection against unwanted or harmful content from the internet, such as malware and phishing. This can protect the client's device and network from cyberattacks and improve their browsing experience. Without advanced filtering, the Company's cyber assets are at risk of being attacked by ransomware.

Gas Compression Digital Work Management

Report Pulled: 11/1/2024 **Item ID: 12677**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias ER Mobility, Generation Operations Work Management Mobility, Generation Operations Digital Work Management, Generation Operations And Compression Digital Work Management, Generation Compression Digital Work Management, Compression Digital Work Management, Generation Compression Digital Work Management, Gas Compression

Description The project provides work management software and digital forms for Gas Compression facilities.

Portfolio Gas Delivery Systems > Gas Operations > IT Projects > IT Projects > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-GAS

WORK OBJECTIVES

Problem Statement The current work management process for Gas Compression is cumbersome, largely paper based, and is made up of multiple disconnected systems. This leads to poor visibility, process inefficiency and waste, re-work, regulatory risk, and human error.

Objectives This project provides value to the Company through: (1) increased productivity by direct data entry in the field; (2) improved quality through increased accuracy of updates completed at the time and place of the work; (3) elimination of the need to enter data into multiple disconnected systems, and (4) improved safety through access to real-time information used at work sites rather than printed procedures.

Scope The scope of the project includes: (1) Merging the existing work management tools into a single work management solution, (2) purchasing licenses to add Gas Compression users to the company's existing mobile work management software, and (3) configuring changes in SAP and the mobile work management software to replace the paper-dependent work management process with the ability to access and update maintenance, operations, and safety information for Gas Compression.

Alternatives Alternatives considered include: (1) Utilize an SAP work management mobile solution. An SAP work management solution is not preferred since it is a new solution and requires additional project and support cost. (2) Continue the manual paper-based process. Continuing the manual paper-based process was not chosen because of process waste, re-work, and human error. (3) Customize the existing electronic Shift Operations Management System (eSOMS) mobile application to add work management functions. A custom eSOMS mobile application was not chosen because it would require additional project cost and an ongoing support budget for a custom solution that the eSOMS product was not intended to support. (4) Adopt a cloud based SAAS solution. This option was not selected as it was a high-cost option. (5) Utilize the existing Service Suite solution currently deployed for similar work processes in Gas Transmission. Service Suite is in other Gas and Electric departments. The Service Suite solution is the preferred option because it is a proven solution at the Company and provides the mobility and digital benefits at a lower cost.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/10/2023	4/30/2023	6/30/2023	2/24/2024
	In-Service/Go-Live	**Closeout**	
	2/24/2024	3/31/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	$0.878	-	-	-	-	-	-	$0.878
O&M	$0.006	$0.137	$0.025	$0.025	$0.025	$0.025	$0.025	-	$0.269
Total Cost of Ownership	$0.006	$1.015	$0.025	$0.025	$0.025	$0.025	$0.025	-	**$1.147**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.006	$1.015	-	-	-	-	-	-	**$1.020**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.000	$0.000	-	-	-	-	-	-	**$0.000**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.006	$1.015	-	-	-	-	-	-	**$1.021**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	$(0.208)	$(0.208)	$(0.208)	$(0.208)	$(0.208)	-	**$(1.041)**
	Initial	$0.006	$0.137	$0.025	$0.025	$0.025	$0.025	$0.025	-	**$0.269**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.006	$0.137	$(0.183)	$(0.183)	$(0.183)	$(0.183)	$(0.183)	-	**$(0.772)**
Cap+COR	Reduction	-	-	$(0.021)	$(0.021)	$(0.021)	$(0.021)	$(0.021)	-	**$(0.103)**
	Initial	-	$0.878	-	-	-	-	-	-	**$0.878**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.878	$(0.021)	$(0.021)	$(0.021)	$(0.021)	$(0.021)	-	**$0.775**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.243

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Employee Engagement improves as the more tech savvy candidate pool for these positions are looking for mobile tools to help them do their jobs.
Intangibles	Productivity increases by using electronic work packages and reducing the need to return to desktop kiosks for updates. With the electronic work packages, (1) employees have remote access to manuals such as the Gas Operations Manual for Gas Compression and local maintenance procedures to reference standard work, (2) it eliminates multiple physical hand-offs of work documents related to the work management process and (3) it frees up planners' time to focus on long-range and outage planning to adhere to goals such as the Periodic Factor metric and Gas Flow Deliverability goal for Gas Compression. Productivity can also be tracked and measured for further improvements. This level of tracking is not possible with the current process and information.
Intangibles	Quality is improved and rework decreases when updates are performed right at the time and place of the work instead of afterwards. For Gas Compression, it (1) eliminates the manual process to update work scope and ensures access to the most up-to-date work order package, (2) allows crews to input SAP Notifications while at the jobsite for improved accuracy of data collected (3) provides the ability to collect asset condition data accurately at the jobsite to feed the data lake for asset health, and allows for the development of electronic code forms with built-in validation to improve quality of compliance data being collected.
Intangibles	Safety is increased as the most current information is at the work site in the mobile device versus a printed procedure.
Avoided Costs	The labor savings on time charging on a toughpad versus re-entering time later in office is 10 mins/day/employee savings from the 15 mins/employee per day it currently takes to enter time. Employees currently take 15mins per day to enter time. 59 Gas Compression employees would save 10mins/day = .17Hour x 230 work days a year x 59 employees = 2,306.9 hours avoided per year * $61 Standard Labor Rate = $140,720.90 Avoided O&M Costs
Risk Mitigation	The project will mitigate the risk of work errors from using outdated procedures especially for performing Gas Compression code work inspections using electronic forms. Electronic forms will improve validation of required inspection data, thereby reducing the risk of MPSC audit findings and possible regulatory fines. It also reduces safety risk by having the ability to have jobsite access to Emergency Plans to meet corporate safety requirements.
Avoided Costs	With this project there are avoided costs in Gas Compression from eliminating paper work package assembly. The time for 6 exempt planners is 2 days per month; 8 planners x 2 days x 8 hours = 128 hours per month. The avoided cost for exempt planners is calculated at 128 hours/month x $48/hour x 12 months = $73,728 per year. Their capital/O&M split is 25/75 which breaks down to avoiding $18,432 in capital and $55,296 in O&M. Six non-exempt admins spend 8 hours/month; 6 admins x 8 hours = 48 hours per month. The avoided cost for non-exempt admins is calculated at 48 hours/month x $25/hour x 12 months = $14,400 per year. Their capital/O&M split is 15/85 which breaks down to avoiding $2,160 in capital and $12,240 in O&M.
Technology Capability	Work Management

Gas Construction Operations Enablement

Report Pulled: 11/1/2024 **Item ID: 6722**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias EIRP Technology Enablement, Enhanced Infrastructure Replacement Program Technology Enablement, Gas Construction Operations Enablement

Description The project will implement an electronic work management solution that will enable Gas Construction Operations employees to assign, manage, and complete field work orders, eliminating the manual processes used. The work management system will also enable improved time tracking and reporting.

Portfolio Gas Delivery Systems > Gas Operations > IT Projects > IT Projects > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-OPERATIONS

WORK OBJECTIVES

Problem Statement The Gas Construction Operations department has operated on a paper process for work order completion since their initiation. Originally the work group was to be a temporary workforce; however ongoing improvements for the gas network have extended the need for the department. The current paper process creates additional work to produce and distribute to field operations. Also, the return of the completed paper process has a risk of human errors, lost paperwork, data lags, and readability. These manual processes often require additional contacts to field leaders and field employees to post-verify information. This project will allow the electronic system to automatically process meter orders in SAP, improving accuracy for Customers.

Objectives The project will add value by: (1) improving visibility to work locations of crews and job status updates in real time, (2) standardizing employee time-sheet management, (3) reducing closeout time by reducing data entry, (4) eliminating efforts to hand off paper copies of meter work orders, (5) reducing billing processing lag time for customers through direct updates on electronic forms, and (6) improving customer satisfaction with more timely meter installation dates.

Scope The scope of the project includes: (1) implementing an electronic work management solution for Gas Construction Operations, (2) enabling Gas Construction employees to assign, manage, and complete field work orders, and (3) developing the interfaces for management of the Gas Construction business unit.

Alternatives Alternatives considered include: (1) continuing with the existing paper process, and (2) SAP direct form order entry and completion. These two alternatives were not chosen because manual workarounds will not improve safety or reduce job and administrative time, and SAP does not support entry of information without cellular connectivity. In addition, with direct SAP, a method of work assignment would need to be developed. The electronic work management solution was chosen because it will improve safety and reduce job and administrative time, while supporting information entry without cellular connectivity. This solution is a Company standard which simplifies the implementation and keeps ongoing maintenance costs down.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2021	3/1/2021	6/1/2021	4/4/2022
	In-Service/Go-Live	**Closeout**	
	4/11/2022	5/9/2022	

FUNDING SUMMARY

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Cap+COR	$0.249	$1.604	$0.003	-	-	-	-	-	$1.856
O&M	$0.069	$0.083	-	$0.107	$0.107	$0.107	$0.107	-	$0.579
Total Cost of Ownership	$0.318	$1.687	$0.003	$0.107	$0.107	$0.107	$0.107	-	**$2.435**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.286	$0.050	-	-	-	-	-	-	**$0.337**
Outside Services	-	$1.508	-	-	-	-	-	-	**$1.508**
Business Expense/Overheads	$0.032	$0.129	$0.003	-	-	-	-	-	**$0.164**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.318	$1.687	$0.003	-	-	-	-	-	**$2.008**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2021	2022	2023	2024	2025	2026	2027	2028 +	Total
O&M	Reduction	-	$(0.020)	$(0.020)	$(0.020)	$(0.020)	-	-	-	**$(0.080)**
	Initial	$0.069	$0.083	-	$0.107	$0.107	$0.107	$0.107	-	**$0.579**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.069	$0.063	$(0.020)	$0.087	$0.087	$0.107	$0.107	-	**$0.499**
Cap+COR	Reduction	-	$(0.360)	$(0.360)	$(0.360)	$(0.360)	$(0.360)	-	-	**$(1.800)**
	Initial	$0.249	$1.604	$0.003	-	-	-	-	-	**$1.856**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.249	$1.244	$(0.357)	$(0.360)	$(0.360)	$(0.360)	-	-	**$0.056**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.295

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Implementing this project will reduce human error and lost paper work by providing an electronic work management solution that will eliminate the manual processes currently being used.
Technology Capability	Work Management

Gas Distribution Probabilistic Risk Model

Report Pulled: 11/1/2024 **Item ID: 14010**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Gas Transmission Probabilistic Risk Model, Gas Distribution Probabilistic Risk Model

Description The project will implement a risk analysis model for comprehensive predictive risk analysis and modeling on gas distribution pipeline assets.

Portfolio Gas Delivery Systems > Gas Engineering & Supply > IT Projects > IT Projects > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-GAS

WORK OBJECTIVES

Problem Statement

Relative risk models are unit-less measures of risk derived from input information using qualitative data and ordinal scales to produce "risk index" scoring; in simple terms, the relative risk model does not provide true statistical measures. The risk assessment used in the current model provides a score for likelihood, consequence, and risk that is relevant only in comparison to other scores. While the outputs provide a sense of relative risk when comparing one pipeline with another, the scores do not provide quantitative scores for probability, frequency, or expected loss of events. Although pipeline operators commonly use relative risk models, the quality of the relative risk ranking relies on subject matter expert inputs, human inferences, and opinions.

Objectives

Completion of this project will provide value to both the Company and its customers. Each party will benefit from safety improvements and risk mitigation through statistically-based risk modeling that leads to more informed pipeline replacement or improvement projects. Implementing probabilistic risk modelling supports the changes planned for in the Company's Natural Gas Delivery Plan (NGDP), including the Company Gas Management Safety System (GSMS). GSMS incorporates the Company's plan to implement the American Petroleum Institute (API) Recommended Practice 1173 (Pipeline Safety Management Systems). Additionally, the implementation of a probabilistic risk model will: (1) calculate quantitative risk scores that include measures of probability, frequency, or expected loss of events; and (2) configure multiple data sources to make advanced statistical calculations for interacting threats, both of which allow the Company to make more informed decisions based on improved quality inputs in a measurable model; and (3) provide information for better decisions on Capital project improvements and integrity management. Unlike the current unit-less relative model a probabilistic model will be a unit based risk score, specifically in the unit of dollars, improving efficiency in interpreting risk results for business decisions.

Scope

The project scope encompasses the implementation of a probabilistic risk model for gas distribution. The project will: (1) install and configure risk model; (2) configure multiple data sources; and (3) develop reports and dashboards.

Alternatives

Alternatives considered for the project include: (1) Implement a custom, Excel-based probabilistic risk model through a consulting effort. This alternative was not selected because although the effort minimizes the IT cost of the project, the model requires the creation of secondary data sources, leading to multiple "sources of truth". (2) Implement a custom built probabilistic risk model. This alternative was not selected because the custom built solutions analyzed are not mature and have not been widely tested with transmission operators. (3) Implement a SaaS based solution. The option of implementing the SaaS probabilistic risk model was chosen because it is the most cost-effective long-term implementation approach, providing commercial, off-the-shelf capabilities, industry-proven and upgradable technology, and ongoing vendor support.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
10/1/2025	10/15/2025	11/15/2025	5/1/2026
	In-Service/Go-Live	**Closeout**	
	9/30/2027	10/31/2027	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$2.431	$1.040	$1.040	-	-	-	-	-	$4.511
O&M	$0.026	$0.068	$0.107	$0.102	$0.102	-	-	-	$0.405
Total Cost of Ownership	$2.458	$1.108	$1.146	$0.102	$0.102	-	-	-	**$4.916**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.217	$0.427	$0.424	-	-	-	-	-	**$1.069**
Outside Services	$0.192	$0.350	$0.350	-	-	-	-	-	**$0.892**
Business Expense/Overheads	$0.248	$0.330	$0.372	$0.102	$0.102	-	-	-	**$1.154**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$1.800	-	-	-	-	-	-	-	**$1.800**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$2.458	$1.108	$1.146	$0.102	$0.102	-	-	-	**$4.916**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.026	$0.068	$0.107	$0.102	$0.102	-	-	-	**$0.405**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.026	$0.068	$0.107	$0.102	$0.102	-	-	-	**$0.405**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.431	$1.040	$1.040	-	-	-	-	-	**$4.511**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.431	$1.040	$1.040	-	-	-	-	-	**$4.511**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Asset Management
Risk Mitigation	Implementation of a probabilistic risk model mitigates risk through a comprehensive, statistical analysis of threats to pipe segments, ensuring focus on solving the right problems and resolving the highest risk items.
Risk Mitigation	Prevention of distribution incidents (i.e. home explosions) and avoided cost of these incidents: A probabilistic risk model would increase our ability to identify potential incidents before they occur. An incident such as a home explosion can have a significant impact on the company, including the dollars cost to repair the damage as well as the impact to the public's perception of the Company. It is anticipated that there will be a reduction in the potential for types of incidents with this improved tool. Although the model will not necessarily eliminate the possibility that these types of incidents could occur in the future, the model will reduce the likelihood that they will occur because we have a better understanding of our system. The project investment could avoid actual and reputational costs by potential avoiding one of these incidents. In addition the new model will help better quantify the cost of an incident.
Intangibles	Quality improvement - Implementation of a probabilistic risk model provides quantifiable results that are more reliable, transparent, and understandable, rather than relatively ranked; improving confidence in data and leading to improved decision-making for strategic planning, financial planning, and regulatory oversight.
Intangibles	Waste elimination through potential productivity improvements. A true statistical model may eliminate workarounds with the current model that are necessary to support planning efforts by reducing investigation time and increasing user expertise through quantitative analysis and insight to core model functionality.

Gas Distribution ProjectWise

Report Pulled: 11/1/2024 **Item ID: 10681**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , ProjectWise for Gas Distribution, Gas Distribution ProjectWise

Description ProjectWise is a suite of project collaboration software for engineering projects currently in use as the Company by gas transmission and generation engineering teams. It is capable of bundling, managing and handling the versions of records and documents related to designs, proposals, contract resources and record-keeping. The Gas Distribution ProjectWise project will expand the implementation of the software to gas distribution and be used to facilitate a management of change process for gas engineering design and gas system configuration changes.

Portfolio Gas Delivery Systems > Gas Engineering & Supply > IT Projects > IT Projects > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-GAS

WORK OBJECTIVES

Problem Statement

SharePoint and a centralized Company data store are currently used as a data warehouse for gas distribution engineering design documentation. The current solution has limited ability to meet the functionality required for managing and approving the files and drawings that are unique to engineering design work. Gaps include: (1) inability to track design edits and document design change authorization approval; (2) inability to manage multiple outage windows and potential impact of planned projects; (3) inability to track gas system configuration changes, both temporary and permanent; (4) no current standardized structure of project documents for ease of viewing/editing; and (5) no current structure for tracking as-built/final record completion. In addition, the engineering teams lack an effective tool to centralize the management of change processes for gas engineering design and gas system configuration, leading to unapproved changes to projects without proper knowledge and authorization. Without the proper controls and versioning in place, the opportunity for rework is enhanced causing extended project time for completion, negative impacts on other projects and increased costs.

Objectives

Completion of this project will provide value to the Company through: (1) comprehensive documentation of all design review changes from key technical Subject Matter Expert (SME) groups, ensuring that the final design is inclusive of all approved changes; (2) end to end workflow tracking and approval sign-off from initial design and engineering through field operations and final sign-off, providing for a centralized historical record that is traceable and verifiable; (3) consistent gas technical records across project and asset lifecycles; (4) increasing public and employee safety and regulatory compliance with complete and accurate records that are readily accessible and easily searchable; (5) providing visibility to and improving tracking for system outage windows and/or temporary pressure changes/reductions providing the ability to align outage schedules with distribution construction schedules; (6) tracking temporary and permanent gas distribution system configuration changes in a centralized repository; (7) maintaining spatial relationships within drawings and documents such that all documents pertinent to a geographic location can be quickly accessed and maintained; (8) providing a universal system of record for complex operating procedures; (9) creating a universal system of record for all construction prints; (10) centralizing tracking of Supervisory Control and Data Acquisition (SCADA) commissioning and decommissioning activities; (11) tracking project as-built and final project record completion; and (12) providing a centralized repository for document retention, archival and version tracking, resulting in records that are traceable and retrievable. Collectively, these items support the Company's implementation of the American Petroleum Institute (API) Recommended Practice 1173 Pipeline Safety and adherence to regulatory requirements. The project provides additional value by implementing a management of change tool with capabilities that can be replicated in other organizations, including gas engineering metering and regulation, gas system integrity, and gas transmission.

Scope

The scope of this project encompasses implementation of ProjectWise software modules for use by Gas Distribution Engineering. The project will: (1) configure the software modules within the application, and (2) design and develop integrations with other Company systems.

Alternatives

Alternatives considered include: (1) Continue with current SharePoint and shared data store warehousing solution for versioning of Gas Engineering designs and system outage windows. This alternative was not selected because it does not resolve the identified problems. (2) Develop and implement an in-house solution. This alternative was not selected due to costs and lack of expertise in developing a custom solution. (3) Implement ProjectWise software. This alternative was selected for the following reasons: (1) ProjectWise is available in a Software as a Service (SaaS) solution with out of the box capabilities, and (2) ProjectWise aligns with the Company direction as it has been implemented and is in use in other areas of the Company including Generation and Gas Transmission.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/1/2022	3/1/2022	7/1/2022	10/3/2022
	In-Service/Go-Live	**Closeout**	
	11/30/2022	12/15/2022	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	-	$0.699	$0.162	-	-	-	-	-	$0.862
O&M	$0.200	$0.036	$0.002	$0.128	$0.163	$0.178	-	-	$0.708
Total Cost of Ownership	$0.200	$0.736	$0.165	$0.128	$0.163	$0.178	-	-	**$1.570**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	$0.024	$0.100	$0.141	-	-	-	-	-	**$0.264**
Outside Services	$0.163	$0.566	$0.014	-	-	-	-	-	**$0.743**
Business Expense/Overheads	$0.013	$0.070	$0.010	-	-	-	-	-	**$0.093**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.001	-	-	-	-	-	-	-	**$0.001**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.200	$0.736	$0.165	-	-	-	-	-	**$1.101**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.200	$0.036	$0.002	$0.128	$0.163	$0.178	-	-	**$0.708**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.200	$0.036	$0.002	$0.128	$0.163	$0.178	-	-	**$0.708**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.699	$0.162	-	-	-	-	-	**$0.862**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.699	$0.162	-	-	-	-	-	**$0.862**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Asset Management
Risk Mitigation	Implementation of the solution supports the Company's adoption of the American Petroleum Institute (API) Recommended Practice 1173 (Pipeline Safety Management Systems) that is being implemented as part of the Company's Gas Safety Management System.
Risk Mitigation	Increased public and employee safety and regulatory compliance with complete and accurate records that are readily available through the new solution.
Risk Mitigation	Mitigate the risk associated with incorrect, incomplete or missing design changes by establishing document retention, archival and version tracking resulting in records that are traceable and verifiable.
Risk Mitigation	Mitigate the risk with having different versions of engineering designs by providing a single source of truth for Gas Distribution technical records.
Risk Mitigation	Mitigates the risk of losing or not finding project documents because the new solution has the ability to maintain spatial relationships within drawings and documents such that all documents pertinent to a geographical location can be quickly located and maintained

Gas Leak Asset and Work Management

Report Pulled: 11/1/2024 **Item ID: 6763**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias GCCP Leak Asset and Work Management, Gas Leak Asset and Work Management

Description The project will implement functionality to automate gas leak compliance tasks and track all gas leak activity in the Gas Geographic Information System (GIS), creating a single system of record for gas leak data, and providing a spatial display of leak data to improve leak management visibility.

Portfolio Gas Delivery Systems > Gas Engineering & Supply > IT Projects > IT Projects > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-GAS

WORK OBJECTIVES

Problem Statement

The gas leak process utilizes two systems to complete work and monitor gas leak compliance: SAP and Inspection Manager. Gas leak information is manually transferred between SAP and Inspection Manager and vice versa by compliance technicians. An internal audit identified 7818 leak orders, resulting in a 61% defect rate, with inconsistent information recorded between SAP and Inspection Manager. Lack of quality controls to help ensure accurate leak information across systems may inhibit managements ability to effectively monitor gas leaks and could result in leaks not being re-classified or repaired in a timely manner. This has regulatory compliance and safety impacts such as missed compliance dates which may result in fines and increased public safety risk resulting from untimely or missed leak repairs.

Objectives

The project provides value to both the Company and its customers, including: (1) improving productivity and leak location accuracy; (2) enabling near-real time reporting and automated metric reporting on open leak backlog; (3) creating one system of record for all leak assets in GIS; (4) implementing quality improvements for scheduling and routing of leak crews; (5) reducing risk of future audit findings or non-compliance resulting from duplicate open leak orders; (6) optimizing resource allocation for gas service posting team by eliminating manual posting of leak repairs in GIS; (7) optimizing resource allocation for the gas compliance team by eliminating the posting of leak repairs in Inspection Manager; and (8) streamlining the leak survey workflow to improve the human struggle caused by use of paper maps and manual processes for leak order tracking.

Scope

The scope of this project includes: (1) design and implementation of an integration between the asset system and the work management system to create, update, and manage leak maintenance, repair, and emergent orders and inspection schedules through the Enterprise Service Bus (ESB) or similar; (2) configuration of new SAP and Service Suite work order completion forms required to support new work processes; (3) updating the business intelligence dataset to support reporting; (4) reconfiguring workflows in Inspection Manager to capture all leak data from GIS; (5) design and implement a solution to replace the use of paper maps in the leak survey process; (6) implementing a workflow to communicate first time and repeated customer contacts for a given leak; (7) implementing an open leak order geospatial map of all open leak orders, utilized across office and field technology; (8) creating a system indicator that flags duplicate leak orders at the same location; and (9) implementing functionality to provide visibility through a listing of all open leak orders within a specified radius.

Alternatives

Five alternatives were considered for the project: (1) Implement a Quality Assurance/Quality Control (QAQC) process to ensure data is consistent between both SAP and Inspection Manager. This alternative was not selected because it requires an increase in labor costs for manual reporting and data checks. In addition, as demonstrated by the audit, manual processes, even manual QAQC processes, are subject to human error, and each error creates safety and noncompliance risk. (2) Implement a Robotic Process Automation (RPA) to sync data. This solution was explored but is not viable because the business processes are too complex. (3) Implement a new GIS-based compliance solution that can be integrated with SAP. This alternative is too costly, given recent investment in the current Inspection Manager solution. (4) Defer project implementation. The alternative selected is to implement this project now, rather than later, as a result of recent gas leak red audit findings. (5) Implement functionality to automate gas leak compliance tasks and track all gas leak activity in the GIS. This alternative was selected because it leverages existing solutions in a new way, optimizing resources and technology investment. The use of Cloud technology was not considered due to the enhanced functionality being added to systems and applications that are already on-premise.

DATES (phase end)

Initiation 11/1/2023	**Project Plan & Scope Definition** 12/12/2023	**Final Engineering, Planning & Design** 4/1/2024	**Execution** 11/1/2024
	In-Service/Go-Live 11/30/2024	**Closeout** 12/18/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	$0.050	-	$0.050
O&M	$0.005	$0.001	$0.013	$0.013	$0.013	$0.013	$0.013	-	$0.072
Total Cost of Ownership	$0.005	$0.001	$0.013	$0.013	$0.013	$0.013	$0.063	-	**$0.122**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.004	$0.001	-	-	-	-	$0.050	-	**$0.056**
Outside Services	$0.000	-	-	-	-	-	-	-	**$0.000**
Business Expense/Overheads	$0.000	$0.000	-	-	-	-	-	-	**$0.000**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.005	$0.001	-	-	-	-	$0.050	-	**$0.056**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.005	$0.001	$0.013	$0.013	$0.013	$0.013	$0.013	-	**$0.072**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.005	$0.001	$0.013	$0.013	$0.013	$0.013	$0.013	-	**$0.072**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	$0.050	-	**$0.050**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	$0.050	-	**$0.050**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Asset Management
Avoided Costs	Gas Distribution and Service leak classification reasonable expectancy (time estimate for completing the work) would be reduced due to better information being available to find the leak, because the employees will already know where the leak is versus spending time trying to find the leak again. It is estimated that annually approximately 2,500 leak investigation orders are duplicates from already existing leak orders 40% of the leaks are investigated by Distribution crews, and 60% are investigated by service workers. We could save 500 hours in reduced distribution crew labor, and 750 hours in reduced service worker labor. The expectation is that we would reduce the reasonable expectancy by 50% for each duplicate leak classification. 2,500*40%*1 hr*50%= 500 hours saved for distribution crew labor. 2,500*60%*1 hr*50%= 750 hours saved for service worker labor.
Intangibles	Implementation of a solution to replace the use of paper maps in the leak survey process will lead to improvements for scheduling and routing of leak crews.
Intangibles	Implementation of additional integration between the asset system and work management system for leak maintenance, repair and inspections will lead to improved productivity allowing gas compliance personnel to focus activity on higher value leak analysis versus time spent on data entry.
Risk Mitigation	Implementation of additional integration between the asset system and work management system will reduce the risk of future audit findings or non-compliance due to a reduction in data inconsistencies between the leak management and work order management applications
Risk Mitigation	Implementation of the application changes will reduce the risk of regulatory non-compliance due to a reduction in the duplication of open leak orders.
Avoided Costs	Leak Survey Compliance Technician would avoid 12 minutes per order of human struggle searching for new leak orders that should be tied to an already open deferred leak order allowing them to focus on higher priority work with the time saved.
Intangibles	Reconfiguring workflows in Inspection Manager to capture all leak data from GIS will enable creating one system of record for all leak assets in GIS.
Avoided Costs	Reduce gas compliance technician labor through the reduction in hours to support gas service GIS team by 2,000 hrs for compliance technician (nonexempt) to research and link leak repair orders.
Avoided Costs	Reduce gas compliance technician labor through the reduction in hours to support gas service GIS team by 6,100 hrs for compliance technician (nonexempt) to research and manually link leak classify orders to leak assessment orders in Inspection Manager and SAP.
Intangibles	Updating the business intelligence data-set will support more automated reporting on the open leak backlog.

Gas Measurement, Regulation, Pipeline, and Storage (MRPS) Report Pulled: 11/1/2024 Item ID: 6755

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias FSS Release 4 MRPS, Gas Measurement, Regulation, Pipeline, and Storage Field Work Management Enablement, Gas Measurement, Regulation, Pipeline, and Storage (MRPS) Field Work Management Enablement

Description The project will move gas MRPS work orders from the current paper process to an electronic solution that includes work management, compliance scheduling and tracking, mobile dispatch and work completion functions.

Portfolio Gas Delivery Systems > Gas Operations > IT Projects > IT Projects > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-OPERATIONS

WORK OBJECTIVES

Problem Statement The current field processes and activities within Transmission Operations are hindered by lack of technology. MRPS does not currently have a technology solution for work order processing, parts ordering, dispatch and scheduling, GPS routing, and access to Company applications. As a result, employees rely on manual paperwork processes, handoffs, and work order management. The current field device could be better utilized if not for technology limitations that hindering customer benefits and employee engagement.

Objectives The project will add value by: (1) increasing efficiency of order entry and management reporting through a digital solution rather than paperwork handoffs; (2) maintaining key compliance records without depending on paper processes and records; (3) improving productivity by eliminating the duplication waste of managing asset and compliance records management using paper binders; (4) reducing risk of MPSC non-compliance by digitizing system data, making it readily available for review and analysis by leadership; (5) increasing visibility to asset health using data available from a digital system to enable reporting and analysis; and (6) improving Safety by reducing risk to gas storage assets and adherence to standards by moving to digital systems and data. This enables future Safety initiatives such as a monthly well monitoring program that ensures accurate and timely data capture for identification and mitigation of asset risk, analysis, and data trending.

Scope The project scope includes: (1) SAP updates to enable gas MRPS work processes; (2) prioritizing agile methodology to evaluate and convert paper forms (up to 75 for compliance work, up to 75 for work order completion); (3) alignment of use with the compliance scheduling and tracking solution on routing and documenting work, tracking time, and work order costing; and (4) development of Training materials and train-the-trainer activities.

Alternatives Alternatives considered include: (1) utilize an SAP module to migrate field work orders to an electronic platform; (2) implement a new solution - Field Manager Solution, Go Canvas, ESRI, and Smart Sheet were evaluated; (3) continue manual paper-based process currently used by the gas MRPS work force; and (4) implement a Service Suite solution. The first alternative was not selected because it did not offer a scheduling solution or support information entry in offline setting, location and time tracking would need added integration, and a method of assignment and dispatch would need to be developed. The second alternative was not selected because the ad hoc applications that were evaluated were significant deviations from the field work management standard solution, reducing field crew usability through lack of integration and user adoption while increasing support complexity and cost. The third alternative was not selected because it does not eliminate the current process waste, rework, and human error risk. The alternative to implement the Service Suite solution was selected because it is the current field work management standard, providing work management scheduling capabilities, real time validation of field work order forms, and proven field crew adoption and usability resulting from four years of Service Suite usage by 2000+ Company field crews.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/4/2021	1/31/2021	2/28/2021	11/15/2022
	In-Service/Go-Live	**Closeout**	
	11/30/2022	12/23/2022	

FUNDING SUMMARY

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Cap+COR	$1.071	$1.564	$0.001	-	-	-	-	-	$2.636
O&M	$0.010	$0.001	-	$0.100	$0.100	$0.100	$0.100	-	$0.412
Total Cost of Ownership	$1.081	$1.565	$0.001	$0.100	$0.100	$0.100	$0.100	-	**$3.047**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.758	$0.143	-	-	-	-	-	-	**$0.901**
Outside Services	$0.212	$1.264	-	-	-	-	-	-	**$1.476**
Business Expense/Overheads	$0.111	$0.159	$0.001	-	-	-	-	-	**$0.270**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.081	$1.565	$0.001	-	-	-	-	-	**$2.647**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2021	2022	2023	2024	2025	2026	2027	2028 +	Total
O&M	Reduction	-	$(0.014)	$(0.014)	$(0.014)	$(0.014)	$(0.014)	-	-	**$(0.068)**
	Initial	$0.010	$0.001	-	$0.100	$0.100	$0.100	$0.100	-	**$0.412**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.010	$(0.012)	$(0.014)	$0.086	$0.086	$0.086	$0.100	-	**$0.343**
Cap+COR	Reduction	-	$(0.048)	$(0.048)	$(0.048)	$(0.048)	$(0.048)	-	-	**$(0.242)**
	Initial	$1.071	$1.564	$0.001	-	-	-	-	-	**$2.636**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.071	$1.516	$(0.047)	$(0.048)	$(0.048)	$(0.048)	-	-	**$2.394**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.913

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	CE Way Maturity - The project enables data to be more accessible electronically so that it can be visualized, access to data provides increased visibility to problem solving, and Service Suite forms allow for increased standardization
Intangibles	Gas Technical Information Excellence (GTIE) Records Accuracy - The project enables real-time record updates and increased accuracy.
Avoided Costs	Safety and Productivity - Measurement and Regulation: 25min/day increase in productivity = $40K O&M Avoid Costs
Avoided Costs	Safety and Productivity - Pipeline: 25min/day increase in productivity = $63K O&M Avoided Costs
Avoided Costs	Safety and Productivity: Storage - 25min/day increase in productivity = $74K O&M Avoid Costs
Risk Mitigation	This program will enable alignment with Underground Gas Storage industry for acceptable gas storage well monitoring program / practices in adherence to API1171 RP. In addition, doing this project reduces MPSC non-compliance fees, reducing the risk of these fees to the company.
Technology Capability	Work Management

Gas SCADA Software Solution

Report Pulled: 11/1/2024 **Item ID: 6756**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias Gas SCADA System, Gas SCADA Software Solution

Description The Gas Supervisory Control And Data Acquisition ("SCADA") software solution project will replace the current Gas SCADA Software with a more standardized software package enabling the Company to more efficiently meet Federal and MPSC requirements.

Portfolio Gas Delivery Systems > Gas Engineering & Supply > IT Projects > IT Projects > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement

The current Gas SCADA software solution was originally implemented in 2000 and was based on the gas system requirements at that time. While the solution has been maintained since its implementation, the Company's gas system has outgrown the current capabilities. As the solution ages, there is increased effort required to address obsolete application and database software architecture, and enhancements to the system are limited. To address the capability gaps, custom interim fixes and integrations have been developed where each requires maintenance and support. This environment adds complexity and cost to solution upgrades and troubleshooting issues. The current Gas SCADA solution will limit the ability to invest in digital solutions for increased system health monitoring and preventative maintenance capabilities due to the complexity to integrate these future capabilities with it.

Objectives

The project will add value by: (1) reducing risk of non-compliance by improving the ability to document and follow State and Federal requirements, improving customer safety; (2) improving efficiency and reliability when performing routine software upgrades, because standard out-of-the-box software has less risk of breaking during upgrades, as opposed to more custom-coded software; (3) reducing maintenance costs due to fewer individual software programs and less custom code; (4) improving Gas Control management capabilities that support the Federal and MPSC requirements for gas pipeline and Gas Distribution companies; (5) improving reliability by using proven gas industry standardized software with configuration features, rather than a fully customized system that has the possibility of being impacted by the next version update; (6) purchasing standard, out-of-the-box software that meets a high percentage of requirements and avoids multiple custom applications and specially coded programs to achieve results; and (7) providing a basis for capturing data required for use in computer-based preventative maintenance programs and more predictive technologies. In addition, implementing industry-specific software helps the collective gas industry users to encourage the vendor development of future version enhancements, which adds more value to gas industry users. The comprehensive Gas SCADA system is used to monitor and control the operating conditions of the transmission and distribution gas systems. The Gas SCADA system includes remote terminal units (RTUs), field devices (i.e. valves, meters, odorizers), and computers running SCADA software. This scope covers the Gas SCADA software solution only.

Scope

The project scope includes the following: (1) significant planning, including consulting assistance, to define the implementation strategy for the effort, given the magnitude of the technology effort; (2) selection and implementation of a new Gas SCADA software solution; (3) planning of a phased rollout of new hardware and software; and (4) retirement and decommissioning of the legacy gas SCADA solution and equipment once the new system is fully tested and operational.

Alternatives

Alternatives considered include: (1) continue to maintain the current solution, at the risk of increasing reliability issues that result in controlling and monitoring the Company's gas system; (2) invest in enhancing the existing Gas SCADA software solution which would introduce additional custom development and more specialized functions that may not be supported in future vendor releases; and (3) replace the solution with a gas SCADA software solution that meets requirements to support the NGDP. Alternative three has been selected to ensure sustainability for this critical solution. The current legacy system is operating at well beyond its original design specification, so the potential points of failure are not fully known or understood. If the SCADA project is not completed, the legacy system could become unstable and impact Gas Control's ability to operate and monitor real-time system conditions, maintain safe operations, and compliance with regulatory requirements. It could also impact the ability to commission new facilities which require remote monitoring or control or cause the need for 24/7 manual field monitoring of certain facilities.

DATES (phase end)

Initiation 1/1/2022	**Project Plan & Scope Definition** 10/31/2023	**Final Engineering, Planning & Design** 5/30/2024	**Execution** 6/24/2024
	In-Service/Go-Live 11/30/2025	**Closeout** 12/15/2025	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	-	$1.950	$8.028	$8.039	-	-	-	-	$18.016
O&M	$0.632	$0.161	$0.481	$1.032	$0.300	$0.300	$0.300	$0.300	$3.505
Total Cost of Ownership	$0.632	$2.111	$8.508	$9.071	$0.300	$0.300	$0.300	$0.300	**$21.521**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	$0.045	$0.203	$1.386	$1.113	-	-	-	-	**$2.747**
Outside Services	-	$0.221	$4.958	$4.052	-	-	-	-	**$9.231**
Business Expense/Overheads	$0.587	$0.032	$0.468	$1.264	-	-	-	-	**$2.351**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.947	$1.026	$0.174	-	-	-	-	**$2.147**
Licenses, Permits & Fees	-	$0.709	$0.669	$2.467	-	-	-	-	**$3.845**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.632	$2.111	$8.508	$9.071	-	-	-	-	**$20.321**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.632	$0.161	$0.481	$1.032	$0.300	$0.300	$0.300	$0.300	**$3.505**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.632	$0.161	$0.481	$1.032	$0.300	$0.300	$0.300	$0.300	**$3.505**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$1.950	$8.028	$8.039	-	-	-	-	**$18.016**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$1.950	$8.028	$8.039	-	-	-	-	**$18.016**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	Medium	Medium	Server and Network Architecture is not current and does not meet current business needs due to: (1) SCADA Software and Operating System limitations require operation of Citect SCADA under a console session with administrative privileges which increases security risk; (2) SCADA Input/Output (I/O), SCADA Trend, and SCADA Alarm processes are hosted on the server as individual executables rather than services; and (3) SCADA functionality is hosted on a single server (with remote redundancy). Additional inefficiencies with the current solution include: (1) SCADA Services for Human Machine Interface (HMI), I/O, Trend, Alarm, Report; (2) file Services for Gas Control Procedure Documents, SCADA Configuration and Procedure Documents; (3) database Services - Reports, SCADA Configuration, SCADA HMI Configuration, SCADA HMI Navigation; (4) failover to Backup SCADA I/O requires manual processes and increases overall system outage time; and (5) current configuration is not appropriate for migration to an off-site data center

OTHER VALUE

Type	Description
Intangibles	A new SCADA software solution offers ability to: (1) improve On Screen Data quality; (2) implementation of Alarm Prioritization based on alarm severity; (3) GIS integration; (4) ability for schematic diagrams to include direction of flow; and (5) use of better screen resolution
Technology Capability	Energy Portfolio Planning
Avoided Costs	Gas Controller workload reduction due to the enhanced capabilities described within the new standardized software would be realized. New software functionality includes the ability to input data for log/archive purposes within the SCADA user interface. Current Controller documentation software, which exists on a separate corporate system and requires the Controller to move between secure SCADA environment and corporate computer systems, could be incorporated as a single working environment with the new SCADA system. Assumption is that Control Room is 24x7, 3 controllers x 24 hours x 10 min/hr time saved
Risk Mitigation	Implementation of a new SCADA software solution will mitigate the risk that our current SCADA solution may limit our ability to modernize the remote terminal unit (RTU) and electrical systems at city gates and regulator stations due to the customization that may be required to support this new equipment.
Risk Mitigation	Implementation of a new SCADA software solution will mitigate the risk with our current SCADA solution encountering performance issues as additional SCADA installations are completed at regulator stations. The Over Pressure Protection (OPP) program plans to install SCADA at 16-22 stations annually to reduce the possibility of MAOP (Maximum Allowable Operating Pressure) exceedance. The program has yielded past success as being partly responsible for decreasing the number of MAOP exceedances from over 30 annually to 1 in 2019.
Risk Mitigation	The current SCADA software solution requires changes to be performed in a linear fashion, which will create greater risk in implementing the Natural Gas Delivery Plan initiatives for adding remote control monitoring capabilities and accelerating the retirement of vintage materials
Intangibles	Upgrade or replacement of the old Gas SCADA software solution will improve stability and help to avoid issues with lost and unrecoverable data which could be considered non-compliant in reporting to the MPSC.

Gas Storage Probabilistic Risk Model

Report Pulled: 11/1/2024 **Item ID: 10513**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Gas Storage Probabilistic Risk Model

Description The Gas Storage Probabilistic Risk Model project will implement a risk analysis model for comprehensive predictive risk analysis and modeling on gas storage wells.

Portfolio Gas Delivery Systems > Gas Engineering & Supply > IT Projects > IT Projects > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-GAS

WORK OBJECTIVES

Problem Statement

The current Gas Storage model is a relative risk model that equates risk to dollars from input information using qualitative data and ordinal scales to produce a "risk ranking". In simple terms, the relative risk model is not capable of creating a statistically significant result. The risk assessment used in the current model provides a ranking for likelihood, consequence, and risk that is relevant only in comparison to other rankings. While the outputs provide a sense of relative risk when comparing one well to another, the ranks do not provide anything qualitative that relates to the failure of wells. Also, the current transmission model does not meet the requirements of the MPSC, as indicated in a letter of noncompliance (dated January 15, 2019), and rule-making for storage systems has historically followed transmission rule-making. Lastly, the current model introduces risk in PHMSA findings as a non-probabilistic model.

Objectives

Completion of this project will provide value to both the Company and its customers. Each party will benefit from safety improvements and risk mitigation through statistically-based risk modeling that leads to more informed well improvement projects and improved targeted plug and abandonment projects. Implementing probabilistic risk modelling supports the changes planned for in the Company's Natural Gas Delivery Plan (NGDP), including the Company Gas Management Safety System (GSMS). GSMS incorporates the Company's plan to implement the American Petroleum Institute (API) Recommended Practice 1173 (Pipeline Safety Management Systems).
Additionally, the implementation of a probabilistic risk model will: (1) calculate quantitative risk scores that include measures of probability, frequency, or expected loss of events, and (2) configure multiple data sources, to make advanced statistical calculations for interacting threats, both of which allow the Company to make more informed financial and strategic decisions based on improved quality inputs and mitigate the risk of PHMSA findings. The probabilistic model will rank the wells in risk-associated dollars making it easier to interpret risk results for the purpose of making business decisions. Furthermore, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has identified the probabilistic risk model as a potential best practice for storage operators over other risk models (PHMSA Pipeline Risk Modeling white paper, dated May 9, 2018), so the project adds value by aligning with industry best practices.

Scope

The project scope encompasses the implementation of a probabilistic risk model for gas storage wells. The project will: (1) install and configure risk model; (2) configure multiple data sources; and (3) develop reports and dashboards.

Alternatives

Alternatives considered include: (1) continue the use of the relative risk model, but invest in substantial effort to continually manually managing data inputs and quality checks (2) implement a custom, Excel-based probabilistic risk model through a consulting effort; (3) implement an on-premise probabilistic risk model, and (4) implement a cloud-based model. The first alternative was not selected because although the manual effort is possible, it is becoming increasingly difficult to complete as the model utilizes more data sources that need to be annually updated and validated. The second alternative was not selected because although the effort minimizes the IT cost of the project, the model requires the creation of secondary data sources, leading to multiple "sources of truth". The on-premise solutions analyzed are not mature and have not been widely tested with transmission operators, so alternative three was not selected. The fourth alternative of implementing the cloud-based probabilistic risk model was chosen because it is the most cost-effective long-term implementation approach, providing commercial, off-the-shelf capabilities, industry-proven technology, and an ongoing vendor support and upgraded model.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/3/2023	3/1/2023	7/31/2023	8/31/2024
	In-Service/Go-Live	**Closeout**	
	9/30/2024	10/31/2024	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	-	$0.908	$0.620	-	-	-	$0.050	-	$1.578
O&M	-	$0.115	$0.010	$0.103	$0.103	$0.103	$0.020	-	$0.456
Total Cost of Ownership	-	$1.023	$0.630	$0.103	$0.103	$0.103	$0.070	-	**$2.034**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	-	$0.003	$0.031	-	-	-	$0.070	-	**$0.104**
Outside Services	-	$0.466	$0.566	-	-	-	-	-	**$1.032**
Business Expense/Overheads	-	$0.023	$0.033	-	-	-	-	-	**$0.056**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.532	-	-	-	-	-	-	**$0.532**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$1.023	$0.630	-	-	-	$0.070	-	**$1.723**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.115	$0.010	$0.103	$0.103	$0.103	$0.020	-	**$0.456**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.115	$0.010	$0.103	$0.103	$0.103	$0.020	-	**$0.456**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.908	$0.620	-	-	-	$0.050	-	**$1.578**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.908	$0.620	-	-	-	$0.050	-	**$1.578**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Asset Management
Avoided Costs	Assumes 540 hours in annual avoided labor due to reduced labor efforts in Gas Engineering & Supply areas for running existing risk models. The new model decreases 10-15 hours of data management and analysis per well, and assumes about 40-50 wells per year. The relative risk model utilizes large sets of data that are not consumed by any other company stakeholders. These are scoring-based data sets that are updated every time there is a change to the pipeline and periodically throughout the year. It is estimated that approximately 540 hours a year are spent updating these data sets, which can be avoided after the new model is implemented.
Risk Mitigation	Implementation of a probabilistic risk model mitigates risk through a comprehensive, statistical analysis of threats to wells, ensuring focus on solving the right problems and resolving the highest risk items.
Risk Mitigation	Prevention of wells failures and voided cost of ruptures: A probabilistic risk model would increase our ability to identify potential failures before they occur. A failure such as a well blowout can have a significant impact on the company, including the dollar cost to repair the damage as well as the impact to the supply of gas to the system and the public's perception of the Company and would cause a major unplanned release of methane. It is anticipated that there will be a reduction in the likelihood of these types of failures with this improved tool. Although the model will not necessarily eliminate the possibility that these types of ruptures will occur in the future, the model will reduce the likelihood that they will occur because we will have a better understanding of our system. The project investment could avoid large unplanned methane releases, actual costs, and reputational costs by potentially avoiding one of these failures, which has been estimated to cost the Company over $300 million. In addition, the new model will help better quantify the cost of a blowout.
Intangibles	Quality improvement - Implementation of a probabilistic risk model provides quantifiable results that are more reliable, transparent, and understandable, rather than relatively ranked; improving confidence in data and leading to improved decision-making for strategic planning, financial planning, and regulatory oversight.
Intangibles	Waste elimination through potential productivity improvements. A true statistical model may eliminate manual efforts that are necessary to populate and maintain the current excel-based model by pulling from populated databases that are centrally maintained by the data owners instead of a singular person.

Gas T&D Historian

Report Pulled: 11/1/2024 **Item ID: 6757**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias OSIsoft PI Historian, Gas Historian Implementation, GAM Historian

Description The Gas Transmission and Distribution (T&D) Historian project will replace the current historian for Gas T&D, eDNA (a traditional Supervisory Control and Data Acquisition (SCADA) historian product from Schneider Electric), and migrate to the standard OSIsoft PI enterprise historian system. The PI system is a suite of software products that are used to collect, store, view, analyze, and share operational data with system users and subject matter experts.

Portfolio Gas Delivery Systems > Gas Engineering & Supply > IT Projects > IT Projects > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SEI

WORK OBJECTIVES

Problem Statement The historian for Gas Transmission and Distribution resides on a decades old platform and is not the Company's historian standard. Data access is cumbersome, requires multiple tools to access it, and does not provide for the storing, analysis or visualization of operational data in a timely manner with appropriate change management control. With the implementation of smart meters, the Company standardized on the more robust OSIsoft PI historian which is used for: (1) Renewable Generation; (2) Electric T&D; and, (3) Smart Energy. The Gas T&D historian has yet to be migrated to OSISoft PI, and the eDNA gas data has limited accessibility and usability in its current state and is no longer supported by the vendor. In addition, maintaining the older platform along with the new system requires duplicate resources and skills. This project will create a more accessible and centralized data source with better controls that can be leveraged as the system of record.

Objectives The project will add value for both Gas Engineering and Gas Operations organizations within the Company by: (1) informing decision-making based on real-time data; (2) improving real-time situational awareness of Operations personnel for information that does not need to be monitored by Gas Control; (3) improving the ability to respond to abnormal situations that do not require immediate intervention through that direct communication to Operations personnel; (4) providing information for the development of proactive analytics to reduce potential catastrophic events; (5) streamlining data access through visualization and analytics; and (6) reducing the waste of using multiple interfaces to interpret data. From an IT perspective, consolidating to one standard historian platform will result in savings in hardware, software, maintenance, resources and training.

Scope This scope of this project includes: (1) replacing the eDNA Gas T&D historian, a traditional SCADA historian, and migrating to the enterprise historian, OSIsoft PI; (2) developing analytics, visualization and reporting capabilities to support tracking of metrics and making operational decisions; (3) replacing the decades-old Microsoft Access-based custom Daily Gas Reports solution; and (4) retiring the legacy Gas T&D eDNA system (hardware and software).

Alternatives An alternative considered for the project was to upgrade eDNA Gas Historian to the latest version. This option was not selected because it requires a significant investment, and does not meet analytics, reporting, usability and accessibility needs as well as the software owner has announced the "sunset," for this software. Furthermore, the Company standard for historians is OSIsoft PI and maintaining two platforms results in redundant efforts in training, support personnel and technology. The option to replace eDNA with the Company standard OSIsoft PI historian was selected to eliminate duplicate training, support personnel, and technology, and to leverage the more robust data analytic capabilities in the OSIsoft PI tool set. Currently the plan is to implement the Gas T&D Historian with the Gas SCADA Software Solution to eliminate the need to have duplicative historians while the Gas SCADA Software Solution is being implemented. If this project is not completed, an interruption of our operational data reporting capabilities could occur and could result in a non-compliance and could potentially interrupt certain volumetric accounting and billing functions.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
4/15/2024	5/27/2024	6/10/2024	7/15/2024
	In-Service/Go-Live	**Closeout**	
	12/1/2025	12/8/2025	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	$0.733	$0.764	-	-	-	-	-	$1.496
O&M	-	$0.017	$0.492	$0.237	$0.237	$0.220	-	-	$1.203
Total Cost of Ownership	-	$0.750	$1.255	$0.237	$0.237	$0.220	-	-	**$2.699**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	-	$0.119	$0.420	-	-	-	-	-	**$0.540**
Outside Services	-	-	$0.200	-	-	-	-	-	**$0.200**
Business Expense/Overheads	-	$0.044	$0.228	-	-	-	-	-	**$0.271**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.141	$0.141	-	-	-	-	-	**$0.281**
Licenses, Permits & Fees	-	$0.446	-	-	-	-	-	-	**$0.446**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$0.750	$0.988	-	-	-	-	-	**$1.738**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	$(0.051)	$(0.150)	-	-	-	-	**$(0.201)**
	Initial	-	$0.017	$0.492	$0.237	$0.237	$0.220	-	-	**$1.203**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.017	$0.441	$0.087	$0.237	$0.220	-	-	**$1.002**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.733	$0.764	-	-	-	-	-	**$1.496**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.733	$0.764	-	-	-	-	-	**$1.496**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.934

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Gas Distribution System	High	Low	Avoid misstating cost of gas sold reducing company reputation risk. PI provides better controls for daily reporting and analysis, which reduces risk of misstating the cost of gas sold. The financial risk of misstating the cost of gas sold is $3,150,000 a year. This assumes: – Current CMS revenue of $6 billion – Misstated cost of gas sold was $60,000,000 – Misstated cost of gas was > 10% corporate threshold for having to restate financials – 282.5 million stock volume * $44.63 stock price (5/15/2018) – 1% probability of misstatement occurring – 50% probability being required to restate financials – 5% stock price lost (this occurred circa 2001) 282.5 million * $44.63 = $12.6 billion $12.6 billion * 5% = $630,000,000 $630,000,000 * 1% * 50% = $3,150,000
Technology Obsolescence	High	Medium	eDNA is multiple versions behind. The company has been awaiting for funding to transition to the company standard, Pi Historian.

OTHER VALUE

Type	Description
Avoided Costs	$10,000 avoided cost for Distribution System Pressure Exceeds Limit Report with benefit of being able to identify more MAOP exceedance events and be more proactive on the reporting of them, which supports public safety, company reputation, and compliance
Avoided Costs	20 hrs/yr time savings in Calibration Bottle Gas Process. Average of 10 Calibration Bottle Exchanges per year, 3 hrs per Calibration Gas Order. PI software will be need to interface with SAP. Using PI, Gas Measurement Technician (GMT) Specialist would just need to review, approve, and submit the order to the vendor (0.5 hrs), track bottle delivery (negligible), and install (0.5 hrs). - 45 hrs/yr time savings in Carrier (Helium) Bottle Gas Process. Average 90 Carrier Bottle Exchanges per year, 1 hr per Carrier Gas Order. PI software will need to interface with SAP. Using PI, GMT Specialist would just need to review, approve, and submit the order to the vendor (0.25 hrs), track bottle delivery (negligible), and install (0.25 hrs). - 30 hrs/yr time savings in Ultra Sonic Meters (USM) Health Assessment/Repair. Currently GMS Specialist dedicates 5 hrs per USM diagnostic/repair. Average 10 major repairs/yr. PI would be utilized to interface with Daniel Predictive Application as well as SAP for: work order creation & parts supply chain parts ordering. This would reduce GMT Specialist to ~2 hrs for diagnostic/trending/tracking and reduce on-site assessments. - 176 hrs/yr time savings in Fuel Metering Monthly Reporting. Currently GMT Specialist dedicates 200 hrs/yr to the monthly reporting of City Gate and Free Gas Users natural gas usage. Using PI data analytics and reporting, this would be reduced to 24 hrs/yr.
Avoided Costs	78 hrs/yr time savings for importing flow, pressure, and temperature data for pig run preparation, outage preparation, and pig run reporting as well as creating custom tracking sheets using real-time data.
Avoided Costs	Avoid additional Gas Control headcount - Replacing the DGR Database with a more robust PI historian will reduce daily reporting time and effort each month while providing results that are more accurate and available. (2 Gas Controllers * 1 hr/day * 365 days/yr = 730 hrs/yr)
Avoided Costs	Avoided IT Operational Technology Labor when eDNA retired, Savings from consolidating from two supported historian platforms to one: 6 hours per server times 6 servers saved from Critical Infrastructure Systems team, 160 hours saved from the effort that would be required to migrate to the new hardware and upgrading eDNA to the legacy fork of the software, including testing, 500 hours saved from not having to migrate eDNA to the modern architecture (&Step), 300 hours saved from not having to migrate custom (.NET 2.0) interfaces to new version of eDNA (SCADA to eDNA, eDNA to FlowCal, eDNA to Maximum Allowable Operating Pressure (MAOP) data)
Avoided Costs	Avoided Project to move forward to build a replacement for the DGR (Daily Gas Reports) Access Database [$300,000]
Technology Capability	Electric T&D, Gas T&D, Generation
Intangibles	Gas Control - Replacing the Daily Gas Reports Database with a more robust PI historian will enable the ability to remove non-PHMSA mandated monitoring from Gas Control SCADA and enhance public safety through reduction in Odorizer issues.
Avoided Costs	Gas Measeurement Engineering 80 hrs/yr time savings through more efficient data analysis.
Avoided Costs	Total of $46,961, projected cost avoidance from IT work related to CITECH for Non-Code Preventive Maintenance. (Based on 2019 work order data totaling $62,615/yr then reducing that by a total of 75% over three years). Projected future waste reduction in time saved annually by avoiding on site facility visits for equipment issue diagnosing is estimated at 183 hrs/yr ($18,117/yr). (Based on 2017 data which was 244 hrs , $24156/yr and reducing that by 25%). Assuming this to be 75% reduction in time charged (some time is still required for reviewing PI notifications & performing data analysis). Conservatively associating work with IM only. Reduced occurrence of pressure regulation equipment failures. September 2017 incident in Lansing ~ $450,000+. Assuming annual, levelized risk to be $100,000/yr (collateral and regulatory fines) *Assuming an hourly rate of $99/hr.

Gas Transmission Probabilistic Risk Model

Report Pulled: 11/1/2024 **Item ID: 8801**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Gas Transmission Probabilistic Risk Model

Description The project will implement a risk analysis model for comprehensive predictive risk analysis and modeling on gas transmission pipeline assets.

Portfolio Gas Delivery Systems > Gas Engineering & Supply > IT Projects > IT Projects > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-GAS

WORK OBJECTIVES

Problem Statement

Relative risk models are unit-less measures of risk derived from input information using qualitative data and ordinal scales to produce "risk index" scoring; in simple terms, the relative risk model does not provide true statistical measures. The risk assessment used in the current model provides a score for likelihood, consequence, and risk that is relevant only in comparison to other scores. While the outputs provide a sense of relative risk when comparing one pipeline with another, the scores do not provide quantitative scores for probability, frequency, or expected loss of events. Although pipeline operators commonly use relative risk models, the quality of the relative risk ranking relies on subject matter expert inputs, human inferences, and opinions. Furthermore, the current model does not meet the requirements of the MPSC, as indicated in a letter of noncompliance (dated January 15, 2019), citing gaps in the model with respect to known-failure data for welding and fabrication threats, inadequate depth-of cover calculations, level of corrosion, and inability to provide statistical validation. Inability to mitigate these non-compliances without a probabilistic risk model or through significant manual workarounds will likely result in continued non-compliances.

Objectives

Completion of this project will provide value to both the Company and its customers. Each party will benefit from safety improvements and risk mitigation through statistically-based risk modeling that leads to more informed pipeline replacement or improvement projects. Implementing probabilistic risk modelling supports the changes planned for in the Company's Natural Gas Delivery Plan (NGDP), including the Company Gas Management Safety System (GSMS). GSMS incorporates the Company's plan to implement the American Petroleum Institute (API) Recommended Practice 1173 (Pipeline Safety Management Systems). Additionally, the implementation of a probabilistic risk model will: (1) calculate quantitative risk scores that include measures of probability, frequency, or expected loss of events; and (2) configure multiple data sources to make advanced statistical calculations for interacting threats, both of which allow the Company to make more informed decisions based on improved quality inputs in a measurable model; and (3) provide information for better decisions on Capital project improvements and integrity management. Unlike the current unit-less relative model a probabilistic model will be a unit based risk score, specifically in the unit of dollars, improving efficiency in interpreting risk results for business decisions.

Scope

The project scope encompasses the implementation of a probabilistic risk model for gas transmission. The project will: (1) install and configure risk model; (2) configure multiple data sources; and (3) develop reports and dashboards.

Alternatives

Alternatives considered for the project include: (1) Continue the use of the relative risk model, but investing in substantial effort to build customization to bring the model into compliance. This alternative was not selected because although custom workarounds may bring the model into compliance, those work-arounds still result in arbitrary, relative rankings and do not provide confidence in the ability to provide statistical validation of results. (2) Implement a custom, Excel-based probabilistic risk model through a consulting effort. This alternative was not selected because although the effort minimizes the IT cost of the project, the model requires the creation of secondary data sources, leading to multiple "sources of truth". (3) Implement an on-premise probabilistic risk model. This alternative was not selected because the on-premise solutions analyzed are not mature and have not been widely tested with transmission operators. The option of implementing the cloud-based probabilistic risk model was chosen because it is the most cost-effective long-term implementation approach, providing commercial, off-the-shelf capabilities, industry-proven and upgradable technology, and ongoing vendor support.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/3/2021	3/1/2021	9/30/2021	6/24/2022
	In-Service/Go-Live	**Closeout**	
	6/24/2022	7/29/2022	

FUNDING SUMMARY

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Cap+COR	$0.417	$0.470	$0.177	-	-	-	-	-	$1.064
O&M	$0.158	$0.097	$0.003	$0.109	$0.109	$0.109	$0.109	-	$0.694
Total Cost of Ownership	$0.575	$0.567	$0.180	$0.109	$0.109	$0.109	$0.109	-	**$1.758**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.118	$0.015	$0.003	-	-	-	-	-	**$0.137**
Outside Services	$0.446	$0.507	$(0.215)	-	-	-	-	-	**$0.738**
Business Expense/Overheads	$0.011	$0.044	$0.047	-	-	-	-	-	**$0.102**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	$0.345	-	-	-	-	-	**$0.345**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.575	$0.567	$0.180	-	-	-	-	-	**$1.322**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2021	2022	2023	2024	2025	2026	2027	2028 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.158	$0.097	$0.003	$0.109	$0.109	$0.109	$0.109	-	**$0.694**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.158	$0.097	$0.003	$0.109	$0.109	$0.109	$0.109	-	**$0.694**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.417	$0.470	$0.177	-	-	-	-	-	**$1.064**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.417	$0.470	$0.177	-	-	-	-	-	**$1.064**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Asset Management
Avoided Costs	Assumes 800 hours in annual avoided labor due to reduced labor efforts in Gas Engineering & Supply areas for running existing risk models. The new model decreases 20-30 hours of data management and analysis per transmission asset line, and assumes about 25-40 lines per year. The relative risk model utilizes large sets of data that are not consumed by any other company stakeholders. These are scoring-based data sets that are updated every time there is a change to the pipeline and periodically throughout the year. It is estimated that approximately 800 hours a year are spent updating these data sets, which can be avoided after the new model is implemented.
Risk Mitigation	Implementation of a probabilistic risk model mitigates risk through a comprehensive, statistical analysis of threats to pipe segments, ensuring focus on solving the right problems and resolving the highest risk items.
Risk Mitigation	Prevention of pipeline failures and voided cost of pipeline ruptures: A probabilistic risk model would increase our ability to identify potential failures before they occur. A failure such as a pipe rupture can have a significant impact on the company, including the dollar cost to repair the damage as well as the impact to the public's perception of the Company. It is anticipated that there will be a reduction in these types of failures with this improved tool. Although the model will not necessarily eliminate the possibility that these types of ruptures will occur in the future, the model will reduce the likelihood that they will occur because we will have a better understanding of our system. The project investment could avoid actual and reputational costs by potentially avoiding one of these failures, which has been estimated to cost CE up to $160 million. In addition, the new model will help better quantify the cost of a rupture.
Intangibles	Quality improvement - Implementation of a probabilistic risk model provides quantifiable results that are more reliable, transparent, and understandable, rather than relatively ranked; improving confidence in data and leading to improved decision-making for strategic planning, financial planning, and regulatory oversight.
Intangibles	Waste elimination through potential productivity improvements. A true statistical model may eliminate workarounds with the current model that are necessary to support planning efforts by reducing investigation time and increasing user expertise through quantitative analysis and insight to core model functionality.

Genesys Cloud Migration

Report Pulled: 11/1/2024 **Item ID: 13423**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias , Genesys Cloud Migration

Description The project will migrate the Company's existing on-premise customer contact solution and deploy it to the Genesys Platform As A Service ("PAAS") cloud-based solution. It will provide the Company with the ability to reduce operational costs for performing upgrades and maintenance, take advantage of new enhancements offered by the vendor, and ensure continued support of a critical customer communication channel.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement In 2028, standard vendor support ends for the current on-premise software and extended support is not available from the vendor. Without vendor support, the application no longer receives security patches, bug fixes, or functionality support from the vendor, which creates security, stability, and reliability risk. With the upcoming end of standard support, the vendor is no longer offering feature enhancements to the current on-premise solution limiting the Company's ability to invest in new ways to better serve its customers.

Objectives This project will provide value to both the Company and its customers through: (1) reducing costs with cloud allocated hardware scalable to current usage needs; (2) reducing operating costs with vendor managed feature updates and maintenance provided without service disruption; (3) providing access to new and innovative capabilities to enhance customer service; and (4) reducing security, stability, and performance risk by ensuring consistent, seamless vendor support.

Scope The project scope includes: (1) deploying the new PAAS cloud-based solution in the vendor cloud environment; (2) installing a new internet circuit to directly connect the Company's systems to the vendors cloud environment; (3) updating existing customer interactive voice response ("IVR") system to accommodate the new cloud implementation; (4) implement new features supporting analytics, quality, and reporting; and (5) implement a built-in customer survey tool.

Alternatives Alternatives considered include: (1) Defer to later years. This alternative was not selected due to requiring upgrades of existing on-premise hardware, impeding our ability to take advantage of new features offered by the cloud solution, and reducing cost savings opportunities presented by moving to the cloud. (2) Deploy Genesys on-premise solution to new on-premise hardware. This alternative was not selected due cost associated with purchasing new hardware and does not address the security, stability, and reliability risk resulting from the vendor end of support for the on-premise software. (3) Select and migrate to a new vendor software. This alternative was not selected due to the complexity of our existing internal integrations between the Genesys platform and the Company's other internal systems. As a result, selecting a new system with a new vendor would make the switch cost prohibitive. (4) Migrate to the Genesys Cloud platform. This alternative was selected due to it building on the Company strategy of moving to cloud, reducing operating and maintenance costs, and reduces risk by ensuring consistent, seamless vendor support.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
3/1/2024	6/1/2024	8/1/2024	2/10/2025
	In-Service/Go-Live	**Closeout**	
	9/11/2025	9/26/2025	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.237	$1.855	$2.289	$2.364	$2.000	$0.063	-	-	$8.808
Total Cost of Ownership	$0.237	$1.855	$2.289	$2.364	$2.000	$0.063	-	-	**$8.808**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.008	$0.290	$0.400	$0.400	$0.200	-	-	-	**$1.298**
Outside Services	$0.229	$0.218	$0.301	$0.301	$0.150	-	-	-	**$1.199**
Business Expense/Overheads	$0.000	$0.020	$0.028	$0.028	$0.014	-	-	-	**$0.091**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$1.264	$1.497	$1.572	$1.572	-	-	-	**$5.906**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.237	$1.792	$2.226	$2.301	$1.937	-	-	-	**$8.493**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	$(0.597)	$(0.378)	$(0.303)	$(0.303)	$(0.153)	-	-	**$(1.736)**
	Initial	$0.237	$1.855	$2.289	$2.364	$2.000	$0.063	-	-	**$8.808**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.237	$1.258	$1.911	$2.061	$1.696	$(0.090)	-	-	**$7.073**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.802

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Avoided costs of $1,000,000 associated with on-premise server upgrades which would require both internal and external labor to complete. Savings based on on-prem server upgrades estimated at a total of $970,000 and $30,000 in extended server support would not be needed for the year 2026.
Avoided Costs	Avoided costs of $2,669,170 associated with the Genesys indication of a 20% increase in on-premise software maintenance year over year until the on-premise end-of-life. Calculated by taking the difference between the IT forecasted on-premises software maintenance minus the estimated expected cost with 20% increase for each year starting in 2025. [2025: $1,717,174 (expected) - $1,623,397 (forecast) = $93,777] [2026: $2,060,608 (expected) - $1,638,077 (forecast) = $422,531] [2027: $2,472,730 (expected) - $1,638,077 (forecast) = $834,653] [2028: $2,967,286 (expected) - $1,638,077 (forecast) = $1,329,209] [Total Savings: $93,777 + $422,531 + $834,653 + $1,329,209 = $2,669,170]
Avoided Costs	Avoided costs of $365,000 associated with reduction of voice circuits. Savings based on $60,000 per year in SIP circuit costs + $60,000 per year in H&H voice circuit costs, minus $63,000 in annual costs for AWS direct connect. Assumes only partial year costs for AWS ciruict in 2024. [2024: $120,000 - $40,000 = $80,000] [2025: $120,000 - $63,000 = $57,000] [2026: $120,000 - $63,000 = $57,000] [2027: $120,000 - $63,000 = $57,000] [2028: $120,000 - $63,000 = $57,000] [2029: $120,000 - $63,000 = $57,000] [Total Savings = $80,000 + $57,000 + $57,000 + $57,000 + $57,000 + $57,000 + $57,000 = $365,000]
Avoided Costs	Reduces annual ongoing costs associated with running on-premise solution including virtual machines and storage. Approximate avoided cost of $728,092 per year which was estimated by including the monthly HCL management expense per virtual machine, Azure 3rd copy backup storage, VMware licenses, on-premise Commvault backup storage, operating system licenses, and other shared infrastructure costs.

HR Support Pack and Business Software Inc Upgrade 2023 — Report Pulled: 11/1/2024 — Item ID: 12506

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - Interval — **Work Type** Project

Alias , HR Support Pack and Business Software Inc Upgrade 2023

Description The HR Support Pack and BSI upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T — **Bus Unit** INFORMATION TECHNOLOGY — **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll.

Objectives This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll.

Scope The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company.

Alternatives As this is an upgrade of an existing system, the alternative considered was to delay the upgrade. This alternative was not chosen due to the risk of not complying with financial rules and regulations.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/6/2023	2/27/2023	4/3/2023	4/24/2023
	In-Service/Go-Live	**Closeout**	
	12/22/2023	12/29/2023	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.647	$0.017	-	-	-	-	-	-	$0.664
Total Cost of Ownership	$0.647	$0.017	-	-	-	-	-	-	**$0.664**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.079	$0.002	-	-	-	-	-	-	**$0.081**
Outside Services	$0.528	$0.014	-	-	-	-	-	-	**$0.542**
Business Expense/Overheads	$0.040	$0.001	-	-	-	-	-	-	**$0.041**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.001	-	-	-	-	-	-	-	**$0.001**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.647	$0.017	-	-	-	-	-	-	**$0.664**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.647	$0.017	-	-	-	-	-	-	**$0.664**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.647	$0.017	-	-	-	-	-	-	**$0.664**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Compliance & Ethics	High	High	Without the release of the new support packs from SAP, Consumers Energy would not be compliant with new HR and tax changes. As a result, it would not be able to calculate and distribute payroll.

OTHER VALUE

Type	Description
Technology Capability	Compliance & Risk Management
Risk Mitigation	The support packs are released throughout the course of the year to ensure compliance with HR and tax changes.

HR Support Pack and Business Software Inc Upgrade 2024

Report Pulled: 11/1/2024 **Item ID: 12507**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - Interval **Work Type** Project

Alias , HR Support Pack and Business Software Inc Upgrade 2024

Description The HR Support Pack and BSI upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll.

Objectives This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll.

Scope The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company.

Alternatives As this is an upgrade of an existing system, the alternative considered was to delay the upgrade. This alternative was not chosen due to the risk of not complying with financial rules and regulations.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/5/2024	3/1/2024	4/1/2024	11/1/2024
	In-Service/Go-Live	**Closeout**	
	12/21/2024	12/31/2024	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	-	-	$0.569	-	-	-	-	-	$0.569
Total Cost of Ownership	-	-	$0.569	-	-	-	-	-	**$0.569**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	-	-	$0.118	-	-	-	-	-	**$0.118**
Outside Services	-	-	$0.434	-	-	-	-	-	**$0.434**
Business Expense/Overheads	-	-	$0.017	-	-	-	-	-	**$0.017**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	-	-	$0.569	-	-	-	-	-	**$0.569**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	$0.569	-	-	-	-	-	**$0.569**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	$0.569	-	-	-	-	-	**$0.569**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Compliance & Ethics	High	High	Without the release of the new support packs from SAP, Consumers Energy would not be compliant with new HR and tax changes. As a result, it would not be able to calculate and distribute payroll.

OTHER VALUE

Type	Description
Technology Capability	Compliance & Risk Management
Risk Mitigation	The support packs are released throughout the course of the year to ensure compliance with HR and tax changes.

HR Support Pack and Business Software Inc Upgrade 2025

Report Pulled: 11/1/2024 **Item ID: 12508**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - Interval **Work Type** Project

Alias , HR Support Pack and Business Software Inc Upgrade 2025

Description The HR Support Pack and BSI upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SEI

WORK OBJECTIVES

Problem Statement SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll.

Objectives This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll.

Scope The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company.

Alternatives Alternatives considered include: (1) Not upgrading to the current support packs which results in noncompliance with financial rules and regulations and inaccurate payroll; (2) there is no economical cloud solution, so this option was not entertained; (3) apply the appropriate support pack upgrades. Option (3) is the preferred option because it enables the company to comply with HR and tax changes, resulting in the ability to correctly calculate and distribute payroll.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/5/2025	2/26/2025	3/31/2025	11/1/2025
	In-Service/Go-Live	**Closeout**	
	12/19/2025	12/31/2025	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	-	-	-	$0.984	-	-	-	-	$0.984
Total Cost of Ownership	-	-	-	$0.984	-	-	-	-	**$0.984**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	-	-	-	$0.106	-	-	-	-	**$0.106**
Outside Services	-	-	-	$0.553	-	-	-	-	**$0.553**
Business Expense/Overheads	-	-	-	$0.324	-	-	-	-	**$0.324**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	-	-	$0.984	-	-	-	-	**$0.984**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	$0.984	-	-	-	-	**$0.984**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	$0.984	-	-	-	-	**$0.984**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Compliance & Ethics	High	High	Without the release of the new support packs from SAP, Consumers Energy would not be compliant with new HR and tax changes. As a result, it would not be able to calculate and distribute payroll.

OTHER VALUE

Type	Description
Technology Capability	Compliance & Risk Management
Risk Mitigation	The support packs are released throughout the course of the year to ensure compliance with HR and tax changes.

HR Support Pack and Business Software Inc Upgrade 2026 — Report Pulled: 11/1/2024 — Item ID: 12755

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - Interval — **Work Type** Project

Alias , HR Support Pack and Business Software Inc Upgrade 2025, HR Support Pack and Business Software Inc Upgrade 2026

Description The Human Resources (HR) Support Pack and Business Software Inc (BSI) upgrade will update the SAP system with HR Support Packs that are released annually by SAP to comply with HR and tax changes.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T — **Bus Unit** INFORMATION TECHNOLOGY — **Dept** CX&T-IT-APPLICATION PLATFORMS & SEF

WORK OBJECTIVES

Problem Statement SAP releases annual HR support packs to ensure compliance. Without them, the Company would be unable to comply with HR and tax changes, resulting in the inability to calculate and distribute payroll.

Objectives This project creates value for the Company by: (1) ensuring that its systems are in compliance with new financial rules and regulations; and (2) ensuring that it can calculate and distribute payroll.

Scope The scope of this project is to add SAP HR corrections to ensure proper reporting of financial information by the Company.

Alternatives Alternatives considered include: (1) Not upgrading to the current support packs which results in noncompliance with financial rules and regulations and inaccurate payroll; (2) there is no economical cloud solution, so this option was not entertained; (3) apply the appropriate support pack upgrades. Option (3) is the preferred option because it enables the company to comply with HR and tax changes, resulting in the ability to correctly calculate and distribute payroll.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/5/2026	2/26/2026	3/31/2026	11/1/2026
	In-Service/Go-Live	**Closeout**	
	12/19/2026	12/31/2026	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.785	-	-	-	-	-	-	-	$0.785
Total Cost of Ownership	$0.785	-	-	-	-	-	-	-	**$0.785**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.106	-	-	-	-	-	-	-	**$0.106**
Outside Services	$0.553	-	-	-	-	-	-	-	**$0.553**
Business Expense/Overheads	$0.125	-	-	-	-	-	-	-	**$0.125**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.785	-	-	-	-	-	-	-	**$0.785**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.785	-	-	-	-	-	-	-	**$0.785**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.785	-	-	-	-	-	-	-	**$0.785**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Compliance & Ethics	High	High	Without the release of the new support packs from SAP, Consumers Energy would not be compliant with new HR and tax changes. As a result, it would not be able to calculate and distribute payroll.

OTHER VALUE

Type	Description
Technology Capability	Compliance & Risk Management
Risk Mitigation	The support packs are released throughout the course of the year to ensure compliance with HR and tax changes.

ISIS Papyrus 2026 Upgrade

Report Pulled: 11/1/2024 **Item ID: 13461**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias ISIS Papyrus Upgrade, ISIS Papyrus 2026 Upgrade

Description This project will upgrade the Papyrus Objects suite of applications to the most recent version available per vendor recommendation. The ISIS Papyrus application is critical to creating electronic and paper correspondence for customers, including bills and dunnings.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement The application will be at least 1 major upgrade revision behind by 2026. It's imperative our customers retain unfettered access to their paper bills, dunning notices and other communications produced by ISIS. ISIS also makes customer bills available for online viewing through the website and mobile apps. Without the upgrade, our vendors make no guarantee that any substantial patches or hot fixes impacting application reliability, capacity and security will be forthcoming. The upgrade will address these problems and challenges, as well bring ensure all other platform components comply with our company operational and security standards.

Objectives The value of this project includes: (1) providing a more stable operational model by upgrading to the most recent version available; (2) maintaining the necessary vendor support; and (3) resolving tuning and stability issues with the vendors.

Scope The scope of the project is to upgrade the various licensed products that comprise the Papyrus Objects suite of applications.

Alternatives As this is an upgrade of an existing system, the alternative considered was to delay the upgrade and continue operating with the current version. This alternative was not chosen due to the risk of application stability and the inability to maintain cyber security patching.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2026	2/1/2026	4/1/2026	6/1/2026
	In-Service/Go-Live	**Closeout**	
	9/1/2026	10/1/2026	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	$0.720	-	-	-	-	-	-	-	$0.720
O&M	$0.276	-	-	-	-	-	-	-	$0.276
Total Cost of Ownership	$0.996	-	-	-	-	-	-	-	**$0.996**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.475	-	-	-	-	-	-	-	**$0.475**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.146	-	-	-	-	-	-	-	**$0.146**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.080	-	-	-	-	-	-	-	**$0.080**
Licenses, Permits & Fees	$0.295	-	-	-	-	-	-	-	**$0.295**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.996	-	-	-	-	-	-	-	**$0.996**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.276	-	-	-	-	-	-	-	**$0.276**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.276	-	-	-	-	-	-	-	**$0.276**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.720	-	-	-	-	-	-	-	**$0.720**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.720	-	-	-	-	-	-	-	**$0.720**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	Medium	An out-of-support version of Papyrus Designer means that ISIS Papyrus no longer provides hotfix support. This will put the company network at risk, which is critical to avoid as this is responsible for paper billing.

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Newer versions of ISIS Papyrus enable better integration with newest operating systems (Linux) and database (SQL).
Intangibles	Newer versions of ISIS Papyrus will improve performance and enhance productivity for billing and invoices.

IT Access Controls Governance

Report Pulled: 11/1/2024 **Item ID: 6830**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - Interval **Work Type** Project

Alias SAP Access Controls, Access Controls Governance, IT Access Controls Governance

Description This project replaces the current software tool that manages and monitors Sarbanes-Oxley Act ("SOX") compliance for SAP transactions.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-PLANNING & GOV

WORK OBJECTIVES

Problem Statement

To comply with SOX controls, standard SAP user access is reviewed on a semi-annual schedule, sensitive access is reviewed quarterly, and emergency access management is reviewed as needed. The current solution for validating these controls is SAP's GRC (Governance, Risk and Compliance) Access Controls software application. The SAP GRC system is the backstop for the Company's IT General Controls, which ensures legal compliance. Problems with current implementation include: (1) increased risks as the current process is manually intensive and inefficient, and could lead to SOX audit deficiencies; (2) customized code makes it difficult and costly to maintain, including the application of fixes; (3) difficulty meeting SOX compliance when requirements change from auditors and the Public Company Accounting Oversight Board (PCAOB); (4) incomplete reports for segregation of duties and change logs; and (5) increased risks exist when elevated access is needed in SAP production.

Objectives

The project will add value through: (1) reducing risk and eliminating waste through new tools that provide higher levels of automation and process optimization to reduce inefficiencies, human errors and avoid SOX audit findings; (2) decreasing maintenance of $15,000 per month and upgrade costs by implementing an out-of-the-box solution without customization; (3) increasing the ability to meet requirement changes from auditors and the Public Company Accounting Oversight Board; and (4) creating complete and accurate report capabilities.

Scope

The project scope includes: (1) automating the SAP periodic user access review; (2) automating the emergency access management process; (3) displaying areas of risk and identifying how to mediate that risk; (4) tracking mitigations; and (5) converting the current rule set into the new tool.

Alternatives

Alternatives considered include: (1) Continue using the current application as-is, accepting the audit risks stemming from known issues. This alternative was not selected due to the risk associated withstandard SAP support ending on December 31, 2020. (2) Use robotic process automation in a limited scope to automate some manual tasks and reduce errors. This alternative was not selected as it would not mitigate risks and gaps in the current tool. (3) Develop a custom solution to perform some of the work. This alternative was not selected as it would be more costly and include higher maintenance and support costs. (4) Continue applying program patches and fixes from SAP for the current tool. This alternative was not selected as it does not address or fulfill all requirements, and requires support from an external vendor, which increases support costs. (5) Replace the existing tool with a new solution. This alternative was selected as it meets Company requirements, avoids hiring two additional resources, is more cost effective in the long term, adds more process automation, and increases SOX compliance.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/7/2021	4/30/2021	7/31/2021	10/28/2021
	In-Service/Go-Live	**Closeout**	
	10/29/2021	12/18/2021	

FUNDING SUMMARY

	2020	2021	2022	2023	2024	2025	2026	2027 +	Total
Cap+COR	$0.586	$1.428	$1.357	$0.322	-	-	-	-	$3.693
O&M	$0.163	$0.366	$0.116	$0.130	$0.177	$0.182	$0.188	$0.190	$1.512
Total Cost of Ownership	$0.749	$1.794	$1.473	$0.451	$0.177	$0.182	$0.188	$0.190	**$5.205**

	2020	2021	2022	2023	2024	2025	2026	2027 +	Total
Labor	-	$0.440	$0.083	-	-	-	-	-	**$0.523**
Outside Services	$0.071	$0.980	$1.276	-	-	-	-	-	**$2.327**
Business Expense/Overheads	$0.014	$0.105	$(0.463)	-	-	-	-	-	**$(0.344)**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.028	-	$0.066	-	-	-	-	**$0.094**
Licenses, Permits & Fees	$0.664	$0.241	$0.577	$0.322	-	-	-	-	**$1.804**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.749	$1.794	$1.473	$0.388	-	-	-	-	**$4.404**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2020	2021	2022	2023	2024	2025	2026	2027 +	Total
O&M	Reduction	-	-	$(0.108)	$(0.108)	$(0.108)	$(0.108)	$(0.108)	-	**$(0.540)**
	Initial	$0.163	$0.366	$0.116	$0.130	$0.177	$0.182	$0.188	$0.190	**$1.512**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.163	$0.366	$0.008	$0.022	$0.069	$0.074	$0.080	$0.190	**$0.972**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.586	$1.428	$1.357	$0.322	-	-	-	-	**$3.693**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.586	$1.428	$1.357	$0.322	-	-	-	-	**$3.693**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.920

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Material Weakness in Business Controls	High	Low	This project will help ensure we do not have a material weakness.

OTHER VALUE

Type	Description
Technology Capability	Compliance & Risk Management
Risk Mitigation	Elimination of manual processes which are inefficient, prone to errors and could lead to SOX audit findings or material weaknesses.
Intangibles	If this project is not done, IT Corporate Services will need to hire two additional resources to manage sensitive access and segregation of duties risk management.

IT Operations Management - Service Operations

Report Pulled: 11/1/2024 **Item ID: 13929**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , IT Operations Management - Service Operations

Description This project will implement an application service mapping tool to effectively manage business-critical services through identification of infrastructure components and application interactions. This tool automates the mapping process to create a complete, up-to-date, and accurate record of the mapped application service in the Database. Application service mapping works hand-in-hand with asset discovery, building on discovered infrastructure data to identify all the assets that support a service, and along with their service-specific relationships.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement As the IT systems steadily increases in complexity and evolve faster than the IT organization can respond to system issues in an optimized and cost-effective manner, the current configuration of the system does not provide the clarity needed in order to understand how the infrastructure interacts with the applications within the IT System it supports and in order to respond to emergent IT incidents in the most rapid and costs effective manner. These constraints can lead to lengthy response and implementation times; negligible or ineffective resolutions; reduced functionality; and elongated outage times in the infrastructure and applications in the system.

Objectives This project will create value for the Company by mapping critical application services through discovery of the underlying infrastructure associated with application services and its relationship to parent business applications. Specifically, by creating application service maps, this project will: (1) increase visibility and understanding between Information Technology (IT) infrastructure and Configuration Items; (2) improve accuracy through real-time, automatically updated infrastructure and component changes; (3) reduce IT Subject Matter Experts time on emergent IT issues; (4) Utilize of IT Service Management processes; and (5) Reduce downtime by identifying dependences and impact analysis.

Scope The project scope includes: (1) implementation of On-Premise application service maps which have significant business impact; (2) establishment of process roles needed to support service maps built.

Alternatives Alternatives considered included: (1) Choose an alternate IT Operations Management System with Cloud capabilities. This alternative was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. This alternative was not chosen as there would be a correlation gap between application services and the underlying infrastructure and would not address the ever-increasing resolution costs. (4) Develop and implement an on-premises service mapping and process solution. This alternative was chosen due to the value in Information Technology (IT) Operations Management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can utilize the Configuration Management Database (CMDB) and work hand-in-hand with asset discovery.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
10/1/2023	12/1/2023	12/31/2023	1/1/2024
	In-Service/Go-Live	**Closeout**	
	3/9/2024	3/30/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$2.812	$0.200	-	-	-	-	-	-	$3.012
O&M	$0.634	$0.066	$0.015	$0.015	$0.015	$0.015	-	-	$0.760
Total Cost of Ownership	$3.446	$0.266	$0.015	$0.015	$0.015	$0.015	-	-	**$3.772**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.002	$0.004	-	-	-	-	-	-	**$0.006**
Outside Services	$0.074	$0.202	-	-	-	-	-	-	**$0.276**
Business Expense/Overheads	$0.028	$0.059	-	-	-	-	-	-	**$0.087**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$3.342	-	-	-	-	-	-	-	**$3.342**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$3.446	$0.266	-	-	-	-	-	-	**$3.712**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.634	$0.066	$0.015	$0.015	$0.015	$0.015	-	-	**$0.760**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.634	$0.066	$0.015	$0.015	$0.015	$0.015	-	-	**$0.760**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.812	$0.200	-	-	-	-	-	-	**$3.012**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.812	$0.200	-	-	-	-	-	-	**$3.012**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	By implementing ITOM application service mapping it enables the Top-Down Service aware CMDB that can utilize Information Technology Service Management processes and helps in quicker Business Impact determination which will help prioritize the actions and decisions for future enhancements.
Technology Capability	By implementing ITOM Application Service Mapping there will be better Administrative & General (A&G) Support, as this provides visibility into how the infrastructure is connected to applications. It will create a more Service aware configuration management which will improve technical impact Analysis and prioritization leading to a reduction in downtime, better root cause analysis of incidents for the operations teams, and efficient change management.
Avoided Costs	Improving the MTTR (Mean Time to Resolution) for major incidents is one of the primary uses for having services mapped. Understanding the relationships between all of the CIs that make up a service, and easily seeing recent Incidents and Changes on those CIs, provides invaluable insight in both ensuring the Incident is routed to the right team quickly, and in troubleshooting an active issue. Projected Cost Saving - 30% of total labor cost - about $420K on Non-MI MTTR (Customer impacting P2 incidents - Performance/Degradation) and $360K on MI MTTR (P1 and P2 Critical incidents).
Technology Capability	Service Mapping makes the IT process more reliable with Automated mapping services that reduces the time users are handling errors and also enabling the mapping to be updated in real time.

Itron Enterprise Edition 2025 Upgrade

Report Pulled: 11/1/2024 **Item ID: 11761**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias Itron Enterprise Edition Upgrade, Itron Enterprise Edition 2025 Upgrade, Itron Enterprise Edition 2024 Upgrade, Itron Enterprise Edition 2026 Upgrade, Itron Enterprise Edition 2025 Upgrade

Description This project will upgrade Itron Enterprise Edition (IEE), which collects the reads from meters to ensure non-estimated bill accuracy.

Portfolio IT Services > Applications > Foundational Enterprise Applications > Foundational Enterprise Applications > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement Itron Enterprise Edition (IEE) is the Company's keystone application of the Advanced Metering Infrastructure (AMI), that provides billing data that includes time of use data. If this application does not stay current, the Company increases the risk business operations could be interrupted or compromised. Itron Enterprise Edition (IEE) is a key component in keeping the Company current, with billing capacity, stability, and accuracy obligations.

Objectives This project creates value for the Company by: (1) ensuring the features and functionality needed to meet and exceed customer satisfaction and billing accuracy are available to business partners and IT; (2) meeting Information Security's requirement to keep applications patched and protected from cyber attack.

Scope The scope of this project includes: (1) upgrading the Itron Enterprise Edition (IEE) applications to the next appropriate versions; (2) migrating the database to the next version required by the application.

Alternatives Alternatives considered included: (1) Defer the upgrade. This alternative was not selected because it would decouple Itron IEE (CE's Meter Data Management) from the Itron security infrastructure introducing application instability, security and dependency risks to the utility, possibly negatively impacting critical customer electric and gas billing operations. It would also likely affect other business critical Itron applications use, creating more expense to support and no ability to leverage updated tool capability. (2) Replace the platform. Replacing IEE/MDM would require the application business owners to undertake a new initiative mirroring the expense and effort that went into the multi-million dollar project responsible for setting up and leveraging this utility. (3) Perform the upgrade. This option is superior for both our customers and our Company because it maintains vendor support for hot fixes and patches, and aligns with all upgrade projects related to other Itron products.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
7/29/2025	8/12/2025	10/24/2025	5/1/2026
	In-Service/Go-Live	**Closeout**	
	5/20/2026	6/9/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.248	$0.248	-	-	-	-	-	-	$0.495
Total Cost of Ownership	$0.248	$0.248	-	-	-	-	-	-	**$0.495**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.231	$0.231	-	-	-	-	-	-	**$0.463**
Outside Services	-	-	-	-	-	-	-	-	**-**
Business Expense/Overheads	$0.016	$0.016	-	-	-	-	-	-	**$0.032**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$0.248	$0.248	-	-	-	-	-	-	**$0.495**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.248	$0.248	-	-	-	-	-	-	**$0.495**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.248	$0.248	-	-	-	-	-	-	**$0.495**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	High	If Consumers Energy does not upgrade this equipment, it would run the risk of losing support from the vendor, leading to security vulnerabilities and operational efficiency issues.

OTHER VALUE

Type	Description
Technology Capability	Technology Capability
Risk Mitigation	Without the upgrade, supportability and operational efficiency issues may increase over time. Resolving these issues becomes very problematic if vendor support is not available. It would also be difficult to keep the system current with security updates.

Next Generation electronic Shift Operations Management Sys Report Pulled: 11/1/2024 Item ID: 12483

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Next Generation Clearance Management, Next Generation electronic Shift Operations Management System Replacement, Next Generation electronic Shift Operations Management System (eSOMS) Replacement

Description The project replaces the eSOMS with updated clearance lock out tag out ("LOTO") management software for Electric Generation facilities, and narrative logs and mobile rounds functionality for Electric Generation and Gas Compression facilities.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement The vendor is replacing the current system used at the Company and other utilities with a new software package called Lumada. The software migration is necessary for the Company to retain vendor support, so that the databases continue to receive security patches, bug fixes, and functionality support from the vendor, and avoid security, stability, and reliability risk.

Objectives The project will add value by: (1) maintaining functionality of a critical life safety application; (2) reducing the human struggle that comes from manual workarounds and an older application; (3) empowering employees with proper electronic tools to meet customer expectations; (4) enabling process improvements to deliver outages more effectively; (5) reducing plant downtime; (6) increasing reliability; and (7) increasing standardization across the Company.

Scope The scope of this project includes: (1) configuring software for clearance management, logbook, rounds, automated emails, and reporting; (2) migrating and archiving data; (3) enabling additional offline capabilities, (4) integrating with SAP for equipment and current status of work orders; (5) adding new integration to SAP for notifications from rounds and clearance functions (6) testing the software, data migrations and integrations; and (7) updating configuration management database, runbook, system recovery plan, LOTO work procedure, qualification training and other standard documentation.

Alternatives Alternatives considered include: (1) continuing to use the eSOMS application, though without vendor support. This alternative was not selected because losing vendor support for this critical application increases risks for application security, reliability, and supportability that can result in an employee safety incident in the complex tagging process, an extended plant production outage, a prolonged plant reliability issue, or regulatory or compliance violations. (2) Instituting the manual business continuity process until the application replacement is possible. This alternative was not selected because it would also increase the previously mentioned operational risks. (3) Replacing the eSOMS application by customizing SAP. This alternative was not selected as it would be more expensive and introduce additional risk to employees due to poor application fit. (4) Migrating the existing eSOMS data to an out the box application such as the Lumada application. The option to migrate the existing eSOMS application to an out of the box solution was chosen to minimize cost and risk to the Company and its employees. Cloud hosting of the application infrastructure at the vendor's location was also evaluated, though due to the greater cost of this vendor hosting, the application infrastructure will be hosted on premise at the Company.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/19/2026	3/13/2026	6/19/2026	2/25/2027
	In-Service/Go-Live	**Closeout**	
	2/25/2027	3/26/2027	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	$0.600	$0.312	-	-	-	-	-	-	$0.913
O&M	$0.027	$0.019	-	-	-	-	-	-	$0.046
Total Cost of Ownership	$0.627	$0.331	-	-	-	-	-	-	**$0.958**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.294	$0.162	-	-	-	-	-	-	**$0.455**
Outside Services	$0.160	$0.073	-	-	-	-	-	-	**$0.233**
Business Expense/Overheads	$0.151	$0.094	-	-	-	-	-	-	**$0.245**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.022	$0.003	-	-	-	-	-	-	**$0.024**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.627	$0.331	-	-	-	-	-	-	**$0.958**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.027	$0.019	-	-	-	-	-	-	**$0.046**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.027	$0.019	-	-	-	-	-	-	**$0.046**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.600	$0.312	-	-	-	-	-	-	**$0.913**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.600	$0.312	-	-	-	-	-	-	**$0.913**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	4 - Electric T&D, Gas T&D, Generation
Intangibles	Having this electronic application available through a vendor supported version, empowers employees with proper electronic tools instead of requiring paper logging, switching and tagging and rounds processes.
Intangibles	The new software offers functionality improvements to better support plant outages (switching and tagging), logging, mobile and other functions more effectively.
Intangibles	The new software reduces the human struggle of using manual workarounds for known issues in the current application's connectivity requirements.
Risk Mitigation	This is a life safety application, therefore the risk of not keeping the application functioning risks the safety of Generation Operations' employees and contractors. If Consumers Energy uses an unsupported version and risks a critical application issue, it may result in a potential safety incident, prolonged plant production outage, prolonged plant reliability issue, regulatory or compliance violation.

Operational Technology - Service Management Upgrade

Report Pulled: 11/1/2024 **Item ID: 13924**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , ServiceNow OT Module, Operational Technology - Service Management, Operational Technology - Service Management Upgrade

Description This project will implement Operational Technology ("OT") service management capabilities. Service management provides automated asset tracking, maintenance, and incident management for the assets.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement The Company' Internal Audit team conducted an audit of the Operational Technology (OT) asset environment and identified significant gaps in the patch management program. The patch management operating model is decentralized, has limited and inconsistent standards, doesn't have a company-wide governance structure to monitor all business areas of the Company and lacks a complete and accurate asset inventory. Due to the lack of a complete asset inventory, as well as a significant number of gaps identified in the patch management governance, operating model, processes, and controls to manage all assets within the Company's environment, an unknown magnitude of risk exists that critical patches were not installed timely, which could create the potential for increased security vulnerabilities.

Objectives The project provides value to the Company in three ways 1.) Establishes a complete and accurate asset inventory. 2.) Creates a Company-wide governance structure with documented standards and processes to manage the assets and 3.) Defines a comprehensive patch management operating model with clearly defined roles and responsibilities.

Scope The project scope includes: (1) the implementation of an asset management tool (2) the implementation of an incident management tool, (3) and the establishment of process roles needed to support the assets.

Alternatives Alternatives considered included: (1) Choose a Cloud-based alternate asset management system. This option was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. Continue to manually track or not track Operational Technology (OT) Digital assets at the Company, which will not address the need to effectively track OT Digital assets and plan for their support. (4) Develop and implement an asset management and incident management tool and processes. This alternative ultimately chosen has strengths in Information Technology (IT) service management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can help bridge the gap between IT and OT, enable the Company to manage both types of assets through a single interface.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
10/1/2023	11/4/2023	12/1/2023	12/3/2023
	In-Service/Go-Live	**Closeout**	
	3/7/2024	3/29/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.729	$0.164	-	-	-	-	-	-	$0.892
O&M	$0.148	$0.044	$0.005	$0.005	$0.005	$0.005	-	-	$0.212
Total Cost of Ownership	$0.877	$0.208	$0.005	$0.005	$0.005	$0.005	-	-	**$1.105**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.026	$0.035	-	-	-	-	-	-	**$0.062**
Outside Services	$0.039	$0.121	-	-	-	-	-	-	**$0.160**
Business Expense/Overheads	$0.009	$0.051	-	-	-	-	-	-	**$0.061**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.803	-	-	-	-	-	-	-	**$0.803**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.877	$0.208	-	-	-	-	-	-	**$1.085**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.148	$0.044	$0.005	$0.005	$0.005	$0.005	-	-	**$0.212**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.148	$0.044	$0.005	$0.005	$0.005	$0.005	-	-	**$0.212**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.729	$0.164	-	-	-	-	-	-	**$0.892**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.729	$0.164	-	-	-	-	-	-	**$0.892**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Consolidating Operational Technology Assets into a single database establishes the groundwork for potential future service management capabilities such as incident management, change management, and vulnerability management for the Operational Technology Team, all of which are poised to enhance operational performance.
Intangibles	Having Operational Technology Assets in one database will improve efficiencies (with data stored in a single system, resources spend less time searching for information across multiple platforms, leading to increased productivity and faster decision making), increase accuracy (centralizing data reduces the likelihood of errors and inconsistencies that can occur when information is spread across disparate systems), better collaboration (one system encourages collaboration across teams. This fosters teamwork and enhances communication within the organization), better insights (having data in a single database facilitates comprehensive analysis and reporting. This allows for deeper insights into operations, trends and enable informed decision making). Overall, having data in one system simplifies operations, enhances efficiency, and empowers the company to make better informed decisions.

Operational Technology (OT) Datacenter Migration

Report Pulled: 11/1/2024 **Item ID: 13963**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , OT Datacenter Colo, OT Datacenter Migration, Operational Technology Datacenter Migration, Operational Technology (OT) Datacenter Migration

Description The OT environment consists of systems supporting the control and monitoring of electric grid, electric generation, gas compression, and natural gas pipeline. These systems are critical for safe and reliable natural gas and electric delivery. The OT Datacenter Migration project enhances the Company's capabilities by co-locating to an enhanced datacenter at a vendor facility.

Portfolio IT Services > Infrastructure > Data Center - Enterprise Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement The Company's current datacenter for the OT environment needs modernization and relocation from the Parnall Data Center. The current location is not the preferred location to house servers and systems critical to the control of the Electric Grid or Gas Pipeline due to the close proximity to a railway system. The climate conditioners in the current OT datacenter are aging and have had faults resulting in unplanned shutdowns . The location of the datacenter in the basement of the Parnall building is nearby to the main water piping for the building. There have been instances of water infiltration in the past.

Objectives This project creates value for the Company by significantly strengthening capabilities through: (1) mitigating legacy physical and location risks at the current Parnall site; (2) migrating the OT infrastructure to a modern, highly secured environment with redundancy in climate conditions; and (3) better datacenter facilities support with a guarantee of redundant power.

Scope The scope of the project includes: (1) migration of the OT environment from the Parnall Data Center to a co-located vendor data center; (2) re-validation of the OT Production and Disaster Recovery procedures once migration is completed; (3) migration of IT systems required for supporting the OT environment; and (4) decommission the existing OT environment from the Parnall location.

Alternatives The Company performed an analysis of alternatives to expand capabilities as well as address constraints and risks: (1) Remain at the current Parnall Data Center; (2) migrate OT environments to the Cloud; and (3) relocate to a third-party co-location facility. Current industry best practices do not recommend migration of OT environments to the cloud. The co-location vendor provides the building, cooling, power, and physical security the Company lacks for its servers, storage, and other computing and networking equipment at the current Parnall location. Based on the analysis, the Company decided to implement the third alternative.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
6/30/2026	9/8/2026	11/24/2026	1/15/2027
	In-Service/Go-Live	**Closeout**	
	11/16/2027	12/1/2027	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	$6.877	$0.872	-	-	-	-	-	$7.750
O&M	-	$2.311	$3.985	$1.816	$1.816	-	-	-	$9.928
Total Cost of Ownership	-	$9.188	$4.857	$1.816	$1.816	-	-	-	**$17.677**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	-	$0.600	$0.550	-	-	-	-	-	**$1.150**
Outside Services	-	$1.045	$1.040	-	-	-	-	-	**$2.085**
Business Expense/Overheads	-	$2.033	$1.451	-	-	-	-	-	**$3.484**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$5.010	-	-	-	-	-	-	**$5.010**
Licenses, Permits & Fees	-	$0.500	-	-	-	-	-	-	**$0.500**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$9.188	$3.041	-	-	-	-	-	**$12.229**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$2.311	$3.985	$1.816	$1.816	-	-	-	**$9.928**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$2.311	$3.985	$1.816	$1.816	-	-	-	**$9.928**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$6.877	$0.872	-	-	-	-	-	**$7.750**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$6.877	$0.872	-	-	-	-	-	**$7.750**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	There could be impacts to business services, customer service, and Company reputation.
Risk Mitigation	There is a need for enhancement to Consumer Energy's DR capabilities. Without a clear understanding of the risks, mitigation of those risks, and communication to all key stakeholders, the Company may not be able to recover from a loss of the primary data centers at Parnall. This risk may result in impacts to day-to-day operations and customers, which could have broader financial, reputational, and regulatory impacts.
Risk Mitigation	Using a vendor managed co-location datacenter reduces Company risk as it relates to NERC/CIP regulatory requirement Physical Security CIP-006-6
Intangibles	With the OT Datacenter migration, there is a highly secured environment, heating and cooling redundancy, and a guarantee of 100% power efficiency.

Oracle Server Database Upgrade 2023

Report Pulled: 11/1/2024 **Item ID: 12407**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias Oracle Database Upgrade,Oracle Server Database Upgrade, Oracle Server Database Upgrade 2023-2024, Oracle Server Database Upgrade 2023-2025, Oracle Server Database Upgrade 2023

Description This project will upgrade Oracle server databases to the next version to support all business portfolios.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement The Company is currently managing Oracle server databases that run on multiple versions of Oracle: 8i, 9i, 11g, and 12c; all of which are currently unsupported as of 12/31/2020. Version 12c recently lost vendor support in July of 2019 and is eligible for extended support. Relying on extended support for Version 12c increases operational costs by $121,000 annually. Extended support is not available for version 11g and older. Without vendor support, the databases no longer receive security patches, bug fixes, or functionality support which creates security, stability, and reliability risks.

Objectives This project will create value for the Company and its customers by: (1) reducing the risk of system failure and the resulting impacts to business partners and customers; and (2) ensuring that systems are secure, supported, and have the latest features and functionality. and (3) will do what we can to be complaint with Cyber Security Published standards, when possible. Many of the Cyber Security requirements are application dependent.

Scope The scope of this project includes upgrading to the next version of Oracle across all impacted business systems. Systems that cannot support current version of Oracle, will be upgraded to the highest supported version.

Alternatives Alternatives considered were; (1) delay database upgrades. This option was not chosen because, as stated, it would introduce significant security, stability and reliability risks; (2) Upgrade only to Version 12c and pay extended support. This option was not chosen, where possible, to avoid increased operational costs. The alternative chosen is to upgrade to the next version of Oracle and where systems do not support the current version of Oracle, upgrade to Version 12c and pay extended support until those systems are upgraded.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
7/1/2023	10/31/2023	11/30/2023	12/1/2023
	In-Service/Go-Live	**Closeout**	
	12/15/2023	12/31/2023	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.172	-	-	-	-	-	-	-	$0.172
Total Cost of Ownership	$0.172	-	-	-	-	-	-	-	**$0.172**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.051	-	-	-	-	-	-	-	**$0.051**
Outside Services	$0.111	-	-	-	-	-	-	-	**$0.111**
Business Expense/Overheads	$0.010	-	-	-	-	-	-	-	**$0.010**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.172	-	-	-	-	-	-	-	**$0.172**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.172	-	-	-	-	-	-	-	**$0.172**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.172	-	-	-	-	-	-	-	**$0.172**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	High	The Company is currently managing Oracle server databases that run on multiple versions of Oracle: 8i, 9i, 11g, and 12c; all of which are unsupported. Version 12c most recently lost vendor support in July of 2019 and is eligible for extended support, but it increases operational costs and is not available for version 11g and older. Without vendor support, the databases no longer receive security patches, bug fixes, or functionality support from the vendor, which creates security, stability, and reliability risk. The project mitigates these risks.

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	If the upgrade is not completed, the organization is at risk of security vulnerability and system failure. Oracle touches many business partners who will lose their ability to adequately perform their job tasks and customers, who will not be able to interact with the Company website or receive information from contact centers. After July of 2019, there will be no bug or functionality fixes for versions 11g and older.
Risk Mitigation	In the case of hardware, industry best practices suggest a five- to seven-year asset refresh cycle, while software, operating systems (OS), databases, and firmware typically require more frequent updates. Five to seven years is the useful window, according to market research Consumers Energy is making specific risk-based decisions on individual assets at the end of five years.
Intangibles	Many of the business areas that use Oracle are customer facing, including the contact centers and the website. If Oracle were to fail, the reputation of the organization would be at risk.
Intangibles	The outage management system would be impacted by a system failure. In the event of an unplanned outage, it would affect timely response to gas leaks, down wires, worker deployment, and field services.

Physical Access Management and Alarm Response

Report Pulled: 11/1/2024 **Item ID: 13976**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias , Physical Access Management and Alarm Response

Description The project will replace the Company's Physical Access Management System to establish a centralized platform that manages user identities, authenticates users, authorizes access, and audits user activities. The intent of this project is to consolidate and modernize the Company's physical security systems that will enable enhanced security monitoring to prevent unauthorized entry into sensitive corporate areas while providing increased flexibility to the Company's valued employees and contractors.

Portfolio Corporate Services > Security Services > Cyber Security & Shared Services > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STAN

WORK OBJECTIVES

Problem Statement The Company's Security Fusion Center (the Fusion Center is the Company's combined physical and cyber security operations center) is experiencing operational issues with the current physical access management system. The installation is out of date and causes inconsistent behavior when given tasks by automations within the Company's Identity Management solution. Frequent issues have been reported related to frozen jobs in the Company's existing access management solution due to the current system's database. This results in significant waste in the form of (1) waiting, the business partner is waiting much longer than they should have to for the system to process their request as un-freezing jobs is a manual process; (2) lost productivity, that waiting can cause for the business partner as it can either prevent them from accessing sites they need, or slow them down unnecessarily while they work with others to be escorted; (3) rework, because frozen jobs don't always run correctly when unfrozen, meaning the business partner has to resubmit their request and/or Identity Operations has to do additional work to satisfy the original request; and (4) alarms can cause a frozen state that impact system stability and reduces security visibility as a result. Not moving to new technology also carries a growing risk of outright system failure which could result in unauthorized physical access and/or impact the Company's ability to efficiently function. The current installation of the physical access management system and the Company's current card readers do not support next generation physical access control methods, such as digital ID. This prevents the Company from adopting new methods and practices that can lower costs and improve control and responsiveness. All employees, contractors, staff, and visitors are impacted by the problem.

Objectives This project creates value for the Company by: (1) developing an alarm and event monitoring system, which will enable seamless orchestration of system alarms and cameras; (2) adding automation that will streamline remediation processes and orchestrate camera operations for efficiency; (3) refining access revocation and badge access management to ensure only authorized personnel have entry privileges; (4) introducing new access control readers that will modernize the system, allowing for the use of mobile device badges for employees, contractors, and visitors, offering a more flexible and user-friendly experience for those entering the Company's facilities.

Scope The project scope includes modernizing the Company's current physical access control system, badge system, badge access hardware and firmware, and all 3000 card readers across facilities and assets. This will require modernization of all physical badge access readers and the implementation of hardware and software necessary to run the physical access control system. In addition, there will be substantial automation and integration between the security orchestration solution and the physical access control systems to realize the full benefits of this initiative.

Alternatives Alternatives considered were: (1) Keeping the current physical access control system and processes as-is. This alternative was not selected as the current platform is outdated, increasingly expensive to support, and does not include modern capabilities, such as digital IDs. It also does not reduce waste, cost, and it does not improve speed to delivery; (2) Developing a custom, in-house physical access control solution that includes modern capabilities, such as digital IDs. This option was not selected as the Company lacks the expertise to build such a solution. Custom-developed solutions have higher long-term, and generally result in significant waste, as well as lower speed to delivery; and (3) Implementing a new physical access control system that includes modern capabilities, such as digital IDs, that reduces waste and cost and improves speed to delivery. There are vendors in the market that specialize in physical access control systems that offer proven capabilities the Company is looking to implement. This option was selected as it will allow the Company to meet its objectives of lower waste, lower cost, improved speed to delivery, by implementing digital IDs and enabling tighter integration between the physical access control system and the Company's other security platforms.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/15/2026	2/28/2026	4/28/2026	2/25/2027
	In-Service/Go-Live	**Closeout**	
	2/26/2027	12/1/2029	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	$3.234	$1.551	$1.551	-	-	-	-	-	$6.335
O&M	$0.328	$0.345	$0.345	$0.187	-	-	-	-	$1.205
Total Cost of Ownership	$3.562	$1.896	$1.896	$0.187	-	-	-	-	**$7.540**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.419	$0.388	$0.388	$0.187	-	-	-	-	**$1.382**
Outside Services	$0.225	$0.135	$0.135	-	-	-	-	-	**$0.495**
Business Expense/Overheads	$0.280	$0.143	$0.143	-	-	-	-	-	**$0.565**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$1.130	$1.125	$1.125	-	-	-	-	-	**$3.380**
Licenses, Permits & Fees	$1.508	$0.105	$0.105	-	-	-	-	-	**$1.718**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$3.562	$1.896	$1.896	$0.187	-	-	-	-	**$7.540**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.328	$0.345	$0.345	$0.187	-	-	-	-	**$1.205**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.328	$0.345	$0.345	$0.187	-	-	-	-	**$1.205**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$3.234	$1.551	$1.551	-	-	-	-	-	**$6.335**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$3.234	$1.551	$1.551	-	-	-	-	-	**$6.335**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
System Failure (SAP & Other)	Medium	Medium	This system replacement will reduce current operating risk managing multiple physical access management platforms.

OTHER VALUE

Type	Description
Technology Capability	Access revocation and badge access management will be refined to ensure only authorized personnel have entry privileges
Technology Capability	Development of a sophisticated Alarm and Event monitoring system will enable seamless orchestration of system alarms and cameras. This will facilitate proactive camera monitoring and rapid response to incidents.
Technology Capability	The impact of the project is to allow physical entry for employees, contractors, and visitors who are authorized to do work for the Company while minimizing barriers.
Technology Capability	The new system will introduce new access control readers that will modernize the system, allowing for the use of mobile device badges for employees, contractors, and visitors, offering a more flexible and user-friendly experience for those entering the Company's facilities.
Technology Capability	The new system will seamlessly integrate with mobile badging, allowing for efficient contractor and visitor management, which is particularly crucial during emergency situations such as storms.
Technology Capability	The project will give the ability to integrate badge entry data with security camera data and other security platforms to perform cross system monitoring and flagging. This impact will allow the Company to build more effective alerts that can be responded to in a more deliberate manner.

Pipeline SCADA Security

Report Pulled: 11/1/2024 **Item ID: 10487**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - One Time **Work Type** Project

Alias , Gas SCADA Cyber Security, Pipeline SCADA Security

Description This project will implement major modifications to the Gas Supervisory Control and Data Acquisition (SCADA) environment to ensure compliance to American Petroleum Institute (API) 1164 standard. API 1164 is an MPSC regulatory requirement with recent updates to the Gas Technical Standards. The project will implement IT, cyber security, and physical security equipment and site modifications necessary for regulatory compliance to API 1164.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-COMPLIANCE

WORK OBJECTIVES

Problem Statement The MPSC requires the implementation of pipeline cyber security regulations pursuant to API 1164 on the Company natural gas pipeline system. The Company's Gas SCADA system is outdated and non-standardized, requiring significant modifications to be compliant with API 1164. Without the technology updates, the gas SCADA system is vulnerable to cyber-attacks that potentially risk disrupting delivery to customers. Interruptions in gas delivery and non-compliance to API 1164 mandated requirements could be subject to fines and penalties from the MPSC and other regulatory entities (i.e., the Transportation Security Administration).

Objectives This project will add value to the Company by: (1) modernizing and standardizing the Gas SCADA network at the Company's gas compressor stations and control rooms; (2) mitigating cyber security vulnerabilities in the Gas SCADA network; (3) allowing the Company to fully comply with API 1164 requirements; and (4) fulfilling the commitment to the MPSC to provide a secure gas system that meets customer needs.

Scope The project scope includes updates for multiple gas SCADA-related locations, including: eight gas compressor stations, two gas control rooms, two data centers, and multiple intelligent pipeline field devices. To establish compliance with API 1164, the project will: (1) design a holistic network architecture to implement both physical and technical changes; (2) implement physical enhancements to impacted facilities, such as additional closets or data rooms, and modified HVAC systems to provide necessary climate control for the SCADA equipment; (3) install additional security cameras and/or card readers necessary to control access to new and existing equipment; (4) complete technology upgrades requiring design, development, testing and implementation for the Gas SCADA network at each of the planned locations. Upgrades will consist of endpoint protection, identity and access management, vulnerability management, business continuity capabilities, cyber incident response, asset management, and commensurate test environments; and (5) implement additional security measures on field devices, including change default credentials, secure communications, change management, and patching activities.

Alternatives As this is a regulatory compliance requirement, there are no alternatives to completing this project. Without the completion of this project, the Company could be subject to noncompliance fines and penalties from the MPSC.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
6/1/2020	10/31/2020	3/1/2021	6/30/2022
	In-Service/Go-Live	**Closeout**	
	7/1/2022	10/31/2023	

FUNDING SUMMARY

	2020	2021	2022	2023	2024	2025	2026	2027 +	Total
Cap+COR	$0.757	$2.663	$4.478	$4.055	$0.640	-	-	-	$12.593
O&M	$0.047	$0.080	$0.146	$0.151	$0.118	-	-	-	$0.543
Total Cost of Ownership	$0.804	$2.743	$4.624	$4.206	$0.757	-	-	-	**$13.136**

	2020	2021	2022	2023	2024	2025	2026	2027 +	Total
Labor	$0.096	$0.692	$0.881	$1.303	$0.325	-	-	-	**$3.296**
Outside Services	$0.319	$0.142	$1.029	$1.409	$0.235	-	-	-	**$3.135**
Business Expense/Overheads	$0.045	$0.329	$0.357	$0.900	$0.138	-	-	-	**$1.769**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.223	$1.316	$1.951	$0.373	$(0.077)	-	-	-	**$3.785**
Licenses, Permits & Fees	$0.122	$0.263	$0.407	$0.222	$0.136	-	-	-	**$1.151**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.804	$2.743	$4.624	$4.206	$0.757	-	-	-	**$13.136**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2020	2021	2022	2023	2024	2025	2026	2027 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.047	$0.080	$0.146	$0.151	$0.118	-	-	-	**$0.543**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.047	$0.080	$0.146	$0.151	$0.118	-	-	-	**$0.543**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.757	$2.663	$4.478	$4.055	$0.640	-	-	-	**$12.593**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.757	$2.663	$4.478	$4.055	$0.640	-	-	-	**$12.593**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Unplanned Outages - Gas	High	Low	Unplanned Outage - Gas Supply (SCADA): The risk of loss of operational control of all or a portion of the gas system for an extended period due to a cyber-attack, resulting in disruption of business operations, including lost revenue, restoration costs, and reputational damage.
Unplanned Outages - Generation	High	Low	Unplanned Outage - Generation: Risk of an unplanned outage at one or more large power plants for an extended period due to a cyber-attack

OTHER VALUE

Type	Description
Technology Capability	Electric T&D, Gas T&D, Generation
Risk Mitigation	modernizing and standardizing the Gas SCADA network at the Company's gas compressor stations and controls rooms will help mitigate unplanned outage and cyber security related risks seen with Gas Supply and Generation.

Product Family Enhancements-Application Platforms Service Report Pulled: 11/1/2024 Item ID: 13931

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Portfolio

Alias , Product Family Enhancements-IT/Digital Foundation-Capital, Product Family Enhancements-Application Platforms and Services, Product Family Enhancements-Application Platforms and Services-Capital, Product Family Enhancements-Application Platforms Services-Capital

Description The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.708	$0.956	$0.956	$0.956	$0.956	$0.956	-	-	$5.487
O&M	$0.230	$0.132	$0.306	$0.306	$0.306	$0.306	-	-	$1.586
Total Cost of Ownership	$0.939	$1.088	$1.262	$1.262	$1.262	$1.262	-	-	**$7.072**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.882	$0.605	$0.779	$0.779	$0.779	$0.779	-	-	**$4.603**
Outside Services	$0.026	$0.157	$0.157	$0.157	$0.157	$0.157	-	-	**$0.811**
Business Expense/Overheads	$0.023	$0.326	$0.326	$0.326	$0.326	$0.326	-	-	**$1.652**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.008	-	-	-	-	-	-	-	**$0.008**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.939	$1.088	$1.262	$1.262	$1.262	$1.262	-	-	**$7.072**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.230	$0.132	$0.306	$0.306	$0.306	$0.306	-	-	**$1.586**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.230	$0.132	$0.306	$0.306	$0.306	$0.306	-	-	**$1.586**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.708	$0.956	$0.956	$0.956	$0.956	$0.956	-	-	**$5.487**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.708	$0.956	$0.956	$0.956	$0.956	$0.956	-	-	**$5.487**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Application Platforms Service Report Pulled: 11/1/2024 Item ID: 13933

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-IT/Digital Foundation-O&M, Product Family Enhancements-Application Platforms and Services-O&M, Product Family Enhancements-Application Platforms Services-O&M

Description The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SERV

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope

Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management.

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.000	$0.390	$0.289	$0.115	$0.115	$0.115	$0.115	-	$1.139
Total Cost of Ownership	$0.000	$0.390	$0.289	$0.115	$0.115	$0.115	$0.115	-	**$1.139**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.000	$0.384	$0.245	$0.107	$0.107	$0.107	$0.107	-	**$1.059**
Outside Services	-	-	-	-	-	-	-	-	**-**
Business Expense/Overheads	$0.000	$0.006	$0.044	$0.008	$0.008	$0.008	$0.008	-	**$0.080**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.000	$0.390	$0.289	$0.115	$0.115	$0.115	$0.115	-	**$1.139**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.000	$0.390	$0.289	$0.115	$0.115	$0.115	$0.115	-	**$1.139**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.000	$0.390	$0.289	$0.115	$0.115	$0.115	$0.115	-	**$1.139**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Corporate-Capital

Report Pulled: 11/1/2024 **Item ID: 13372**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Corporate-Capital

Description The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services.

Scope The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.929	$1.814	$3.849	$2.929	$2.929	$2.929	$2.929	-	$18.309
O&M	$0.036	$0.119	$0.552	$0.418	$0.418	$0.418	$0.418	-	$2.382
Total Cost of Ownership	$0.965	$1.933	$4.401	$3.348	$3.348	$3.348	$3.348	-	**$20.691**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.134	$1.056	$2.976	$2.251	$2.251	$2.251	$2.251	-	**$13.170**
Outside Services	$0.748	$0.376	$0.063	$0.063	$0.063	$0.063	$0.063	-	**$1.438**
Business Expense/Overheads	$0.084	$0.061	$1.362	$1.034	$1.034	$1.034	$1.034	-	**$5.643**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.440	-	-	-	-	-	-	**$0.440**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.965	$1.933	$4.401	$3.348	$3.348	$3.348	$3.348	-	**$20.691**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.036	$0.119	$0.552	$0.418	$0.418	$0.418	$0.418	-	**$2.382**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.036	$0.119	$0.552	$0.418	$0.418	$0.418	$0.418	-	**$2.382**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.929	$1.814	$3.849	$2.929	$2.929	$2.929	$2.929	-	**$18.309**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.929	$1.814	$3.849	$2.929	$2.929	$2.929	$2.929	-	**$18.309**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description

Product Family Enhancements-Corporate-O&M

Report Pulled: 11/1/2024 **Item ID: 13373**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Corporate-O&M

Description The Corporate Services initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements in the Corporate Services Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Corporate Services.

Scope

The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as People and Culture (Human Resources), Legal, Finance and Governmental, Regulatory and, Public Affairs.

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.212	$0.185	$0.556	$0.459	$0.345	$0.345	$0.345	-	$2.447
Total Cost of Ownership	$0.212	$0.185	$0.556	$0.459	$0.345	$0.345	$0.345	-	**$2.447**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.106	$0.049	$0.519	$0.429	$0.323	$0.323	$0.323	-	**$2.071**
Outside Services	$0.093	$0.133	-	-	-	-	-	-	**$0.226**
Business Expense/Overheads	$0.013	$0.003	$0.036	$0.030	$0.023	$0.023	$0.023	-	**$0.150**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.212	$0.185	$0.556	$0.459	$0.345	$0.345	$0.345	-	**$2.447**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.212	$0.185	$0.556	$0.459	$0.345	$0.345	$0.345	-	**$2.447**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.212	$0.185	$0.556	$0.459	$0.345	$0.345	$0.345	-	**$2.447**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description

Product Family Enhancements-Customer-Capital

Report Pulled: 11/1/2024 **Item ID: 13374**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Customer-Capital

Description The Customer initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope

Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management.

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.246	$1.733	$7.711	$5.821	$4.748	$4.748	$4.748	-	$29.755
O&M	$0.019	$0.825	$0.907	$0.757	$0.682	$0.682	$0.682	-	$4.555
Total Cost of Ownership	$0.266	$2.558	$8.618	$6.578	$5.430	$5.430	$5.430	-	**$34.310**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.049	$0.207	$4.467	$2.958	$2.188	$2.188	$2.188	-	**$14.244**
Outside Services	$0.216	$2.252	$2.140	$2.336	$2.336	$2.336	$2.336	-	**$13.952**
Business Expense/Overheads	$0.001	$0.100	$2.011	$1.284	$0.907	$0.907	$0.907	-	**$6.115**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.266	$2.558	$8.618	$6.578	$5.430	$5.430	$5.430	-	**$34.310**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.019	$0.825	$0.907	$0.757	$0.682	$0.682	$0.682	-	**$4.555**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.019	$0.825	$0.907	$0.757	$0.682	$0.682	$0.682	-	**$4.555**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.246	$1.733	$7.711	$5.821	$4.748	$4.748	$4.748	-	**$29.755**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.246	$1.733	$7.711	$5.821	$4.748	$4.748	$4.748	-	**$29.755**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Customer-O&M

Report Pulled: 11/1/2024 **Item ID: 13375**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Customer-O&M

Description The Customer initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements in the Customer Portfolio lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope

Included in the implementation are small changes and functionality improvements to existing IT software application investments for Customer. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Customer Experience and Operations, Applications Support and, Device Management.

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.387	$0.034	$0.434	$0.434	$0.434	$0.434	$0.434	-	$2.592
Total Cost of Ownership	$0.387	$0.034	$0.434	$0.434	$0.434	$0.434	$0.434	-	**$2.592**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.024	$0.002	$0.269	$0.269	$0.269	$0.269	$0.269	-	**$1.371**
Outside Services	$0.337	$0.031	$0.088	$0.088	$0.088	$0.088	$0.088	-	**$0.806**
Business Expense/Overheads	$0.025	$0.001	$0.078	$0.078	$0.078	$0.078	$0.078	-	**$0.415**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.387	$0.034	$0.434	$0.434	$0.434	$0.434	$0.434	-	**$2.592**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.387	$0.034	$0.434	$0.434	$0.434	$0.434	$0.434	-	**$2.592**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.387	$0.034	$0.434	$0.434	$0.434	$0.434	$0.434	-	**$2.592**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Electric & Gas Shared-Capit: Report Pulled: 11/1/2024 — Item ID: 13376

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow — **Work Type** Project

Alias , Product Family Enhancements-Electric & Gas Shared-Capital

Description The Electric and Gas operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T — **Bus Unit** INFORMATION TECHNOLOGY — **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in Electric and Gas operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Companys ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation — **Project Plan & Scope Definition** — **Final Engineering, Planning & Design** — **Execution** — **In-Service/Go-Live** — **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.113	$1.374	$0.848	$0.848	$0.848	$0.848	$0.668	-	$5.549
O&M	-	$0.184	$0.065	$0.065	$0.065	$0.065	$0.063	-	$0.507
Total Cost of Ownership	$0.113	$1.558	$0.914	$0.914	$0.914	$0.914	$0.731	-	**$6.057**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.027	$0.814	$0.123	$0.123	$0.123	$0.123	$0.123	-	**$1.458**
Outside Services	$0.073	$0.703	$0.390	$0.390	$0.390	$0.390	$0.390	-	**$2.726**
Business Expense/Overheads	$0.013	$0.042	$0.362	$0.362	$0.362	$0.362	$0.179	-	**$1.681**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.039	$0.039	$0.039	$0.039	$0.039	-	**$0.193**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.113	$1.558	$0.914	$0.914	$0.914	$0.914	$0.731	-	**$6.057**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.184	$0.065	$0.065	$0.065	$0.065	$0.063	-	**$0.507**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.184	$0.065	$0.065	$0.065	$0.065	$0.063	-	**$0.507**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.113	$1.374	$0.848	$0.848	$0.848	$0.848	$0.668	-	**$5.549**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.113	$1.374	$0.848	$0.848	$0.848	$0.848	$0.668	-	**$5.549**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Electric & Gas Shared-O&M Report Pulled: 11/1/2024 Item ID: 13377

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Electric & Gas Shared-O&M

Description The Electric and Gas operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements in Electric and Gas Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Electric and Gas Operations.

Scope

The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Electric, Gas and Generation Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls.

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Companys ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.029	$0.038	$0.183	$0.183	$0.183	$0.183	$0.183	-	$0.984
Total Cost of Ownership	$0.029	$0.038	$0.183	$0.183	$0.183	$0.183	$0.183	-	**$0.984**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.010	$0.019	$0.155	$0.155	$0.155	$0.155	$0.155	-	**$0.803**
Outside Services	$0.017	$0.017	$0.014	$0.014	$0.014	$0.014	$0.014	-	**$0.103**
Business Expense/Overheads	$0.002	$0.001	$0.012	$0.012	$0.012	$0.012	$0.012	-	**$0.064**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.003	$0.003	$0.003	$0.003	$0.003	-	**$0.013**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.029	$0.038	$0.183	$0.183	$0.183	$0.183	$0.183	-	**$0.984**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.029	$0.038	$0.183	$0.183	$0.183	$0.183	$0.183	-	**$0.984**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.029	$0.038	$0.183	$0.183	$0.183	$0.183	$0.183	-	**$0.984**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Gas-Capital

Report Pulled: 11/1/2024 **Item ID: 13380**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Gas-Capital

Description The Gas Engineering and Operations initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Gas Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-GAS

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements in Gas Engineering and Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments for Gas Engineering and Operations. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering and Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.309	$0.428	$0.680	$1.523	$0.680	$0.680	$0.680	-	$4.980
O&M	-	$0.088	$0.085	$0.182	$0.085	$0.085	$0.085	-	$0.612
Total Cost of Ownership	$0.309	$0.516	$0.765	$1.705	$0.765	$0.765	$0.765	-	**$5.592**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.082	$0.191	$0.293	$0.933	$0.293	$0.293	$0.293	-	**$2.381**
Outside Services	$0.185	$0.282	$0.187	$0.187	$0.187	$0.187	$0.187	-	**$1.403**
Business Expense/Overheads	$0.042	$0.042	$0.285	$0.585	$0.285	$0.285	$0.285	-	**$1.808**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.309	$0.516	$0.765	$1.705	$0.765	$0.765	$0.765	-	**$5.592**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.088	$0.085	$0.182	$0.085	$0.085	$0.085	-	**$0.612**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.088	$0.085	$0.182	$0.085	$0.085	$0.085	-	**$0.612**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.309	$0.428	$0.680	$1.523	$0.680	$0.680	$0.680	-	**$4.980**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.309	$0.428	$0.680	$1.523	$0.680	$0.680	$0.680	-	**$4.980**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Gas-O&M

Report Pulled: 11/1/2024 **Item ID: 13381**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-Gas-O&M

Description The Gas Engineering and Operations initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Gas Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-GAS

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements in Gas Engineering and Operations lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment. Included in the implementation are small changes and functionality improvements to existing IT software application investments for Gas Engineering and Operations.

Scope

The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as Gas Engineering and Operations, Operations Performance, Operations and Financial Reporting and, Operations Compliance and Controls.

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.235	$0.002	$0.239	$0.239	$0.239	$0.239	$0.239	-	$1.434
Total Cost of Ownership	$0.235	$0.002	$0.239	$0.239	$0.239	$0.239	$0.239	-	**$1.434**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.066	-	$0.202	$0.202	$0.202	$0.202	$0.202	-	**$1.076**
Outside Services	$0.155	$0.002	$0.013	$0.013	$0.013	$0.013	$0.013	-	**$0.223**
Business Expense/Overheads	$0.014	$0.000	$0.020	$0.020	$0.020	$0.020	$0.020	-	**$0.114**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.004	$0.004	$0.004	$0.004	$0.004	-	**$0.021**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.235	$0.002	$0.239	$0.239	$0.239	$0.239	$0.239	-	**$1.434**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.235	$0.002	$0.239	$0.239	$0.239	$0.239	$0.239	-	**$1.434**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.235	$0.002	$0.239	$0.239	$0.239	$0.239	$0.239	-	**$1.434**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Infrastructure Platforms Serv Report Pulled: 11/1/2024 Item ID: 13932

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Portfolio

Alias , Product Family Enhancements-IT/Digital Foundation-Capital, Product Family Enhancements-Application Platforms and Services, Product Family Enhancements-Infrastructure Platforms and Services-Capital, Product Family Enhancements-Infrastructure Platforms Services-Capital

Description The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software & hardware and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$0.702	$1.094	$0.573	$0.573	$0.573	$0.573	-	-	$4.090
O&M	$0.350	$0.149	$0.184	$0.184	$0.184	$0.184	-	-	$1.233
Total Cost of Ownership	$1.052	$1.243	$0.757	$0.757	$0.757	$0.757	-	-	**$5.323**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.610	$0.762	$0.467	$0.467	$0.467	$0.467	-	-	**$3.241**
Outside Services	$0.095	$0.094	$0.094	$0.094	$0.094	$0.094	-	-	**$0.566**
Business Expense/Overheads	$0.347	$0.387	$0.195	$0.195	$0.195	$0.195	-	-	**$1.516**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$1.052	$1.243	$0.757	$0.757	$0.757	$0.757	-	-	**$5.323**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.350	$0.149	$0.184	$0.184	$0.184	$0.184	-	-	**$1.233**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.350	$0.149	$0.184	$0.184	$0.184	$0.184	-	-	**$1.233**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.702	$1.094	$0.573	$0.573	$0.573	$0.573	-	-	**$4.090**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.702	$1.094	$0.573	$0.573	$0.573	$0.573	-	-	**$4.090**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-Infrastructure Platforms Serv Report Pulled: 11/1/2024 Item ID: 13934

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-IT/Digital Foundation-O&M, Product Family Enhancements-Application Platforms and Services-O&M, Product Family Enhancements-Infrastructure Platforms and Services-O&M, Product Family Enhancements-Infrastructure Platforms Services-O&M

Description The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement
As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives
The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope
Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management.

Alternatives
Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.331	$0.143	$0.332	$0.216	$0.216	$0.216	-	-	$1.454
Total Cost of Ownership	$0.331	$0.143	$0.332	$0.216	$0.216	$0.216	-	-	**$1.454**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.309	$0.122	$0.310	$0.202	$0.202	$0.202	-	-	**$1.346**
Outside Services	-	-	-	-	-	-	-	-	**-**
Business Expense/Overheads	$0.022	$0.022	$0.022	$0.014	$0.014	$0.014	-	-	**$0.107**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.331	$0.143	$0.332	$0.216	$0.216	$0.216	-	-	**$1.454**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.331	$0.143	$0.332	$0.216	$0.216	$0.216	-	-	**$1.454**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.331	$0.143	$0.332	$0.216	$0.216	$0.216	-	-	**$1.454**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-IT/Digital Foundation-Capital Report Pulled: 11/1/2024 Item ID: 13382

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-IT/Digital Foundation-Capital

Description The IT initiative will utilize both Capital and O&M funding to make enhancements to existing software and to address requests generated by changing business requirements. O&M is included in this project to complete expense activities associated with Capital enhancements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management.

Alternatives Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.268	$1.034	-	-	-	-	-	-	$1.302
O&M	$0.048	$0.274	-	-	-	-	-	-	$0.322
Total Cost of Ownership	$0.316	$1.308	-	-	-	-	-	-	**$1.624**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.105	$1.107	-	-	-	-	-	-	**$1.212**
Outside Services	$0.056	$0.130	-	-	-	-	-	-	**$0.186**
Business Expense/Overheads	$0.025	$0.059	-	-	-	-	-	-	**$0.084**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.099	$0.003	-	-	-	-	-	-	**$0.102**
Licenses, Permits & Fees	$0.031	$0.009	-	-	-	-	-	-	**$0.040**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.316	$1.308	-	-	-	-	-	-	**$1.624**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.048	$0.274	-	-	-	-	-	-	**$0.322**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.048	$0.274	-	-	-	-	-	-	**$0.322**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.268	$1.034	-	-	-	-	-	-	**$1.302**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.268	$1.034	-	-	-	-	-	-	**$1.302**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Product Family Enhancements-IT/Digital Foundation-O&M

Report Pulled: 11/1/2024 **Item ID:** 13383

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Product Family Enhancements-IT/Digital Foundation-O&M

Description The IT initiative will utilize O&M funding to make enhancements to existing software and to address requests generated by changing business requirements.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement

As business processes improve and change, new requirements surface that call for smaller-effort software application changes that typically emerge from new or changing business conditions, compliance requirements, needs for new capabilities, customer feedback, and other improvement ideas Enhancing applications requires a short timeframe between inception and implementation and cannot and should not wait for rate case approval at an individual line-item level. Failure to make these changes to applications can have a direct negative impact on key customer and business processes, increase support costs, and limit the Company's ability to consistently meet objectives.

Objectives

The value of software enhancements that benefit the IT organization lies in: (1) cost savings and cost avoidance; (2) technology and business process efficiencies; (3) improved customer experience; (4) risk mitigation; (5) safety improvements; and (6) achieving corporate goals, among others. While these small-work software efforts are neither projects nor operational work, funding for resources is still required to maintain business agility in the digital environment.

Scope

Included in the implementation are small changes and functionality improvements to existing IT software application investments that are utilized by IT employees in support of tracking hardware and software fixes and managing technology projects for the various business areas within the Company. The scope of application enhancements encompasses: (1) making necessary system changes, and (2) updating documentation related to the changes. Additionally, enhancement requests are fulfilled to provide functionality for areas such as IT resource management, IT project management, IT financial and regulatory, IT applications operations, and IT infrastructure management.

Alternatives

Prior to implementing an enhancement, a review is completed to identify the best solution. During that review, requests for this funding are governed by a cross-functional board comprised of representatives from each area that routinely evaluates and prioritizes the work and to assess requests for value using categorized benefits. In addition, the overall enhancements budget is reviewed annually, and the alternative of a zero-budget allocation for enhancements is considered. This project fortifies the Company's ability to make software changes as part of process improvements and regulatory changes, and to meet legally required system changes. Without funding for enhancements, the Company will be limited in its ability to quickly provide needed capabilities and improvements.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.040	$0.357	-	-	-	-	-	-	$0.396
Total Cost of Ownership	$0.040	$0.357	-	-	-	-	-	-	**$0.396**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.015	$0.299	-	-	-	-	-	-	**$0.314**
Outside Services	$0.022	$0.054	-	-	-	-	-	-	**$0.077**
Business Expense/Overheads	$0.003	$0.003	-	-	-	-	-	-	**$0.006**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.040	$0.357	-	-	-	-	-	-	**$0.396**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.040	$0.357	-	-	-	-	-	-	**$0.396**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.040	$0.357	-	-	-	-	-	-	**$0.396**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintaining an optimal degree of application currency helps the Company to avoid: (1) application failure, (2) an increased number of incidents, (3) paying increased support costs, and (4) disruption of employee work completion. The benefit of implementing the enhancements will be reviewed and agreed upon by the cross organization governance board.

Public Key Infrastructure (PKI) Upgrade

Report Pulled: 11/1/2024 **Item ID: 13691**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias , Public Key Infrastructure (PKI) Upgrade

Description Replace on-premise PKI to stay supported by the manufacturer.

Portfolio IT Services > Infrastructure > Data Center - Enterprise Computing > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STANI

WORK OBJECTIVES

Problem Statement The existing PKI that issues certificates to IT systems for secure communications needs to be upgraded to stay supported by the manufacturer. If the PKI is not maintained, in the event of a system failure the Company would not have support in recovering. All IT systems requiring secure communications via certificates would go offline within three days.

Objectives Replace existing PKI with new PKI that is supported by the manufacturer.

Scope The project will build and configure the servers necessary to provide Public Key Infrastructure services, put in place physical token management for maintaining security, migrate certificate issuing and management to the new system and decommission the old system.

Alternatives The Company has a limited use service for PKI on the Internet only. (1) The Company looked into expanding the service to include usage on the Company network but found the solution to not be economically viable. (2) The Company also looked at full cloud solutions, but it did not meet the security standards currently being used around physical token use. (3) The Company looked at continuing extended support, however the continuing extended support is not available by the vendor. (4) The Company selected a hybrid solution of part cloud and part on-premise to meet all operational and security compliance requirements. The opportunity is to retain ownership of the keys on-premise prior to evaluating ownership through the cloud.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
10/9/2023	10/23/2023	12/4/2023	12/15/2023
	In-Service/Go-Live	**Closeout**	
	7/1/2024	7/12/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.305	$1.513	-	-	-	-	-	-	$1.818
O&M	$0.162	$0.262	-	-	-	-	-	-	$0.424
Total Cost of Ownership	$0.467	$1.775	-	-	-	-	-	-	**$2.242**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.011	$0.418	-	-	-	-	-	-	**$0.429**
Outside Services	$0.085	$0.549	-	-	-	-	-	-	**$0.633**
Business Expense/Overheads	$0.034	$0.050	-	-	-	-	-	-	**$0.085**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	$0.132	$0.649	-	-	-	-	-	-	**$0.781**
Licenses, Permits & Fees	$0.205	$0.108	-	-	-	-	-	-	**$0.314**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$0.467	$1.775	-	-	-	-	-	-	**$2.242**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.162	$0.262	-	-	-	-	-	-	**$0.424**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.162	$0.262	-	-	-	-	-	-	**$0.424**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.305	$1.513	-	-	-	-	-	-	**$1.818**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.305	$1.513	-	-	-	-	-	-	**$1.818**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
System Failure (SAP & Other)	High	Medium	Consumers Energy's vendor, Thales only offers full support for seven years after purchase of a solution. After the end of support no more operational or security patches are available and if an issue is encountered the manufacturer will not assist in resolving.

OTHER VALUE

Type	Description
Risk Mitigation	DR Risks/Impacts Description – If the Company doesn't upgrade to a supported version and the system becomes unrecoverable, we are at risk of the of the following: (1) Lost productivity of approximately 8,000 employees and 4,000 contractors who are unable to access system is estimated to be 3.12M (Half day – 13,000 *$60 *4 hours) to 12.48M (2 days – 13,000 people * $60 * 16 hours). (2) Deferred revenue – payment from customers estimated to be $12-44M daily. (3) Life Safety Incidents – loss of ability to report a down powerline, gas leak type events. (4) Negatively impacts our ability to assist with Storm Restoration. (5) Call centers will go down.
Risk Mitigation	The Company's research demonstrates that industry standards on refreshing hardware are generally three to five years. Using these recommendations allows the Company to: (1) Avoid increasing costs as the result of hardware failures; (2) avert customer frustration and employee downtime; (3) reduce security risks by ensuring that devices are updated and patched to prevent vulnerabilities; (4) continue operating system support as older versions are retired by the manufacturer; and (5) ensure employees have the required software to perform their work.

Radar Intrusion Detection

Report Pulled: 11/1/2024 **Item ID: 8846**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Radar Intrusion Detection

Description This project will deploy new radar detection technology to enable the detection and tracking of individuals at Company sites. The radar will alert in real time and automatically dispatch Company security or law enforcement to investigate.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** SECURITY

WORK OBJECTIVES

Problem Statement

The Company currently lacks the ability to detect potential intruders at Company sites across the state, including critical infrastructure sites such as city gates, compressor stations, sub stations, generation plants, and hydro sites. Currently, three sites have flawed fence intrusion detection technology that result in the recurrence of multiple false alarms that require an employee to investigate. Additionally, the current detection technology is unable to identify the difference between animals and humans, cannot set different boundaries, and prohibits the expansion of intrusion detection at many other critical sites. Any Investigation that has to be done is hampered by the limitations of the current system, requiring manual frame by frame review of video playback is manually intensive and time consuming.

Objectives

Completion of this project will provide value to the Company through evaluating and selecting a more reliable intrusion detection solution that reduces the number of false alarms and prevents resources from being sent to a site for unnecessary investigations. Additionally, the project will improve the efficiency of investigations by reducing the amount of time it takes to review playback to develop a suspect or investigative lead. In most cases this will be eliminated completely. This added layer of security benefits both the Company through waste elimination, as well as the Company's customers through the safety and security of assets necessary to continue to serve.

Scope

The scope of this project encompasses: (1) implementing radar intrusion detection options; (2) establishing a priority list of sites where the solution will be rolled out; and (3) installing updated radar intrusion at physical sites in the Company's service territory with a focus on critical infrastructure sites, including but not limited to gas compressor stations, electric substations, and hydro-electric sites.

Alternatives

Alternatives considered included: (1) keeping the current fence intrusion detection solution; or (2) implementing a new intrusion detection solution. The preferred option is to implement a new solution, given the above limitations with the current solution.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/31/2020	2/28/2020	8/31/2020	7/31/2021
	In-Service/Go-Live	**Closeout**	
	8/31/2022	8/31/2023	

FUNDING SUMMARY

	2019	2020	2021	2022	2023	2024	2025	2026 +	Total
Cap+COR	-	$0.186	$0.889	$1.548	$0.360	$(0.022)	-	-	$2.960
O&M	-	$0.000	$0.006	$0.004	-	-	-	-	$0.010
Total Cost of Ownership	-	$0.186	$0.894	$1.553	$0.360	$(0.022)	-	-	**$2.971**

	2019	2020	2021	2022	2023	2024	2025	2026 +	Total
Labor	-	$0.061	$0.024	$0.085	$0.026	-	-	-	**$0.196**
Outside Services	-	$0.116	$0.253	$1.197	$(0.251)	$0.002	-	-	**$1.316**
Business Expense/Overheads	-	$0.009	$0.005	$0.026	$0.009	-	-	-	**$0.049**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	$0.612	$0.245	$0.576	$(0.024)	-	-	**$1.410**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$0.186	$0.894	$1.553	$0.360	$(0.022)	-	-	**$2.971**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2019	2020	2021	2022	2023	2024	2025	2026 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.000	$0.006	$0.004	-	-	-	-	**$0.010**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.000	$0.006	$0.004	-	-	-	-	**$0.010**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.186	$0.889	$1.548	$0.360	$(0.022)	-	-	**$2.960**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.186	$0.889	$1.548	$0.360	$(0.022)	-	-	**$2.960**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Unplanned Outages - Electric	Low	Low	Physical Security - Substations: The risk of someone causing malicious physical damage to an electric substation, resulting in repair/replacement costs and a disruption in service

OTHER VALUE

Type	Description
Avoided Costs	reduces the number of false alarms and prevent resources from being sent to a site for unnecessary investigations.

Ransomware Recovery

Report Pulled: 11/1/2024 **Item ID: 11713**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Ransomware Recovery

Description This project will implement a multi-layered security approach to our production OT data center backups to mitigate data loss risk from a ransomware attack for both IT and OT.

Portfolio IT Services > Infrastructure > Data Center - Storage > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement

The company is at risk from ransomware attacks. A severe ransomware attack could leave the Company without access to critical data and unable to recover the data. In a best case scenario, a successful ransomware attack would likely result in primary systems outages for up to a week and months of work to recover remaining systems.

Objectives

The project will add value to the Company and its customers by: (1) implementing a 3-2-1-1 (3 copies, 2 media, 1 offline, 1 immutable) strategy to protect the production data center data and backups. This strategy will protect the Company from production data center data loss from a broader scope of cyber threats including ransomware. (2) Providing various restoration options to reduce data loss and improve recovery time. (3) Mitigating the risk of complete data loss with a maximum security backup to store a weekly copy of production data center data offline and in a format that cannot be changed. (4) Defining a ransomware response plan that the Company can use to respond to a wide array of cyber attacks with a practiced process. (5) Providing the ability for OT to sever all communications to the public internet and corporate IT networks.

Scope

The scope of this project is to deliver one day of hardware storage level snapshots, local immutable copies of production and OT data center data, public cloud third copy of 100% of production data center data, and a ransomware recovery plan with a scenario-based approach to ransomware response including plans for monitoring, containment, malware clean up and recovery.

Alternatives

The project team looked at a number of alternatives to provide a ransomware recovery plan including paying the ransom, using tape backup, restoring to the public cloud, and buying a third datacenter. The project team looked closely at tape backups but with Company's heavy investment in their current solution for backups and the ability of the current solution to provide immutable copies the team felt that the current solution immutability better met the requirements and at a lower cost and faster delivery. Restoration to the public cloud was considered but delivery would have been extremely complex and likely would have taken 3-5 years to get in place. Lastly the project team looked at setting up a third data center that would be used as an offline copy of production. The cost was too high and it didn't provide any value over our current public cloud and on-premise backup copies of production and OT data center data.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/4/2021	1/15/2021	2/12/2021	2/22/2021
	In-Service/Go-Live	**Closeout**	
	5/26/2023	5/30/2023	

FUNDING SUMMARY

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Cap+COR	$1.116	$0.377	$0.003	-	-	-	-	-	$1.496
O&M	$0.149	$0.208	$0.001	-	-	-	-	-	$0.358
Total Cost of Ownership	$1.265	$0.585	$0.004	-	-	-	-	-	**$1.854**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.300	$0.170	$0.003	-	-	-	-	-	**$0.473**
Outside Services	$0.016	$0.148	-	-	-	-	-	-	**$0.164**
Business Expense/Overheads	$0.105	$0.043	$0.001	-	-	-	-	-	**$0.150**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.390	$0.120	-	-	-	-	-	-	**$0.510**
Licenses, Permits & Fees	$0.454	$0.104	-	-	-	-	-	-	**$0.558**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.265	$0.585	$0.004	-	-	-	-	-	**$1.854**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2021	2022	2023	2024	2025	2026	2027	2028 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.149	$0.208	$0.001	-	-	-	-	-	**$0.358**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.149	$0.208	$0.001	-	-	-	-	-	**$0.358**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.116	$0.377	$0.003	-	-	-	-	-	**$1.496**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.116	$0.377	$0.003	-	-	-	-	-	**$1.496**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Loss of Data Center - Parnall	High	Low	This should be tied to the Data Loss Corporate Risk. This project reduces the risk by ensuring we have a secure version of production data in the event of ransomware attack.
System Failure (SAP & Other)	Low	Low	Without the full project implementation, maintenance may need to be renewed for up to $1.2M on equipment that is not currently planned in the ITPM.

OTHER VALUE

Type	Description
Technology Capability	Ransomware Recovery systems

Rate Change Maintenance

EXECUTIVE SUMMARY

Report Pulled: 11/1/2024 **Item ID: 13957**

BASIC INFORMATION

Work Category Comply - Interval **Work Type** Project

Alias Rates Case Implementation, Rate Cases Annual Upgrade Implementation, Rate Cases Annual Upgrade, Rate Case Annual Upgrade, Rate Case Annual Requirements, Rate Case Maintenance, Rate Change Maintenance

Description The Rates Change Maintenance project will modify SAP billing in accordance with pricing and rate change requirements.

Portfolio IT Services > Applications > Customer Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement For the Company to continue to meet and comply with the Michigan Public Service Commission (MPSC) rate change requirements, there is a need to make periodic updates/modifications to the existing prices and rate structures. These updates help ensure accuracy of billing and provide optimal rates for customers.

Objectives The project will add value for both the Company and its customers through: (1) improved customer satisfaction by providing accurate billing; (2) optimized rate configuration enabling rate changes to be made more efficiently; and (3) timely updates to Company applications that incorporate mandatory changes to the rate structure that includes new surcharges, price changes, and energy efficiency programs.

Scope The scope of this project encompasses (1) implementation of annual or monthly (or both) electric and gas customer price changes, and rate structure changes as approved by the MSPC; and (2) optimizing the rate configuration in the Company's back-end system for more efficient rate changes.

Alternatives An alternative considered for this effort was a fully dedicated offshore development model. The option ensured resources were readily available with a more cost-effective labor expense. This alternative was not chosen due to the risk of billing inaccuracies and customer complaints. These risks were deemed too high because of the complexities of the rate structure, new development, and the timing it would take for testing of this model. Cloud is not an applicable option in this case as we are not replacing any software. The option to use onshore resources to plan, coordinate, and execute the rate changes was selected as it supports the Company's operation model for rate changes.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.279	$0.318	$0.318	$0.318	$0.318	$0.318	-	-	$1.870
Total Cost of Ownership	$0.279	$0.318	$0.318	$0.318	$0.318	$0.318	-	-	**$1.870**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.002	$0.297	$0.297	$0.297	$0.297	$0.297	-	-	**$1.488**
Outside Services	$0.271	-	-	-	-	-	-	-	**$0.271**
Business Expense/Overheads	$0.006	$0.021	$0.021	$0.021	$0.021	$0.021	-	-	**$0.110**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost (Annual)	$0.279	$0.318	$0.318	$0.318	$0.318	$0.318	-	-	**$1.870**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.279	$0.318	$0.318	$0.318	$0.318	$0.318	-	-	**$1.870**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.279	$0.318	$0.318	$0.318	$0.318	$0.318	-	-	**$1.870**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Completing timely rate changes reduces the risk of increasing noncollectable revenue due to delays with rate implementation. The Company could risk millions of dollars if rate changes are delayed; establishing an optimized process for rate changes is crucial to mitigate this risk.
Technology Capability	Customer Management
Avoided Costs	Following the Rate Optimization implementation the team responsible for rate changes can streamline their efforts; preventing waste in the form of waiting and rework. Multiple changes can be completed at once versus sequencing them which causes rework when priorities shift.
Risk Mitigation	Maintain compliance by fulfilling MPSC rates requirements, ensuring customer bills remain accurate as the Company implements various rate changes. This will help the Company provide the best rates for customers as they're identified.

Replacement for Gas Automated Meter Reading (AMR) Tech Report Pulled: 11/1/2024 Item ID: 13960

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Condition **Work Type** Project

Alias , Field Collection Systems (FCS) and Itron Mobile Replacement, Replacement for Gas Meter Reading Technology, Replacement for Gas Automated Meter Reading (AMR) Technology

Description This project will replace Itron Field Collection Systems (FCS) and Itron Mobile with the newest Itron Software as a Service (SaaS) Temetra along with replacing Itron Mobile with Temetra Mobile for Gas AMR meters. This will allow the Company to leverage new cloud capabilities and align with the Company's Cloud strategy.

Portfolio IT Services > Applications > Gas Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement The Company is using FCS and FCS mobile to gather gas meter reads. The vendor is replacing these systems with new Cloud software called Temetra and Temetra Mobile due to FCS and Itron Mobile being end of life December 2026. The software migration is necessary to maintain vendor support (latest security patches, bug fixes, latest functionality) while avoiding security, stability, and reliability risks for the Company. Moving to Itron Temetra will ensure no gas meter reading disruption and continued integration with existing gas communication modules and Itron Security Manager.

Objectives The project adds value by: (1) continuing to collect accurate and timely gas meter reads; (2) removing the risk of being on unsupported versions; (3) utilizing the latest functionality such as retrieving historic read data, photos and reports directly from Temetra; (4) seamlessly getting up to date security patches; (5) and reducing ongoing networking equipment replacement and upgrade costs.

Scope Included in the implementation is: (1) configuring and deploying Temetra and Temetra Mobile; (2) migrating data; (3) integrating to Itron Enterprise Edition (IEE), Itron Security Manager (ISM), gas AMR PI Historian and Data Lake; (4) integrating to Mobile Collectors (MC3s); (5) testing the software, data migrations and integrations; (6) educating and increasing the skills of the employees to leverage the new cloud services; (7) and decommissioning FCS and Itron Mobile and the on-premise databases and servers.

Alternatives Alternatives considered included: (1) continuing to use the FCS application and Itron Mobile without vendor support. This alternative was not selected because it would add application stability, security, and dependency risks to gas meter reading data collection which would negatively impact critical customer billing operations. It would also de-couple from the Itron security infrastructure that the other business critical Itron applications use, creating more expense and complexity in the technology environment. (2) Replace the platform with a different mobile gas reading application, which would also require the Company to replace the 1.2 million gas communication modules on the meters. Replacing FCS would require the application business owners to undertake a large initiative requiring multiple years to implement and a multi-team effort from start to finish. It would also increase the amount of technology needed to be supported and add cost to support as it would be a standalone product. (3) Move to Itron's Cloud technology (Temetra and Temetra Mobile). This option best suits customers and the Company's needs for the future as it offers new functionality while maintaining the system integrated into the Itron Security infrastructure and with the other Itron software products in use at the Company.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/12/2026	1/26/2026	2/26/2026	7/30/2026
	In-Service/Go-Live	**Closeout**	
	9/24/2026	10/15/2026	

FUNDING SUMMARY

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Cap+COR	$1.028	-	-	-	-	-	-	-	$1.028
O&M	$0.277	-	-	-	-	-	-	-	$0.277
Total Cost of Ownership	$1.304	-	-	-	-	-	-	-	**$1.304**

	2026	2027	2028	2029	2030	2031	2032	2033 +	Total
Labor	$0.209	-	-	-	-	-	-	-	**$0.209**
Outside Services	$0.063	-	-	-	-	-	-	-	**$0.063**
Business Expense/Overheads	$0.065	-	-	-	-	-	-	-	**$0.065**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.803	-	-	-	-	-	-	-	**$0.803**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.140	-	-	-	-	-	-	-	**$1.140**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2026	2027	2028	2029	2030	2031	2032	2033 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.277	-	-	-	-	-	-	-	**$0.277**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.277	-	-	-	-	-	-	-	**$0.277**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.028	-	-	-	-	-	-	-	**$1.028**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.028	-	-	-	-	-	-	-	**$1.028**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Gas T&D
Intangibles	Latest software of Temetra enables the best integration with other Itron products, such as future versions of Itron Security Manager. Failure to stay current, will impact the upgradability of the entire Itron software suite as well as gas meters from gas-only customers.
Intangibles	The Company has adopted a cloud-first policy. The move from FCS to Temetra will align with that policy.
Intangibles	This project will assist in improving performance of the platform through bug fixes and performance tuning and latest enhancements. Ensuring the Company is on the latest platform will enhance usability while also guaranteeing it is running the most secure configuration.
Risk Mitigation	To mitigate the risks of software reaching end-of-life, we need to transition to this new, supported solution. Temetra and Temetra mobile are essential to ensure vendor support with the latest security patches, bug fixes and latest functionality.
Avoided Costs	With applications in the cloud, the Company can reduce it's purchasing of on-premise servers and on-premise software

SAP Data Archiving

EXECUTIVE SUMMARY

Report Pulled: 11/1/2024 **Item ID: 6831**

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias SAP Archiving,SAP Data Archiving

Description This project will move outdated data from an online database to offline storage.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement The SAP Enterprise Resource Planning Central Component database is 37 terabytes in size and growing at a rate of 0.3 terabytes to 0.5 terabytes per month. If the database is not archived, then SAP system performance will degrade, and this will affect customers and employees who are completing tasks within the system.

Objectives This project will create value for the Company by: (1) increasing system stability by controlling online data storage levels; and (2) controlling maintenance costs associated with data storage. Annual data storage costs are $7,445 per terabyte only including the primary production system. Data back-up costs are $400 per terabyte per week for full back-ups.

Scope The project scope includes: (1) archiving data based on the fastest growing and largest archiving objects in SAP (an archiving object defines the structure and context of the data in the SAP database from an archiving perspective); (2) building and archiving solutions that allow retrieval of archived data in the required form; and (3) setting up a solution that meets compliance standards.

Alternatives Three alternatives were explored and determined non-viable for the project: (1) allow the database to continue to grow, which puts system performance at risk and results in prohibitive storage costs; (2) decrease the overall scope and archive fewer objects, which would result in minimal positive impact to system growth and significant storage-related costs; and (3) increase the scope and archive more objects in a shorter timeframe, which would result in a significant cost increase over shorter time period. After considering each of these options, it was determined that the current scope of the project was the best strategy to address the problem while balancing annual spending.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2025	4/1/2025	6/1/2025	7/1/2025
	In-Service/Go-Live	**Closeout**	
	10/15/2025	10/31/2025	

FUNDING SUMMARY

	2019	2020	2021	2022	2023	2024	2025	2026 +	Total
Cap+COR	$0.106	$(0.028)	$(0.004)	$0.657	$0.021	-	-	-	$0.752
O&M	$0.031	$0.176	$0.031	$0.462	$0.002	-	-	-	$0.702
Total Cost of Ownership	$0.137	$0.148	$0.027	$1.119	$0.023	-	-	-	**$1.454**

	2019	2020	2021	2022	2023	2024	2025	2026 +	Total
Labor	$0.137	$0.146	$0.028	$0.080	-	-	-	-	**$0.391**
Outside Services	-	-	-	$0.951	$0.004	-	-	-	**$0.955**
Business Expense/Overheads	-	$0.002	$(0.001)	$0.088	$0.019	-	-	-	**$0.108**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	**-**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost	$0.137	$0.148	$0.027	$1.119	$0.023	-	-	-	**$1.454**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2019	2020	2021	2022	2023	2024	2025	2026 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.031	$0.176	$0.031	$0.462	$0.002	-	-	-	**$0.702**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.031	$0.176	$0.031	$0.462	$0.002	-	-	-	**$0.702**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	$0.106	$(0.028)	$(0.004)	$0.657	$0.021	-	-	-	**$0.752**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	$0.106	$(0.028)	$(0.004)	$0.657	$0.021	-	-	-	**$0.752**
Revenue	Reduction	-	-	-	-	-	-	-	-	**-**
	Initial	-	-	-	-	-	-	-	-	**-**
	Incremental	-	-	-	-	-	-	-	-	**-**
	Net	-	-	-	-	-	-	-	-	**-**

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
System Failure (SAP & Other)	High	Medium	If the SAP database is not archived, the system performance will degrade over time, negatively impacting customer experience and preventing employees from completing transactions within acceptable performance thresholds. Additionally, at current growth rate, the Enterprise Central Component (ECC) database could potentially run out of storage space.

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Maintain the data growth rate for SAP ECC (Enterprise Central Component) under 0.4 terabytes per month.
Risk Mitigation	Through data archiving, the size of the SAP ECC (Enterprise Central Component) database is kept in check allowing SAP to perform at an optimal level.

SAP HANA Database Migration

Report Pulled: 11/1/2024 **Item ID: 11774**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , SAP HANA Database Migration

Description In preparation for SAP's planned end of support for its Business Suite product in 2027, the Company will migrate its existing SAP databases from Oracle to SAP HANA in advance of the required move to S/4HANA.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement

The Company's SAP applications currently utilize Oracle's relational database management system as their underlying database storage technology. SAP has informed its customers that standard support for its legacy Business Suite (aka ECC) product will end in 2027, along with support for all non-SAP database platforms. SAP has also informed customers that the future direction for their enterprise solution is S/4HANA, a solution built explicitly for their HANA database platform. To prepare for these upcoming events, the company will migrate all of its SAP databases off of Oracle and onto SAP HANA.

Objectives

This project lays the groundwork for the company's eventual shift to SAP's HANA-based solutions by: (1) proactively migrating SAP databases to a database technology that is fully supported by SAP beyond 2027; and (2) mitigating the risk of a complete loss of support for the current Oracle database technology in 2027.

Scope

Project scope includes: (1) procurement of HANA software licensing to cover all migrated SAP applications; (2) data migration for all SAP applications from the Oracle database to SAP HANA; and (3) implementation of new application support policies, procedures and tools required to manage the newly migrated SAP HANA applications.

Alternatives

Given SAP's announcement regarding the end of support for its ECC product in 2027, all customers running SAP on database software other than HANA will also lose support for their associated database software in 2027. SAP is offering no other options for databases other than HANA beyond 2027. While there is no alternative to the HANA database for SAP going forward, the Company has considered multiple options: (1) Perform a direct migration from SAP Business Suite on Oracle to S/4HANA. A direct migration to S/4HANA brings greater operational risk to the Company as both the underlying database technology and the SAP application's functionality would change simultaneously, so this alternative was not selected. (2) Remain on the current SAP Business Suite product but competitively bid support services to a third-party provider instead of SAP. This alternative was not selected because moving to a third-party support model forces the Company to remain on outdated SAP software and eliminates any possibility of benefitting from new business functionality provided by S/4HANA. It will also require the Company to accept significant risk due to the fact that SAP security patches, application patches and upgrades will not be available upon termination of the SAP maintenance agreement. (3) Migrate to SAP's Software as a Service (SaaS) implementation of S/4HANA. This alternative was not selected because an S/4HANA SaaS migration is a much more disruptive option as the Company's business processes must be adjusted to accommodate functionality differences between ECC and S/4HANA. The risk of negative business impact is significantly greater than simply changing the underlying database technology. (4) Migrate the SAP databases to HANA prior to implementing S/4HANA. This alternative was selected as it gives the Company several years to solidify its HANA database infrastructure before introducing the substantial business process changes required with S/4HANA.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
7/3/2023	7/31/2023	10/2/2023	1/2/2024
	In-Service/Go-Live	**Closeout**	
	11/1/2025	12/2/2025	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$2.392	$2.413	$1.686	-	-	-	-	-	$6.491
O&M	$0.181	$0.761	$0.411	-	-	-	-	-	$1.353
Total Cost of Ownership	$2.572	$3.174	$2.097	-	-	-	-	-	**$7.844**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.101	$0.382	$0.341	-	-	-	-	-	**$0.825**
Outside Services	$0.180	$2.134	$1.489	-	-	-	-	-	**$3.803**
Business Expense/Overheads	$0.035	$0.276	$0.267	-	-	-	-	-	**$0.578**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$2.255	$0.382	-	-	-	-	-	-	**$2.637**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$2.572	$3.174	$2.097	-	-	-	-	-	**$7.844**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	$(1.096)	$(1.096)	-	-	-	**$(2.192)**
	Initial	$0.181	$0.761	$0.411	-	-	-	-	-	**$1.353**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.181	$0.761	$0.411	$(1.096)	$(1.096)	-	-	-	**$(0.839)**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$2.392	$2.413	$1.686	-	-	-	-	-	**$6.491**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$2.392	$2.413	$1.686	-	-	-	-	-	**$6.491**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.784

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	By completing this work in advance of December 2027, when SAP will cease support of its Business Suite (ECC) product, and by performing this work in a phased approach (migrating to HANA database first, before migrating the application to S/4HANA), the Company avoids potential operational stability issues.
Technology Capability	SAP is eliminating support for all databases other than HANA beginning in 2027. By migrating to HANA in advance of this 2027 date, the Company is able to eliminate its reliance on Oracle's database software and move to SAP's long-term database solution, HANA.

REDACTED

SAP S/4HANA Implementation

SAP Support Pack Upgrade 2023-2024

Report Pulled: 11/1/2024 **Item ID: 12500**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , SAP Support Pack Upgrade 2023, SAP Support Pack Upgrade 2024, SAP Support Pack Upgrade 2023-2024

Description The SAP Support Pack Upgrade project is to maintain the currency levels of all SAP applications. This will ensure the applications are at version levels that are supported by SAP, have the latest patches and bug fixes, and provide cross-application compatibility for our business partners.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement To continue to maintain SAP application version currency, across all applications, the support packs released by SAP must be routinely applied. Without maintaining application currency, the core business applications running on the SAP platform are at risk of losing vendor support, resulting in the inability to apply bug fixes and patches, including security patches, and maintain application interoperability and stability.

Objectives The project will add value by: (1) maintaining supportability of SAP applications; (2) mitigating system security, stability and reliability risks by ensuring the applications are up-to-date with the most current patches and bug fixes released by SAP; and (3) ensuring ongoing cross-application compatibility.

Scope The scope of this project includes routine support pack upgrades to all SAP applications, which include: Enterprise Core Component (ECC), Customer Relationship Manager (CRM), Enterprise Portal, Process Orchestration (PO), Business Warehouse (BW), Business Objects (BOBJ), Data Services (DS), Governance, Risk and Compliance (GRC), Solution Manager, Data Quality Manager (DQM), Graphical User Interface (GUI), Single Sign On (SSO), System Landscape Directory (SLD) and other related SAP applications.

Alternatives Alternatives considered include: (1) Divide the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) Migrate to SAP S/4HANA. This option was not selected at this time because it is part of the long-term digital plan and requires substantial planning and investment, (3) Balance the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimizing cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2024	4/1/2024	6/1/2024	7/1/2024
	In-Service/Go-Live	**Closeout**	
	10/15/2024	10/31/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.010	$0.159	-	-	-	-	-	-	$0.169
Total Cost of Ownership	$0.010	$0.159	-	-	-	-	-	-	**$0.169**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.001	$0.007	-	-	-	-	-	-	**$0.008**
Outside Services	$0.009	$0.145	-	-	-	-	-	-	**$0.154**
Business Expense/Overheads	$0.001	$0.007	-	-	-	-	-	-	**$0.007**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.010	$0.159	-	-	-	-	-	-	**$0.169**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.010	$0.159	-	-	-	-	-	-	**$0.169**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.010	$0.159	-	-	-	-	-	-	**$0.169**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Ensure all SAP applications are compatible with each other.
Intangibles	Ensure all SAP applications are fully supported by SAP.
Risk Mitigation	Risk mitigation against system and information security related issues by ensuring that all the SAP applications have the latest patches and bug fixes.

SAP Support Pack Upgrade 2026

Report Pulled: 11/1/2024 **Item ID: 12501**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , SAP Support Pack Upgrade 2025, SAP Support Pack Upgrade 2026

Description The SAP Support Pack Upgrade project is to maintain the currency levels of all SAP applications. This will ensure the applications are at version levels that are supported by SAP, have the latest patches and bug fixes, and provide cross-application compatibility for our business partners.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement To continue to maintain SAP application version currency, across all applications, the support packs released by SAP must be routinely applied. Without maintaining application currency, the core business applications running on the SAP platform are at risk of losing vendor support, resulting in the inability to apply bug fixes and patches, including security patches, and maintain application interoperability and stability.

Objectives The project will add value by: (1) maintaining supportability of SAP applications; (2) mitigating system security, stability and reliability risks by ensuring the applications are up-to-date with the most current patches and bug fixes released by SAP; and (3) ensuring ongoing cross-application compatibility.

Scope The scope of this project includes routine support pack upgrades to all SAP applications, which include: Enterprise Core Component (ECC), Customer Relationship Manager (CRM), Enterprise Portal, Process Orchestration (PO), Business Warehouse (BW), Business Objects (BOBJ), Data Services (DS), Solution Manager, Data Quality Manager (DQM), Graphical User Interface (GUI), Single Sign On (SSO), System Landscape Directory (SLD) and other related SAP applications.

Alternatives Alternatives considered include: (1) Divide the scope into individual projects by SAP application. This alternative was not selected because the efforts are interrelated and completing them separately could lead to duplication of work, especially testing efforts, and therefore potentially higher costs. (2) Migrate to SAP S/4HANA. This option was not selected, because SAP S/4HANA is a multi-year project that is not expected to be completed by year-end 2026. So an alternative approach is needed to perform the application upgrades and maintain currency in the meantime. (3) Balance the project scope through regular support pack upgrades. This alternative was selected because it provides the best balance of minimizing cost and maintaining support by combining multiple application upgrades through a single support pack upgrade effort.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2026	4/1/2026	6/1/2026	7/1/2026
	In-Service/Go-Live	**Closeout**	
	10/15/2026	10/31/2026	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	$1.087	-	-	-	$1.087
Total Cost of Ownership	-	-	-	-	$1.087	-	-	-	**$1.087**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	-	-	-	-	$1.015	-	-	-	**$1.015**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	-	-	-	-	$0.071	-	-	-	**$0.071**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	-	-	-	$1.087	-	-	-	**$1.087**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	$1.087	-	-	-	**$1.087**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	$1.087	-	-	-	**$1.087**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Intangibles	Ensure all SAP applications are compatible with each other.
Intangibles	Ensure all SAP applications are fully supported by SAP.
Risk Mitigation	Risk mitigation by ensuring all SAP applications have the latest patches and bug fixes.

Saviynt EIGA Implementation

Report Pulled: 11/1/2024 **Item ID: 13302**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Access Now Upgrade 2023, Access Now Upgrade 2024, Saviynt EIGA Implementation, Saviynt Enterprise Identity Governance and Access (EIGA) Implementation

Description The project will implement Saviynt EIGA module, consolidate Identity Access Management (IAM) functionality into Saviynt, and retire the Identity Manager application. By implementing the new solution, the Company will optimize IAM functionality, eliminate complexity, and reduce support costs. In addition, the project will integrate the OT network with an IAM solution that will allow for automated management of users and entitlements in the OT Active Directory domains and applications.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STANI

WORK OBJECTIVES

Problem Statement The current version of AccessNow reached end-of-life in December 2022, with support discontinued in January 2023. The application has numerous custom workflows and integrations, requiring professional services for ongoing use and changes. It lacks proper data analytics and reporting, posing risks such as inability to fix critical defects, software incompatibility, compliance issues, increased costs, and degraded performance. The Company uses multiple IAM tools, each performing critical functions, leading to numerous required interfaces and customizations. While beneficial for end users, these integrations increase the risk of system failures, higher support costs, multiple subscriptions, infrastructure and maintenance costs, and more expensive upgrades. The current solution utilizes SAP HR batch file processes that introduces failure points, delays, and data integrity issues. Failures in these processes can prevent new or transferred employees from accessing necessary systems, leading to operational disruptions and potential compliance risks due to inappropriate access retention.

Objectives This project provides value by: (1) Consolidating multiple IAM platforms through the implementation of the Saviynt Enterprise IGA Module, reducing complexity and support costs; (2) Decreasing complexity and enhancing efficiency by reducing interfaces between multiple identity tools; (3) Improving the end-user experience and reducing human struggle with access requests through a new, intuitive portal design; (4) minimizing custom code and focusing on configurations only by utilizing out-of-the-box functionality; and (5) Streamlining employee data processing with the implementation of an HR interface.

Scope This project scope includes: (1) Implementing the Saviynt EIGA module to consolidate IAM platforms; (2) Standardizing processes by removing customized code and using out-of-the-box functionality; (3) Replacing and improving access system; (4) Addressing issues with aging applications, multiple IAM platforms, integration challenges, and antiquated HR processing.

Alternatives Alternatives considered include: (1) Implementing hot fixes to AccessNow version 8.1.5 to ensure support through mid-2023; (2) Upgrading only the application to current supported version, excluding the new web portal but will including new application functionality; (3) Remaining on current version that will be unsupported as of January 2023, requiring vendor professional services for any break / fix. Patches and enhancements may potentially introduce additional risk of version instability; (4) Implementing IAM functions in Saviynt platform to manage access requests, including Active Directory, SAP, SAP HR, disconnected systems, and existing API integrations. The alternative selected was implementing the new Saviynt system, eliminating AccessNow software.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
3/1/2024	4/5/2024	6/15/2024	8/1/2024
	In-Service/Go-Live	**Closeout**	
	5/29/2026	6/30/2026	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	$3.066	$1.900	$0.947	-	-	-	-	-	$5.913
O&M	$0.200	$0.450	$0.443	$0.765	$0.765	$0.765	-	-	$3.388
Total Cost of Ownership	$3.266	$2.351	$1.389	$0.765	$0.765	$0.765	-	-	**$9.302**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	$0.475	$0.449	$0.198	-	-	-	-	-	**$1.121**
Outside Services	$0.989	$1.100	$0.600	-	-	-	-	-	**$2.689**
Business Expense/Overheads	$0.203	$0.702	$0.159	-	-	-	-	-	**$1.064**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.100	$0.050	-	-	-	-	-	**$0.150**
Licenses, Permits & Fees	$1.600	-	-	-	-	-	-	-	**$1.600**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$3.266	$2.351	$1.007	-	-	-	-	-	**$6.624**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.200	$0.450	$0.443	$0.765	$0.765	$0.765	-	-	**$3.388**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.200	$0.450	$0.443	$0.765	$0.765	$0.765	-	-	**$3.388**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$3.066	$1.900	$0.947	-	-	-	-	-	**$5.913**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$3.066	$1.900	$0.947	-	-	-	-	-	**$5.913**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	Administrative and General (A&G) Support

Security Threat Intelligence Tool

Report Pulled: 11/1/2024 **Item ID: 13875**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Security Threat Intelligence Tool

Description This project will implement a threat intelligence application that will actively assess physical and cyber threats in the environment, visually display historical and active threat data for situational awareness and provide alerts to employees based on location of the threat. This information will allow the Company's combined physical and cyber security operations center (Fusion Center) to alert employees who are in the proximity of a physical threat on the risks they may face, help inform decisions on hardening facility locations and alert employees of active cyber threats that are currently impacting other companies. The ability to proactively alert employees of the threats will have a positive impact on Safety and Cyber Security for the Company by reducing response time to incidents and reduce the likelihood an employee will be physically injured.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-CYBER SEC ENG & STAN

WORK OBJECTIVES

Problem Statement The Company's Fusion Center and Physical Security teams currently do not have the ability to actively collect or disseminate threat intelligence in real time. This gap in technology increases the risk of physical and cyber crime to employees and company assets. As the threat landscape changes, automating data collection is essential to detecting and determining threats in real time. Currently the Company's Fusion Center manually searches through sources to collect threat intelligence. The data that is manually collected is often out of date by up to one week. This re-active approach has led to gaps in information and the inability to accurately depict the threat environment. Relying on manual processes and stale data results in employees to be put in life threatening situations. Cyber threats change daily in the environment. Spending valuable time to search manually through threat information causes delays in protecting the Company's sensitive data including electric and gas critical infrastructure, financial and customer data.

Objectives This project creates value for the Company by: (1) Implementing a threat intelligence tool that actively assesses threats in the environment; (2) Visually displaying historical and active threat data for situational awareness; and (3) Providing alerts to co-workers based their location. Accurate and timely information about threat actors and their tactics enables the team to proactively perform targeted investigation, containment, and remediation.

Scope The project scope includes: (1) Implementing a single threat intelligence application that will provide intel on both physical and cyber threats; (2) Integrating with the current security orchestration platform; and (3) Building automation to notify co-workers of physical threats that are identified through intel provided in the application.

Alternatives Alternatives considered include: (1) Maintaining the Company's current security posture of manually gathering information on threats through social media, law enforcement and news reports. Continue to alert employees of active threats once they are noticed by Fusion Center employees. This alternative was not selected because the process to gather the data is completely manual and the data gathered can be outdated by up to a week. Stale data can put company assets and employees in dangerous situations. Using outdated information delays response time for company crews and law enforcement to address the situation. (2) Expanding the Company's current mass notification tool use to integrate security threat intelligence intel. This alternative was not selected due to the risk of delayed response time to receive threat notification from the current vendor in comparison to other vendors in the market. (3) Building an in-house threat intelligence application to fulfill the security threat intel requirements. This alternative was not selected because developing security platforms of this type is not in the core competences of the Company. The Company's resources don't have access to the wide range of threat data that other companies leverage to develop a threat intelligence application. In addition, the cost to maintain an in-house application of this type would not be economically practical. (4) Implementing a threat intelligence application that meets the Company's security threat intelligence requirements. This alternative was selected.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/7/2026	5/30/2026	7/31/2026	2/27/2027
	In-Service/Go-Live	**Closeout**	
	2/27/2027	3/27/2027	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	-	$0.728	$0.135	-	-	-	-	-	$0.864
O&M	-	$0.103	$0.021	-	-	-	-	-	$0.124
Total Cost of Ownership	-	$0.831	$0.157	-	-	-	-	-	**$0.988**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	-	$0.145	$0.074	-	-	-	-	-	**$0.219**
Outside Services	-	$0.050	$0.050	-	-	-	-	-	**$0.100**
Business Expense/Overheads	-	$0.181	$0.033	-	-	-	-	-	**$0.214**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.455	-	-	-	-	-	-	**$0.455**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$0.831	$0.157	-	-	-	-	-	**$0.988**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.103	$0.021	-	-	-	-	-	**$0.124**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.103	$0.021	-	-	-	-	-	**$0.124**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.728	$0.135	-	-	-	-	-	**$0.864**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.728	$0.135	-	-	-	-	-	**$0.864**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Alert employees who are in the proximity of a physical threat on the risks they may face, help inform decisions on hardening facility locations and alert employees of active cyber threats that are currently impacting other companies.
Technology Capability	Automatically pull and aggregate external threat information and Open Source Intelligence (OSINT) from disparate sources into a single source
Technology Capability	The application will provide a single interface with high-quality intel feeds that the Company's Cyber Security Incident Response Team (CSIRT) monitors as part of its operational duties.
Technology Capability	The Company's physical security area will benefit from the project by receiving accurate and timely information about threat actors and their tactics enables the security team to proactively perform targeted investigation, containment, and remediation.
Technology Capability	Threat intel information sources will be filtered for context and relevance to the Company.

Security/OT Field Modernization

Report Pulled: 11/1/2024 **Item ID: 13949**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Security/OT Field Modernization

Description This project will implement new infrastructure for accomplishing improved security in the field for OT assets.

Portfolio IT Services > Infrastructure > * > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement Gas and Electric technicians are using corporate laptops, to manage critical OT infrastructure which does not follow cyber security best practices for managing critical infrastructure. Vendors and contractors have access to the Company's critical infrastructure using non-company laptops. Best practice is to use dedicated laptops to connect to critical infrastructure.

Objectives The value of this project is deploying dedicated company OT laptops and associated OT infrastructure that can move between OT locations only and providing a secure environment.

Scope This project will procure and configure approximately 130 devices that will be used to manage critical OT infrastructure.

Alternatives The Company reviewed several options to mitigate cyber security risks inherent with the use of standard corporate laptops managing critical infrastructure. The alternatives considered are: (1) Continue utilizing existing workflow of using Corporate domain laptops with software installed; (2) Bring in an outside vendor to design and implement a proposed infrastructure; (3) Considered complete disallowance of all local access to critical systems; (4) Consider extending the OT network to remote Company locations; (5) Deploy a dedicated company OT laptop and OT communications circuits, which includes cellular connectivity. The dedicated OT laptop and communications circuits presented the best way to secure the critical infrastructure by limiting internet and e-mail access. Vendors and contractors could also utilize these approved dedicated systems for managing infrastructure they help support at Company locations. Based on the analysis performed, the Company chose to deploy a dedicated OT laptop and communications circuits.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/13/2025	3/7/2025	4/30/2025	5/30/2025
	In-Service/Go-Live	**Closeout**	
	3/1/2026	6/1/2026	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.835	$0.326	-	-	-	-	-	-	$1.162
O&M	$0.243	$0.314	$0.294	$0.294	$0.294	-	-	-	$1.438
Total Cost of Ownership	$1.078	$0.640	$0.294	$0.294	$0.294	-	-	-	**$2.600**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.341	$0.125	-	-	-	-	-	-	**$0.467**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.370	$0.168	-	-	-	-	-	-	**$0.538**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.285	$0.123	-	-	-	-	-	-	**$0.408**
Licenses, Permits & Fees	$0.035	$0.020	-	-	-	-	-	-	**$0.055**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.031	$0.436	-	-	-	-	-	-	**$1.467**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.243	$0.314	$0.294	$0.294	$0.294	-	-	-	**$1.438**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.243	$0.314	$0.294	$0.294	$0.294	-	-	-	**$1.438**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.835	$0.326	-	-	-	-	-	-	**$1.162**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.835	$0.326	-	-	-	-	-	-	**$1.162**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	By utilizing dedicated Operational Technology (OT) laptops without internet or e-mail access, we are mitigating the risk of a device with internet and e-mail access compromising the critical infrastructure at various Electric and Gas sites while connecting to critical control systems.
Risk Mitigation	Mandating vendors to use a dedicated Consumers Energy devices to connect to CE industrial infrastructure mitigates risk to critical systems from unknown and untrusted devices.
Intangibles	There could be impacts to business services, customer service, and Company reputation.

Self Service Vendor Portal

Report Pulled: 11/1/2024 **Item ID: 13942**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Supplier Portal for Invoice Management, Vendor Portal, Self Service Vendor Portal

Description The work will create an external portal for vendors to exercise self-service features to streamline and automate purchase order and invoice management and improve visibility to invoice and payment status.

Portfolio Corporate Services > Financial Services > Controller > General Accounting > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement

For Accounts Payable, vendors must repeatedly interact with the Company through multiple channels to ask questions, submit invoices, or check invoice or payment status, including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates, to make payments, or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for vendor invoice and payment management and lacks the ability for vendors to utilize touchless invoice creation from POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes 6 contracted resources, and creates the potential for late payments or missing early payment discounts. For Supply Chain, vendors must repeatedly interact with the Company through multiple channels to ask questions, update POs (quantities, costs, shipping dates) including email, physical mail, or the phone. Once a request is submitted, additional calls, emails, or Company portal requests are required for status updates or to respond to missed contacts. The existing service portal has functionality limited to incoming vendor inquiries only and lacks self-service options for updates to the POs. The limitations of the existing portal result in waste and inefficiencies for vendors and Company employees/contractors, which currently includes 4 employee resources. This also creates the potential for late payments, missing early payment discounts, delays in receiving due to lack of shipping notifications from vendors, delays to scheduled work due to lack of acknowledgement and lead time adherence, and the inability to enforce contractual obligations.

Objectives

This project creates value for the Company by: (1) creating self-service functionality/increasing touchless invoice creation/processing that allows the vendor to select items from a purchase order to create an invoice on demand; (2) providing vendors with real-time invoice and payment status, increasing employee productivity by eliminating waste (3) allow self-service updates of vendor master data (banking info, remittance info, etc.) (4) fewer late payments by vendors thus reducing Company follow up and tracking; (5) creating better visibility for vendors to take advantage of early payment discounts thus reducing related vendor inquiries; (6) reducing vendor questions related to invoice and purchase orders through self-service functions and portal information; (7) reducing the cost per invoice; (8) creating self-service functionality/increasing touchless PO creation/processing that allows the vendor to select items from a purchase order to update quantities, costs, and shipping dates; (9) providing vendors with real-time PO information, increasing employee productivity by eliminating waste; and (10) fewer late deliveries by vendors thus reducing Company follow up and tracking.

Scope

The project scope includes: (1) submit an RFP for a vendor portal solution and implementation; (2) configure ability for vendors to more efficiently and more accurately self-submit invoices and POs electronically; (3) configure ability for vendors to self-convert items on a purchase order to an invoice; (4) configure ability for vendors to view invoice and payment status; (5) configure ability for vendors to make changes to SAP master data, including PO line item details; (6) configure ability to offer/process dynamic discounting (7) create new reports and dashboards; (8) enabling method to validate vendors should have access to the portal and removing access when appropriate; (9) configure ability for vendors to make self-serve changes to shipping status and delivery dates; and (10) integration to vendor invoice management system and SAP.

Alternatives

Alternatives considered include: (1) Continue use of the current manual processes which results in waste and inefficiencies for employees and vendors. This could also result in late payments and lost discounts for vendors; (2) Build a custom solution. This option was not selected as the Company has a vendor portal, that is only leveraged for vendors to ask questions. As well, it doesn't leverage best practices; (3) Building a combination of custom and standard integration to existing solutions. This option was not selected because it doesn't follow industry best practices; (4) expand our current vendor portal. This option was not chosen due to limited functionality and not matching capability roadmaps; and (5) implement a new SaaS solution specific to a vendor portal experience. Option (5) is the preferred option because it leverages industry best practices with a proven solution; provides application reliability, security, and stability through ongoing vendor support; and brings innovation to vendors via real-time processing.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
9/1/2025	3/1/2026	5/1/2026	7/1/2026
	In-Service/Go-Live	**Closeout**	
	8/1/2026	8/15/2026	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	-	$0.135	-	-	-	-	-	$0.135
O&M	-	-	$0.128	$0.575	$0.575	$0.575	-	-	$1.855
Total Cost of Ownership	-	-	$0.263	$0.575	$0.575	$0.575	-	-	**$1.989**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	-	$0.175	$0.032	$0.032	$0.032	-	-	**$0.271**
Outside Services	-	-	$0.080	$0.080	$0.080	$0.080	-	-	**$0.320**
Business Expense/Overheads	-	-	$0.008	$0.008	$0.008	$0.008	-	-	**$0.034**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	$0.450	$0.450	$0.450	-	-	**$1.350**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	-	$0.263	$0.570	$0.570	$0.570	-	-	**$1.974**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	-	$(1.056)	$(1.056)	$(1.056)	$(1.056)	-	-	**$(4.222)**
	Initial	-	-	$0.128	$0.575	$0.575	$0.575	-	-	**$1.855**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	$(0.927)	$(0.480)	$(0.480)	$(0.480)	-	-	**$(2.368)**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	$0.135	-	-	-	-	-	**$0.135**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	$0.135	-	-	-	-	-	**$0.135**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	1.126

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Technology Capability	Advanced Shipping Notice - Automated error handling / issue resolution workflow
Risk Mitigation	Advanced Shipping Notice - Automated error handling / issue resolution workflow - reduces incorrect information, introduces better governance over Advanced Shipping Notices
Intangibles	Advanced Shipping Notice - Automated open PO detail listing for notice: PO number, item numbers, item description, price, quantity, delivery date, shipping address - not currently experienced functionality
Risk Mitigation	AP Automation & Reporting - Ability to Assign Dates to Proper Fields (Contract Term Compliance)
Risk Mitigation	AP Automation & Reporting - Accrual Reporting
Intangibles	AP Automation & Reporting - Contract/PO based E-Invoicing via Portal - better decisions with quicker reporting
Intangibles	AP Automation & Reporting - Front End Duplicate & Error Checking - meeting accuracy metrics
Risk Mitigation	AP Automation & Reporting - Invoices are visible & retrievable from within SAP
Intangibles	AP Automation & Reporting - PO Flip: Immediate invoice creation - reduces time and costs per invoice
Intangibles	Automated SAP system update - PO - decreases manual entries/changes
Intangibles	Improved vendor relations due to self-service features: providing real-time and customized invoices and providing visibility for vendor discounts.

Additional 'Other Value' statement(s). Open BPS to view

Service Suite Upgrade

Report Pulled: 11/1/2024 **Item ID: 6837**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias Service Suite Upgrade

Description The project will: (1) implement a new version of Service Suite Work Management that allows for easier distribution of work orders to the field; and (2) maintain a current version on a vendor supported platform for this critical enterprise application used across Operations and Engineering.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-ELECTRIC

WORK OBJECTIVES

Problem Statement The Service Suite Application is the mission critical work management software delivering work orders for customers. The current solution lacks an integrated view of traffic and a readable dispatch work schedule. The upgrade will improve application deployment to field devices and keep the application current to maintain vendor support.

Objectives The project will add value by: (1) implementing a new version that provides the appropriate level of vendor support for this 24x7 critical solution that provides over 100,000 work orders to the field weekly; (2) implementing Service Suite Workforce Management and migrating to cloud-based configurations that will simplify support and speed deployment of future changes; (3) providing the new feature of live traffic display on the Dispatch Application which will allow for better dispatch decision making; and (4) improving the readability and usability of the Dispatch Application schedule view, which will allow for a better understanding of employees' work schedule.

Scope The scope of the project includes: (1) implementing the new version of Service Suite Workforce Management; and (2) integrating to a mobile mapping and driving directions application with Service Suite for mobile mapping on the field device to improve safety, response, usability, and supportability of the system.

Alternatives The alternatives considered included: (1) remaining on the current Service Suite version, which requires additional manual steps in the emergency response and work assignment; (2) creating a custom-developed solution, which increases waste and inefficiency, without the same level of Enterprise Resource Planning integration; or (3) changing the current vendor, which was not selected due to the increased complexity of migration and organizational change management. Upgrading Service Suite Field Service Management was chosen because it allows the Company to stay on the supported and familiar platform already being used in the field and provides additional business value and benefits to operations.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/2/2023	1/31/2023	2/28/2023	12/13/2023
	In-Service/Go-Live	**Closeout**	
	12/14/2023	12/31/2023	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$1.077	-	-	-	-	-	-	-	$1.077
O&M	$0.103	-	-	-	-	-	-	-	$0.103
Total Cost of Ownership	$1.181	-	-	-	-	-	-	-	**$1.181**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.351	-	-	-	-	-	-	-	**$0.351**
Outside Services	$0.666	-	-	-	-	-	-	-	**$0.666**
Business Expense/Overheads	$0.164	-	-	-	-	-	-	-	**$0.164**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.181	-	-	-	-	-	-	-	**$1.181**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.103	-	-	-	-	-	-	-	**$0.103**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.103	-	-	-	-	-	-	-	**$0.103**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.077	-	-	-	-	-	-	-	**$1.077**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.077	-	-	-	-	-	-	-	**$1.077**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	Medium	High	Vendor support for this application is required to run the latest version so that appropriate patches and software versioning can be applied in a safe and timely manner.

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Risk Mitigation	Critical application is unsupported by the vendor, putting the Company at risk for support for a business critical application.
Avoided Costs	field productivity: 3000 users at 10 minutes per day, improved software deployment - 3x deployments per year at a 30 minute reduction , – 4000 users - ELECTRIC - ELECT LINE CORRECTIVE MAINTENANCE - $13,500 O&M/$31,500 CAPITAL
Avoided Costs	field productivity: 3000 users at 10 minutes per day, improved software deployment - 3x deployments per year at a 30 minute reduction , – 4000 users - ELECTRIC - ELECTRIC METER - $40,500 O&M/$94,500 CAPITAL
Avoided Costs	field productivity: 3000 users at 10 minutes per day, improved software deployment - 3x deployments per year at a 30 minute reduction, – 4000 users - GAS - GAS DIST - $9,000 O&M/$36,000 CAPITAL
Avoided Costs	field productivity: 3000 users at 10 minutes per day, improved software deployment - 3x deployments per year at a 30 minute reduction, – 4000 users - GAS - GAS SERVICE/METER - $67,500 O&M/$67,500 CAPITAL
Intangibles	Live traffic display on Dispatch Application, Improved readability/usability of Dispatch Application, FieldWorker app enhancements to close gaps with Mobile Application and Enhanced Gantt Chart

SiteCore Primary Upgrade 2025

Report Pulled: 11/1/2024 **Item ID: 12727**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , SiteCore Upgrade 2025, SiteCore Primary Upgrade 2025

Description The project will refresh all components of the website hosting, delivery, search, and analytics applications to add new features and improve search capabilities. Sitecore is the content management application for the consumersenergy.com website, a channel many customers use for accessing account information and bill payment.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement Sitecore is currently operating on version 10.3, which is due to end mainstream support at the end of 2025. If this occurs, there will be an increase in support and maintenance fees of 10% above the annual subscription spend in order to purchase extended support, security updates and fixes will only be made available if the extended support is purchased, and product support for errors or required hotfixes that may impact platform stability will not be available even if extended support is purchased.

Objectives The project will add value for the Company by: (1) avoiding costs for extended maintenance agreements required at the end of mainstream support; (2) ensuring that the website retains the most up-to-date security posture; and (3) supporting the Company's CXI goals by improving reliability and performance.

Scope The project scope includes: (1) upgrading the Sitecore content management software to include content hosting and delivery allowing the use of new features and functionality; (2) migrating the Sitecore platform to the most up-to-date hardware and software by refreshing the application and database servers to a newer version of Windows Server and SQL Server.

Alternatives Alternatives considered include: (1) Delay the upgrade. This alternative was not chosen due to the current version falling outside of the mainstream support window, requiring an additional 10% in maintenance fees. Along with rapidly changing feature sets that are continually being developed by the vendor, the Company would be in a worse position to handle constantly changing cyber threats; (2) Migrate to a cloud solution. This alternative was not chosen due to the cost/benefit analysis of re-architecting our current Sitecore implementation to facilitate cloud migration is not viable at this time; and (3) Upgrade Sitecore on a two-year cycle. This alternative was chosen as it provides up-to-date functionality, stability, and mitigates cyber security risks while minimizing cost and impact.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
1/15/2025	3/22/2025	5/24/2025	9/30/2025
	In-Service/Go-Live	**Closeout**	
	10/1/2025	10/16/2025	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$0.116	-	-	-	-	-	-	-	$0.116
O&M	$0.245	-	-	-	-	-	-	-	$0.245
Total Cost of Ownership	$0.361	-	-	-	-	-	-	-	**$0.361**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$0.305	-	-	-	-	-	-	-	**$0.305**
Outside Services	-	-	-	-	-	-	-	-	-
Business Expense/Overheads	$0.056	-	-	-	-	-	-	-	**$0.056**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.361	-	-	-	-	-	-	-	**$0.361**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.245	-	-	-	-	-	-	-	**$0.245**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.245	-	-	-	-	-	-	-	**$0.245**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.116	-	-	-	-	-	-	-	**$0.116**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.116	-	-	-	-	-	-	-	**$0.116**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Avoid the cost of purchasing extended support from the vendor which comes at a 10% increase from normal licensing costs.
Risk Mitigation	If this project is not completed the company and the customers are at greater risk of encountering more reliability issues and cyber threats which could compromise the website. Keeping the Sitecore platform up to date will improve overall performance and reduce likelihood of operational issues. Additionally, the risk of cyber threats is reduced as patches and fixes are released on routine schedules.
Risk Mitigation	If website is either unavailable or not performing sufficiently, it will lead to a negative impact to Consumers Energy reputations with customers and lower JD Power scores. The website is a core contact point for the Company to interact with their customers. When Sitecore is not functioning completely the website will be impacted; potentially preventing customers from viewing their bill, make a payment, report an outage, and other functions.

SiteCore Secondary Upgrade 2023

Report Pulled: 11/1/2024 **Item ID: 12442**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias 2017 BizTalk Upgrade, SiteCore Upgrade 2024, SiteCore Upgrade 2023, SiteCore Secondary Upgrade 2023-2024, SiteCore Secondary Upgrade 2023

Description The project will ensure that all components of the website hosting, delivery, search, and analytics remain on the latest version, thereby retaining low-cost, unlimited vendor support. Sitecore is the content management application for the ConsumersEnergy.com website, a channel that many customers use for accessing account information and bill payment.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CUSTOMER EXP & OPS

WORK OBJECTIVES

Problem Statement Sitecore is currently operating on version 10.0, which is due to end mainstream support at the end of 2023. If this occurs, there will be an increase in support and maintenance fees of 10% above the annual subscription spend. Additionally, the Sitecore Experience Platform, a feature used for customer data analytics and marketing, has deprecated support for MongoDB and will require a move to SQL to maintain functionality.

Objectives The project will add value for the Company by: (1) avoiding costs for extended maintenance agreements required at the end of mainstream support; (2) ensuring that the website retains the most up-to-date security posture; (3) supporting the Company's CXI goals by improving reliability and performance; and (4) updating the customer analytics platform to SQL from MongoDB, ensuring the latest supported technology is used.

Scope The project scope includes: (1) upgrading the Sitecore content management software to the latest available version; and (2) migrating the Sitecore customer analytics module to the latest supported SQL platform.

Alternatives Alternatives considered include: (1) Delay the upgrade. This alternative was not chosen due to the current version falling outside of the mainstream support window, requiring an additional 10% in maintenance fees. Along with rapidly changing feature sets that are continually being developed by the vendor, the Company would be in a worse position to handle constantly changing cyber threats; (2) Undergo a full website redesign. This solution was not chosen as the cost/benefit analysis revealed this option is not viable at the time of filing; and (3) Upgrade Sitecore on a two-year cycle. This alternative was chosen as it provides up-to-date functionality, stability, and mitigates cyber security risks while minimizing cost and impact.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/3/2023	2/14/2023	3/14/2023	8/24/2023
	In-Service/Go-Live	**Closeout**	
	8/24/2023	9/15/2023	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.081	-	-	-	-	-	-	-	$0.081
Total Cost of Ownership	$0.081	-	-	-	-	-	-	-	**$0.081**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.053	-	-	-	-	-	-	-	**$0.053**
Outside Services	$0.023	-	-	-	-	-	-	-	**$0.023**
Business Expense/Overheads	$0.005	-	-	-	-	-	-	-	**$0.005**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.000	-	-	-	-	-	-	-	**$0.000**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.081	-	-	-	-	-	-	-	**$0.081**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.081	-	-	-	-	-	-	-	**$0.081**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.081	-	-	-	-	-	-	-	**$0.081**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Customer Management - As a result of this project, we will better be able to continue to manage customer experience by ensuring the website stays on a vendor supported version of the software.
Risk Mitigation	If this project is not completed the company and the customers are at greater risk of encountering more reliability issues and cyber threats which could compromise the website. Keeping the Sitecore platform up to date will improve overall performance and reduce likelihood of operational issues. Additionally, the risk of cyber threats is reduced as patches and fixes are released on routine schedules.
Risk Mitigation	If website is either unavailable or not performing sufficiently, it will lead to a negative impact to Consumers Energy reputations with customers and lower JD Power scores. The website is a core contact point for the Company to interact with their customers. When Sitecore is not functioning completely the website will be impacted; potentially preventing customers from viewing their bill, make a payment, report an outage, and other functions.

Software Asset - Service Management Upgrade

Report Pulled: 11/1/2024 **Item ID: 13928**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Software Asset - Service Management Upgrade

Description This project will optimize the software asset management process by systematically monitor, assess and oversee software licenses and compliance using Software Asset Management Professional.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement The on-premises software asset management technology currently used in the Company lacks compatibility to automate license reclamation, cost optimization, and license forecasting. These software asset management constraints lead to the inability to optimize software license purchasing and effective license demand management.

Objectives This project will create value by ensuring the Company's technology requirements are met through a comprehensive and cost-effective software asset management processes and workflow. Specifically, by replacing the on-premise application, the project will: (1) streamline the software request workflow including license reclamation and software deployment; (2) help ensure compliance with software license agreements; (3) identify opportunities of license optimization leading to cost optimization; (4) mitigate risk related to software asset management; (5) optimize license forecasting and (6) increase asset visibility.

Scope The project scope includes: (1) the implementation of software asset management tool; (2) the establishment of process and process roles needed to support the assets; and (3) retirement of the on-premise software asset management tool.

Alternatives Alternatives considered included: (1) Choose an alternate Cloud based asset management system. This alternative was not chosen as it would require introducing and integrating an additional vendor product into the technical landscape. (2) Develop a custom solution. This alternative was not chosen since the cost to build and maintain similar capabilities and to integrate the custom solution would not be feasible or cost effective. (3) Do nothing. This alternative was not selected as the current Software Asset Management tool that lacks integration and automation and will not address optimizing and effective management of licenses and purchases. (4) Develop and implement an on-premises Software Asset Management solution. This alternative ultimately chosen has strengths in software asset management and its integration capabilities with other platform modules from the same vendor. It offers a unified platform that can helps license compliance, optimization and automation.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
6/1/2023	9/1/2023	9/30/2023	10/1/2023
	In-Service/Go-Live	**Closeout**	
	2/29/2024	3/15/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$1.050	$0.070	-	-	-	-	-	-	$1.120
O&M	$0.180	$0.080	$0.005	$0.005	$0.005	$0.005	-	-	$0.280
Total Cost of Ownership	$1.230	$0.150	$0.005	$0.005	$0.005	$0.005	-	-	**$1.401**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.074	$0.053	-	-	-	-	-	-	**$0.128**
Outside Services	$0.331	$0.084	-	-	-	-	-	-	**$0.415**
Business Expense/Overheads	$0.029	$0.013	-	-	-	-	-	-	**$0.042**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$0.796	-	-	-	-	-	-	-	**$0.796**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.230	$0.150	-	-	-	-	-	-	**$1.381**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	$(0.180)	$(0.064)	-	-	-	-	-	**$(0.244)**
	Initial	$0.180	$0.080	$0.005	$0.005	$0.005	$0.005	-	-	**$0.280**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.180	$(0.100)	$(0.059)	$0.005	$0.005	$0.005	-	-	**$0.036**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.050	$0.070	-	-	-	-	-	-	**$1.120**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.050	$0.070	-	-	-	-	-	-	**$1.120**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -0.803

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Avoided cost by having automation built to reclaim licenses when a resource leaves the Company. SAM Pro will serve as the new Software Asset Management system of record, resulting in an annual cost savings of $66,000 and providing a single source to manage and request software and hardware. The cost savings here is from the 0.5 FTE HCL resource ($43,500) and 0.25 FTE CE resource ($22,500) that are not needed to manually maintain this process.
Technology Capability	By replacing the on-premise infrastructure with a Cloud Based System aligns with the Company goal of moving to the Cloud for better scalability and flexibility. This capability will help mitigate the labor of maintaining the current on-premise infrastructure with patching.
Technology Capability	SAM Pro provides the capability for better Automation on Software requests. With SNOW when a user requests for new Software, it took some time to check for the license availability and fulfill the request, but with SAM Pro the check happens real time and the latest version is procured. Governance improvements were made by adding extra checks in the workflow for EA (enterprise Architecture) and Cyber Security to do a high level review of the Software being requested to address any concerns early on.
Technology Capability	With the implementation of SAM Pro, there is no longer the need to sync up the software versions on 2 different systems (ServiceNow and SNOW) along with keeping the Product Owners and Technical Owners in sync for the software. SAM Pro also ensures that the SCCM ID has the latest version of the software to be pushed over to the user PC's when requested.

Software Platform Refresh

Report Pulled: 11/1/2024 **Item ID: 6843**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias Software Platform Refresh

Description The Software Platform Refresh project will upgrade server operating systems, hypervisors, databases and infrastructure platforms to retain low-cost vendor support.

Portfolio IT Services > Infrastructure > Data Center - Enterprise Computing > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement For systems that go beyond their normal manufacturer support ending, there will be increased support and maintenance fees of 20% to 100% above current support and maintenance depending on vendor. Completing this project allows the organization to (1) avoid high support costs; (2) provide for system security; and (3) stay current to promote seamless interoperability among servers, applications, and databases. Aging platforms are more susceptible to security vulnerabilities and performance issues that ultimately could affect the business and customers.

Objectives The project will add value for the Company by: (1) avoiding costs for special maintenance agreements required at the end of normal manufacturer support; (2) ensuring reliability and compliance with Information Security requirements; (3) improving data center environment stability; and (4) avoiding the need for high risk upgrades that cross multiple versions.

Scope The project scope includes: (1) upgrading operating systems and databases on servers that are near end of support with a given vendor; and (2) maintaining hypervisors and infrastructure platforms at the current version for stability and performance.

Alternatives A funding options matrix was completed to review the potential alternatives. The alternatives identified were: (1) Complete the full scope of the solution for $1 million in order to eliminate the need for ongoing extended support; (2) Reduce the scale of the solution, which requires $1.6 million in ongoing extended support; (3) Reduce the scale of the solution even further, which requires $2.4 million in ongoing extended support; (4) Do not complete a software platform refresh, which requires $3.3 million in ongoing extended support. Alternative 1 was selected as the most cost effective solution to ensure ongoing system stability; seamless integration; and mitigation of cyber-security risks without the significant cost of extended support necessary for end of life software systems.

DATES (phase end)

Initiation **Project Plan & Scope Definition** **Final Engineering, Planning & Design** **Execution**

In-Service/Go-Live **Closeout**

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	-	-	-	-	-	-	-	-
O&M	$0.138	$0.083	$0.113	$0.113	$0.113	$0.113	$0.113	-	$0.788
Total Cost of Ownership	$0.138	$0.083	$0.113	$0.113	$0.113	$0.113	$0.113	-	**$0.788**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.089	$0.019	$0.106	$0.106	$0.106	$0.106	$0.106	-	**$0.638**
Outside Services	$0.042	$0.005	-	-	-	-	-	-	**$0.047**
Business Expense/Overheads	$0.008	$0.001	$0.007	$0.007	$0.007	$0.007	$0.007	-	**$0.046**
Employee Benefits	-	-	-	-	-	-	-	-	**-**
Materials	-	-	-	-	-	-	-	-	**-**
Licenses, Permits & Fees	-	$0.057	-	-	-	-	-	-	**$0.057**
Other	-	-	-	-	-	-	-	-	**-**
Total Project Cost (Annual)	$0.138	$0.083	$0.113	$0.113	$0.113	$0.113	$0.113	-	**$0.788**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.138	$0.083	$0.113	$0.113	$0.113	$0.113	$0.113	-	**$0.788**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.138	$0.083	$0.113	$0.113	$0.113	$0.113	$0.113	-	**$0.788**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	High	There is a high risk of technology obsolescence that would result in a high impact to business and customer service operations. To mitigate this risk Consumers Energy can choose to pay significantly more for extended maintenance or complete the project with increased functionality at a lower cost.

OTHER VALUE

Type	Description
Technology Capability	Administrative & General (A&G) Support
Avoided Costs	Consumers Energy has 1,112 instances of operating systems, databases, and hypervisors that will require special maintenance contracts by January of 2020. Microsoft has identified additional maintenance costs of $705 per Central Processing Unit (CPU) Core running Windows 2008 starting in January of 2020. Consumers Energy has 4,718 CPU Cores running in the Windows 2008 environment for a total of $3,326,190 in additional maintenance charges.
Risk Mitigation	This project addresses the problem of new security vulnerabilities that would not be patched under extended maintenance.
Risk Mitigation	Through this project, Consumers Energy will be able to proactively patch systems to avoid bugs and stay current to promote seamless interoperability among servers.

SolarWinds Performance Monitoring Expansion Upgrade

Report Pulled: 11/1/2024 **Item ID: 13495**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , SolarWinds, SolarWinds Performance Monitoring Expansion Upgrade

Description This project will develop an IT observability and monitoring solution that provides an aggregate view of IT system availability and performance.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-INFRASTRUCTURE PLATFORMS &

WORK OBJECTIVES

Problem Statement

The current IT enterprise monitoring approach doesn't provide a comprehensive view of application and infrastructure health resulting in unplanned service interruptions, extended service interruptions, and system performance degradation. In addition, unplanned service interruptions have a negative impact on business partners ability to provide reliable services to utility customers.

Objectives

This project will allow IT to reduce the number of monitoring tools and consolidate end-to-end view of IT performance alerts to a single view. These actions will prevent major service interruptions, reduce major incident Mean Time to Restore, improve system stability, and ultimately avoid O&M labor cost.

Scope

This project scope includes: (1) performing a proof of value assessment for the following SolarWinds modules, Hybrid Cloud Observability ("HCO")/ Database Performance Analytics ("DPA")/ AppOptics/Pingdom); (2) transition applications monitored by AppDynamics to SolarWinds; (3) deploy configure agent base infrastructure monitors for applications and infrastructure (4) retire AppDynamics; (5) transition critical applications not monitored by AppDynamics to SolarWinds; (6) create performance monitoring dashboards for critical systems (7) define monitoring templates for rapid deployment of new monitoring services; and (8) training co-workers on use and management of SolarWinds.

Alternatives

The following alternatives were considered: (1) Renew current licenses for both SolarWinds and AppDynamics without achieving any savings or operational efficiencies. (2) Evaluate other vendors to replace AppDynamics at a reduced cost for service. Initial deployment and annual cost would significantly increase regardless of service selected. In addition, the other vendors considered did not have the capabilities to monitor both application and infrastructure which did not allow for a consolidated approach to be adopted and/or reduction in licensing and ongoing maintenance cost. As a result, this alternative was not selected. (3) In conclusion, SolarWinds was determined to be the most cost-effective approach because of the expanded capabilities offered through the following modules, HCO/ DPA/AppOptics/ Pingdom that meets the needs of IT to proactively monitor systems and retire tools with similar capabilities to reduce ongoing maintenance cost. Therefore, the alternative selected is to move forward with deploying the expanded services offered by SolarWinds.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
5/12/2023	5/19/2023	6/30/2023	9/29/2023
	In-Service/Go-Live	**Closeout**	
	10/27/2023	11/30/2023	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$1.763	$0.004	-	-	-	-	-	-	$1.767
O&M	$0.332	$0.004	-	-	-	-	-	-	$0.336
Total Cost of Ownership	$2.095	$0.008	-	-	-	-	-	-	**$2.103**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.112	$0.005	-	-	-	-	-	-	**$0.118**
Outside Services	$0.140	$0.001	-	-	-	-	-	-	**$0.141**
Business Expense/Overheads	$0.033	$0.001	-	-	-	-	-	-	**$0.034**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$1.810	$0.001	-	-	-	-	-	-	**$1.811**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$2.095	$0.008	-	-	-	-	-	-	**$2.103**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	$(0.012)	$(0.064)	$(0.062)	$(0.015)	-	-	-	-	**$(0.152)**
	Initial	$0.332	$0.004	-	-	-	-	-	-	**$0.336**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.321	$(0.060)	$(0.062)	$(0.015)	-	-	-	-	**$0.184**
Cap+COR	Reduction	$(0.058)	$(0.320)	$(0.311)	$(0.078)	-	-	-	-	**$(0.767)**
	Initial	$1.763	$0.004	-	-	-	-	-	-	**$1.767**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.704	$(0.316)	$(0.311)	$(0.078)	-	-	-	-	**$1.000**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.492

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Risk Mitigation	Proceeding with a standard renewal of SolarWinds and the inability to retire App Dynamics in its current state will decrease the level of end-to-end proactive monitoring required resulting in increasing services interruptions and operational costs.

Spatial Asset Management

EXECUTIVE SUMMARY

Report Pulled: 11/1/2024 **Item ID: 13940**

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Spatial Asset Management

Description This initiative will implement SAP's Spatial Asset Management module. It will allow users to view assets, notifications, and orders geospatially using a map. The module will allow the Company to create and maintain asset maintenance plans for each segment of our gas and electric distribution networks (linear assets). The Company will create linear assets as technical objects (such as functional locations and equipment) and store linear data. The Company will enable creation of maintenance plans for these technical objects which result in notifications, maintenance orders, and measurement documents. We will enable monitoring the condition of our linear assets, identify where there is damage or a defect (using the start point and end point and offset), and manage all types of maintenance tasks (planned, unplanned, and preventative).

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement Currently, the Company lacks spatial visualization and spatial awareness of work and assets impacting requirements for first time quality and impacting the ability to plan, bundle and execute nearby work. The lack of a linear asset management capability affects the full work management value stream resulting in overproduction of asset maintenance activity such as assessments, surveys, and inspections.

Objectives This project creates value for the Company by (1) providing capability in SAP to view assets, notifications, and work orders on a map; (2) providing location awareness in SAP for assets and work; (3) establishing linear asset management capability in SAP for gas and electric delivery networks; and (4) enabling end-to-end map-based workflows.

Scope The scope of this project encompasses implementation in SAP of the Spatial Asset Management module.

Alternatives Alternatives considered include: (1) Implement a cloud-based individualized asset integration between GIS and SAP. This alternative was not selected as it proves ineffective in addressing needs of the end-to-end work management value stream while increasing the technical footprint of customization. There are also performance concerns with cloud to on-prem integrations; (2) Implement work group centric approaches to viewing work on a map. This alternative was not selected as it does not support standard operation through the entire work management value stream; (3) Do nothing. This alternative was not selected as this would result in increasing costs and inefficiencies in gas and electric work management; and (4) The alternative to implement the Spatial Asset Management module in SAP was chosen as it expands use of a core technology investment, supports current investment in our work management value stream, and is compatible with our GIS technology.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
12/4/2023	4/30/2024	12/31/2024	10/31/2025
	In-Service/Go-Live	**Closeout**	
	11/1/2025	11/30/2025	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$1.532	$0.912	$0.714	-	-	-	-	-	$3.158
O&M	-	$0.099	$0.279	$0.172	$0.172	$0.172	$0.172	-	$1.067
Total Cost of Ownership	$1.532	$1.011	$0.993	$0.172	$0.172	$0.172	$0.172	-	**$4.225**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	-	$0.689	$0.240	-	-	-	-	-	**$0.929**
Outside Services	$0.160	$0.029	$0.420	-	-	-	-	-	**$0.609**
Business Expense/Overheads	$0.100	$0.061	$0.161	-	-	-	-	-	**$0.322**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	$1.272	$0.233	-	-	-	-	-	-	**$1.505**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$1.532	$1.011	$0.821	-	-	-	-	-	**$3.364**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.099	$0.279	$0.172	$0.172	$0.172	$0.172	-	**$1.067**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.099	$0.279	$0.172	$0.172	$0.172	$0.172	-	**$1.067**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$1.532	$0.912	$0.714	-	-	-	-	-	**$3.158**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$1.532	$0.912	$0.714	-	-	-	-	-	**$3.158**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Intangibles	SAM supports a single platform for engineers and designers that consolidates multiple data sources & third-party tools and provides templates to accelerate projects.
Intangibles	SAM supports workflow and collaboration thru smart notifications, annotations, and messaging embedded throughout the platform.

Standard Work Plan

Report Pulled: 11/1/2024 **Item ID: 13969**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Initiative

Alias , Standard Work Plan

Description The Gas and Electric Resource Planning process is solely reliant on spreadsheets and manual data collection from numerous, disparate sources. It is not only time-consuming but also prone to errors, leading to potential inefficiencies in resource allocation and a lack of detailed, insightful planning. The sole use of spreadsheets makes analyses and what-if scenario development cumbersome. The lack of workplan controls contributes to the completion of pull-ahead work resulting in unnecessary OT and contractor expense. Implementing a centralized planning platform that will interface with existing systems like SAP, DAPP, and EAM Dashboard would transform our planning organization, offering a clear view of planned work and ensuring that executed work is aligned with strategic objectives. In addition, a more integrated system that leverages automation and real-time data analytics would allow for the immediate, what-if scenario planning the business needs to support sound, data-driven decision-making. The tool, alongside necessary process and system enhancements will streamline the workflow and ultimately lead to schedule quality and ensure prudent overtime and contractor usage through reducing the amount of unplanned work breaking into the work management process. A shift to a digital solution that fully aligns resources, work units and feeds the schedule will represent a significant step forward in resource management, aligning with modern best practices.

Portfolio Electric Delivery Systems > * > * > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement The Gas and Electric Resource Planning process is solely reliant on spreadsheets and manual data collection from numerous, disparate sources. It is not only time-consuming but also prone to errors, leading to potential inefficiencies in resource allocation and a lack of detailed, insightful planning. The sole use of spreadsheets makes analyses and what-if scenario development cumbersome. The lack of workplan controls contributes to the completion of pull-ahead work resulting in unnecessary OT and contractor expense.

Objectives The project will add value by: (1) improving Work Planning Annual Forecast Process: This involves the enhancement of automated inputs, processing, and reporting with a shift towards a more asset-driven prioritization method and; (2) converting Monthly Work Plans into Weekly Schedules: Establish a process that seamlessly transforms monthly work plans into executable weekly schedules for easy handoff from planning to scheduling; (3) providing the ability to Run Forecasting and Planning Scenarios: Execute forecasting and planning scenarios and provide comparative analysis; (4) improve system visibility of Work Planned jobs increasing forecast accuracy of downstream processes ; and (5) creating multiple dashboards based on the audience of the data providing visibility across all levels of Operations Leadership as well as Supply Chain proactively informing of upcoming workload, potential gaps, opportunities for contingencies if levers are pulled, and clean executable work keeping our workforce fully engaged and productive. This results in improved Field Operations and Customer Satisfaction with delivery commitments and meeting reliability and compliance dates.

Scope The project scope includes the following: (1) developing a system for Work Planning Annual and Monthly forecast with automation; (2) creating the ability to translate the Monthly forecast into an executable Weekly Schedule; (3) creating technology for running Planning Scenarios with ability to compare scenarios for optimized field execution; (4) improving system visibility of Work Planned jobs increasing forecast accuracy of downstream processes (ie. materials); and (5) building Dashboards and reports to provide visibility and help management maintain process control.

Alternatives Alternatives considered: (1) Purchase commercially available system. This option was not selected as a single all compassing system does not link the Annual forecasting to execution. Products reviewed included Prometheus. (2) Microsoft Excel based solution, extending the Microsoft excel based solution was not selected as it did not provide the level of data integration for controlling large number of forecasted work items. (3) Development of a system that integrates with our SAP investment. This option was not selected as it does not align to expected value delivery timeline. (4) Purchase a SaaS solution to enable planning & forecasting with integration to our SAP work management system. The fourth alternative was selected because it aligns to the expected value delivery timeline and meets the functional requirements.

DATES (phase end)

Initiation	**Project Plan & Scope Definition**	**Final Engineering, Planning & Design**	**Execution**
6/4/2024	6/25/2024	9/13/2024	11/29/2024
	In-Service/Go-Live	**Closeout**	
	1/31/2025	2/28/2025	

FUNDING SUMMARY

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Cap+COR	-	$0.922	-	-	-	-	-	-	$0.922
O&M	-	$0.892	$0.753	$0.753	$0.753	$0.753	-	-	$3.905
Total Cost of Ownership	-	$1.815	$0.753	$0.753	$0.753	$0.753	-	-	**$4.827**

	2024	2025	2026	2027	2028	2029	2030	2031 +	Total
Labor	-	$0.510	-	-	-	-	-	-	**$0.510**
Outside Services	-	$0.578	$0.213	$0.213	$0.213	$0.213	-	-	**$1.430**
Business Expense/Overheads	-	$0.282	$0.015	$0.015	$0.015	$0.015	-	-	**$0.341**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	$0.445	$0.445	$0.445	$0.445	$0.445	-	-	**$2.226**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$1.815	$0.673	$0.673	$0.673	$0.673	-	-	**$4.507**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2024	2025	2026	2027	2028	2029	2030	2031 +	Total
O&M	Reduction	-	$(0.100)	-	-	-	-	-	-	**$(0.100)**
	Initial	-	$0.892	$0.753	$0.753	$0.753	$0.753	-	-	**$3.905**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.792	$0.753	$0.753	$0.753	$0.753	-	-	**$3.805**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.922	-	-	-	-	-	-	**$0.922**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.922	-	-	-	-	-	-	**$0.922**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.978

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Avoided Costs	Reduced capital cost @25% of annual average cost of orders providing $1,600,193 cost avoidance
Avoided Costs	Reduced capital cost @25% of annual average cost of orders providing $1,770,741 cost avoidance
Avoided Costs	Reduced O&M cost @25% of annual average cost of orders providing $37,582 cost avoidance
Avoided Costs	Reduced O&M cost @25% of annual average cost of orders providing $511,138 cost avoidance

Talent Management Enablement

Report Pulled: 11/1/2024 **Item ID: 11828**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias , Talent Management Enablement

Description The project will deliver technology solutions to enable best-in-class Talent Management programs and processes that are critical to achieve the Company's overarching Talent Strategy Plan. The Talent Strategy Plan is a key enabler of the company's Integrated Resource Plan (IRP), Electric Distribution Infrastructure Investment Plan (EDIIP), and Natural Gas Delivery Plan (NGDP). Effective Talent Management programs and processes are critical to develop the skills, capabilities, productivity, and experience necessary to successfully execute these plans that deliver clean, reliable, affordable energy through an exceptional customer experience.

Portfolio IT Services > Applications > Corporate Services > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-CORPORATE

WORK OBJECTIVES

Problem Statement Significant technology improvements are required to transform Human Resources (HR) to develop the skills and capabilities necessary to achieve the Company's strategic destination. Currently, many Talent Management processes are manually managed with little or no technology enablement. Specifically, the talent compensation processes are mostly manually done outside the system which introduces waste, and a potential for errors. In addition there is a limited visibility of competency gaps within the workforce. The Company cannot effectively place talent in accelerated development programs aligned to competency gaps, nor can it recognize and motivate employees for quickly increasing competency and performance. Furthermore, the Company operates in an increasingly competitive job market where candidates and employees expect best-in-class processes, technologies and experiences relative to their employment and career development. The lack of full technical enablement across Talent Management programs poses a risk to employee attraction, retention and limits the ability to develop the right skills at the right time to deliver on Company strategies.

Objectives This project will add value to the Company through technology that will enable: (1) fully functional integrated compensation module; (2) accelerated and targeted talent development of critical skills necessary to deliver on the Company's commitment to clean energy and exceptional customer experience; (3) transparency into talent and skill gaps in order to identify retention and service delivery risks within critical areas, as well as inform succession and hiring strategies; (4) improved knowledge transfer, business continuity, and customer service during a time when retirement eligibility is high and risk of knowledge loss has the potential to negatively impact customer service and satisfaction; and (5) increased efficiency and quality of talent management through simplified and automated processes that reduce costs associated with recruiting, onboarding, and developing employees. Talent Management Enablement will deliver the best-practice technology to enable and enhance (1) Fully functional integrated talent compensation management; (2) Simplified and automated talent management process for employee lifecycle management from on-boarding through Off-boarding; (3) Succession Planning and Business Continuity; (4) Career Development and Employee Retention.

Scope The scope will include: (1) implementation of each system/application; (2) integration with current systems, applications and processes as applicable; (3) retrofit current systems and applications to ensure a seamless end-to-end experience of HR processes; (4) delivery of mobile capabilities for in scope processes; (5) reporting and analytics dashboards and report insights for in scope processes.

Alternatives Three alternatives were considered for these Talent Management programs and processes: (1) Develop custom, internally built solutions that could meet most requirements. This alternative was not selected because a custom solution would result in higher overall costs, higher maintenance costs, fewer upgrades, and would not leverage industry best practices to ensure best-in-class delivery. (2) Select an on-premise software tool. This alternative was not selected because it requires internal maintenance, increases infrastructure costs, and would have less frequent upgrades which would hinder the Company's ability to ensure processes are evolving alongside industry trends and best practices. (3) Evaluate and select cloud/SaaS solution(s) which would have lower infrastructure costs, less internal maintenance than an on-premise solution, and would be built and evolved with upgrades based on industry best practices. Based on research, internal experience with successful best practice implementations, and vendor demonstrations, option three was selected.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
2/1/2023	3/1/2023	5/1/2023	7/1/2023
	In-Service/Go-Live	**Closeout**	
	8/30/2025	10/30/2025	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	$0.229	$0.441	$0.551	-	-	-	-	-	$1.222
O&M	$0.204	$0.165	$0.096	$0.100	$0.100	-	-	-	$0.665
Total Cost of Ownership	$0.433	$0.606	$0.647	$0.100	$0.100	-	-	-	**$1.886**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	$0.020	$0.390	$0.225	-	-	-	-	-	**$0.635**
Outside Services	$0.388	$0.209	$0.285	-	-	-	-	-	**$0.881**
Business Expense/Overheads	$0.026	$0.007	$0.137	-	-	-	-	-	**$0.170**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.433	$0.606	$0.647	-	-	-	-	-	**$1.686**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.204	$0.165	$0.096	$0.100	$0.100	-	-	-	**$0.665**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.204	$0.165	$0.096	$0.100	$0.100	-	-	-	**$0.665**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.229	$0.441	$0.551	-	-	-	-	-	**$1.222**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.229	$0.441	$0.551	-	-	-	-	-	**$1.222**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	Administrative & General Support
Intangibles	Avoid inability to meet and support quality and timely delivery of the Company's customer centric strategy
Technology Capability	Deliver mobile-enabled Talent Management processes that will facilitate leaders' ability to minimize administrative downtime by increasing accessibility to core talent management processes, forms, approvals, and tracking.
Intangibles	Delivery of best-in-class technically enabled talent programs will enhance the attraction and retention of top talent in an increasingly competitive and geographically expanding job market.
Technology Capability	Eliminate wasted hours associated with the manual management of the Succession Planning process
Risk Mitigation	Mitigate risk due to 19% of the current customer-facing workforce that has 25+ years tenure by enabling effective Talent Management processes to prepare for these retirements to ensure continuation of strong customer delivery by facilitating employee development, engagement, succession planning and performance management
Risk Mitigation	Mitigate the risk of losing high performing talent or not being able to recruit the strongest talent to deliver on company strategies which support customer service and value delivery.
Technology Capability	Reduce waste generated by manual consolidation of data for reporting purposes by delivering standard and custom Talent Management reporting.

Tibco API Exchange Gateway Replacement

Report Pulled: 11/1/2024 **Item ID: 11728**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Maintain - Interval **Work Type** Project

Alias , Tibco API Exchange Gateway Replacement

Description This project is looking to retire the API Exchange Gateway within the Tibco ESB and replace it with a new solution called Microsoft Self-Hosted Gateway. The API Exchange Gateway is used by the TIBCO ESB to integrate to external vendors, all new development will need to be done to integrate this solution.

Portfolio IT Services > Applications > Foundational Enterprise Applications > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-APPLICATION PLATFORMS & SER

WORK OBJECTIVES

Problem Statement The Tibco API Exchange Gateway is anticipated to be sunset by the vendor, as they have already dropped all development of enhancements for the platform.

Objectives This project creates value for the Company by: (1) Avoiding the risk of running a project no longer supported by the vendor (i.e. the Tibco Enterprise Service Bus API Exchange module), and (2) Enabling the Company the opportunity to move to a product that is more stable, secure, and usable.

Scope The project scope includes: (1) Conducting a RFP to procure a replacement product and work with architecture team to migrate the product. (2) Migrate all current work items to the new platform. (3) Conduct appropriate testing to ensure all Service Level Agreements are met.

Alternatives Alternatives considered include: (1) Evaluating the replacement of the current product with a new product that is not already in the Company environment. This alternative was not selected because it would not be cost effective. (2) Keeping the current application as-is. This alternative was not selected as the vendor for the current platform has stopped all development for this product. (3) Leveraging an existing solution already in the Company environment. This alternative was selected as it avoids multiple solutions with redundant capabilities and avoids costs for supporting and maintaining a second solution.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/15/2024	2/5/2024	3/5/2024	4/1/2024
	In-Service/Go-Live	**Closeout**	
	8/5/2024	12/13/2024	

FUNDING SUMMARY

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Cap+COR	-	$0.900	-	-	-	-	-	-	$0.900
O&M	-	$0.123	-	-	-	-	-	-	$0.123
Total Cost of Ownership	-	$1.022	-	-	-	-	-	-	**$1.022**

	2023	2024	2025	2026	2027	2028	2029	2030 +	Total
Labor	-	$0.913	-	-	-	-	-	-	**$0.913**
Outside Services	-	$0.106	-	-	-	-	-	-	**$0.106**
Business Expense/Overheads	-	$0.003	-	-	-	-	-	-	**$0.003**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	-	-	-	-	-	-	-	-
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	-	$1.022	-	-	-	-	-	-	**$1.022**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2023	2024	2025	2026	2027	2028	2029	2030 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.123	-	-	-	-	-	-	**$0.123**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.123	-	-	-	-	-	-	**$0.123**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	$0.900	-	-	-	-	-	-	**$0.900**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	$0.900	-	-	-	-	-	-	**$0.900**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Technology Obsolescence	High	Medium	TIBCO has announced that the API Exchange Gateway will no longer be developed and supported, so we are at risk of being reliant on software that is obsolete.

OTHER VALUE

Type	Description

Tracking & Traceability

Report Pulled: 11/1/2024 **Item ID: 6863**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - One Time **Work Type** Project

Alias Tracking & Traceability

Description Tracking and Traceability is a project driven from proposed regulatory rules that will require utilities to map new and replacement installations with tracking and traceability data for plastic pipes, fittings, and fusions for the lifetime of the asset.

Portfolio IT Services > Applications > Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-GAS

WORK OBJECTIVES

Problem Statement

The Company does not currently have a Tracking and Traceability program that will meet PHMSA proposed requirements (PHMSA-2014-0098), also known as the Plastic Pipe Rule. Tracking and traceability refers to the collection of information that provides manufacturing, material type, and location information for pipe and components. PHMSA defines the terms "tracking" and "traceability" as follows: (1) Tracking is information that provides for the identification and location of pipe and components, the date installed, and the person who made the joints in the pipeline system; and (2) Traceability is within American Society for Testing and Materials (ASTM) F2897-11a and includes a unique identifier for the location of manufacture, production, lot information, size, material, pressure rating, temperature rating and, as appropriate, type, grade and model of pipe and components. PHMSA will be requiring each pipeline operator to maintain tracking and traceability information for the life of installed pipeline segments. The lack of adequate traceability for plastic pipe and tracking of pipe location prevents gas pipeline operators from having enough information to identify systemic issues related to incidents involving plastic pipe. The lack of this information makes it difficult for operators and regulators to determine whether plastic pipe or component failures are related to a certain type or vintage of material, specific product defect or design, heat/lot of the product, or whether it was produced by a certain manufacturer at a certain time. The lack of information can result in excessive pipe excavations due to an inability to locate the affected sections of pipe or fittings when responding to plastic pipe or component manufacturer recalls.

Objectives

This project will develop a sustainable Tracking and Traceability program that will meet PHMSA requirements (PHMSA-2014-0098) which address the proposed tracking and traceability requirements. The project adds value by capturing traceability data via barcode readers and location tracking information via Global Positioning System (GPS) equipment to improve the quality of data and assist the Company in determining future scopes of work in the event of any component manufacture recalls.

Scope

The scope of work will include: (1) changes in SAP Supply Chain processes to capture the required barcode information for all plastic components used in gas distribution and service lines; (2) changes in SAP Work Management processes to account for capturing barcode information as part of material components added to work orders, capturing fusion information from work order completion and capturing GPS coordinates from work order completion; (3) changes in GIS to capture GPS coordinates of plastic components and GPS coordinates of component fusions; (4) building of a repository for tracking and traceability reporting and analysis; (5) purchasing barcode reading equipment for storerooms and gas distribution trucks; and (6) purchasing of GPS locating equipment to capture coordinates.

Alternatives

Alternatives considered: (1) The do nothing alternative, which was not selected because it would expose the company to significant legal and financial risk resulting from non-compliance. (2) Internally develope digital technology supporting the tracking & traceability standards included in the PHMSA-2014-0098 plastic pipe rule. The second alternative is being pursued by the Company.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/1/2025	4/1/2025	9/1/2025	9/30/2026
	In-Service/Go-Live	**Closeout**	
	4/30/2027	6/30/2027	

FUNDING SUMMARY

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Cap+COR	$3.326	$7.278	$4.261	-	-	-	-	-	$14.865
O&M	$0.755	$0.753	$0.320	$0.320	$0.320	$0.320	$0.075	-	$2.864
Total Cost of Ownership	$4.082	$8.031	$4.581	$0.320	$0.320	$0.320	$0.075	-	**$17.729**

	2025	2026	2027	2028	2029	2030	2031	2032 +	Total
Labor	$2.125	$2.125	-	-	-	-	-	-	**$4.250**
Outside Services	$0.406	$0.404	-	-	-	-	-	-	**$0.810**
Business Expense/Overheads	$1.015	$1.245	$0.249	-	-	-	-	-	**$2.508**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	$0.291	$4.012	$4.012	-	-	-	-	-	**$8.315**
Licenses, Permits & Fees	$0.245	$0.245	$0.245	$0.245	$0.245	$0.245	-	-	**$1.470**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$4.082	$8.031	$4.506	$0.245	$0.245	$0.245	-	-	**$17.354**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2025	2026	2027	2028	2029	2030	2031	2032 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.755	$0.753	$0.320	$0.320	$0.320	$0.320	$0.075	-	**$2.864**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.755	$0.753	$0.320	$0.320	$0.320	$0.320	$0.075	-	**$2.864**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$3.326	$7.278	$4.261	-	-	-	-	-	**$14.865**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$3.326	$7.278	$4.261	-	-	-	-	-	**$14.865**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall) -1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description
Gas Distribution System	Medium	Medium	DRAM Risk Model – Distribution risk model accuracy. Improve quality of gas pipe attribution. Improve location of leak location.
Compliance - Gas Code	Low	Medium	MPSC Non-compliance - Excavation Tickets; Construction practices – failure to install components (through capturing the barcode we have check/balance)

OTHER VALUE

Type	Description
Risk Mitigation	Accurate positional data (valves in particular) leads to better emergency response.
Technology Capability	Automation for asset and location capture to GIS.
Avoided Costs	Data collection efforts through bar code scanning automation vs manual entry of bar code numbers. Average annual savings based upon 10 mins saved at $200 / hour across 10,000 work orders = approximately $330,000
Intangibles	Data collection for asset information being much more accurate
Risk Mitigation	Ease isolation/plan of attack for Risk Mitigation (DIMP System Integrity)
Risk Mitigation	Expired material identification (Pipe or fittings exposed to UV) (link to supply chain business case)
Intangibles	Fusion collection tied to each joint - Equipment used; Operator OQ
Risk Mitigation	Improve coordination with 3rd party entities.
Intangibles	Leak Data accuracy and analysis
Risk Mitigation	Location of factory recalled components
Intangibles	Public Reputation: What we might get from the public being a world-class company. Less damage to property with subsequent maintenance.
Technology Capability	Quality control capabilities in real-time

TSA Critical Facility Structure

Report Pulled: 11/1/2024 **Item ID: 12443**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Comply - One Time **Work Type** Project

Alias , TSA Critical Facility Structure

Description This project will implement enhanced security measures outlined by the Transportation Security Administration (TSA) for critical facility assets in order to bring the locations up to enhanced status and avoid non-compliances. This project will increase the security and reliability of gas delivery to our customers while also meeting federal requirements.

Portfolio Corporate Services > Security Services > Security > * > * > *

Org CX&T **Bus Unit** SECURITY **Dept** CX&T-SECURITY-COMPLIANCE

WORK OBJECTIVES

Problem Statement Pipeline facilities that are deemed critical are required to apply enhanced security measures. Today, the Company currently has designated 4 locations as critical. However, based on the April 2021 update to the TSA Pipeline Security Guidelines, Section 5 (Critical Facility Criteria), a significant number of our gas infrastructure that were not previously subject to evaluation will now fall into scope. As the Company continues to analyze the remainder of our gas assets, there is the potential for an additional 1,000 pipeline facilities (pipeline interconnections, metering and/or regulating stations, pump stations, compressor stations, operational control facilities, main line valve, tank farms and terminals, etc.) may be deemed critical. The Company will be taking a phased implementation approach and will begin the process by implementing the enhanced security measures at the reminder of our compressor stations. Failure to update our sites will put the Company out of compliance with the updated guidelines.

Objectives This project provides value to the Company by: (1) Implementing enhanced security measures outlined by the TSA for four critical assets; and (2) Increasing the security and reliability of gas delivery to our customers while meeting federal requirements.

Scope This project will implement the following enhanced security measures: (1) access controls; (2) access readers; (3) cameras; (4) video and audio programming; (5) fencing and barriers; (6) gates; (7) locks and key control; (8) fence intrusion; (9) subcontractor work of trenching poles, etc.; (10) facility lighting; (11) background investigations for personnel working at the site; (12) security equipment maintenance and testing; (13) security vulnerability assessments; (14) security communication plans; (15) personnel training; and (16) security drills and exercises for the following locations.

Alternatives Alternatives considered were: (1) To not implement the enhanced security measures outlined by the Transportation Security Administration (TSA) for critical facility assets. This option was not chosen due to the risk of not complying with the TSA enhanced security measures. (2) To implement the enhanced security measures outlined by the Transportation Security Administration (TSA) for critical facility assets. This alternative was chosen to avoid the risk of not complying with the TSA enhance security measures, such as increased vulnerability of attacks, financial penalties, and operational disruptions.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/1/2023	3/31/2023	6/30/2023	10/31/2025
	In-Service/Go-Live	**Closeout**	
	11/1/2025	11/30/2025	

FUNDING SUMMARY

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Cap+COR	$0.074	$1.000	$1.866	$3.797	$2.352	-	-	-	$9.088
O&M	$0.285	$0.124	$0.060	$0.030	$0.086	-	-	-	$0.585
Total Cost of Ownership	$0.358	$1.124	$1.927	$3.827	$2.438	-	-	-	**$9.673**

	2021	2022	2023	2024	2025	2026	2027	2028 +	Total
Labor	$0.131	$0.100	$0.243	$0.084	$0.480	-	-	-	**$1.039**
Outside Services	$0.227	$0.650	$0.639	$2.846	$0.800	-	-	-	**$5.162**
Business Expense/Overheads	$0.000	$0.024	$0.056	$0.028	$0.158	-	-	-	**$0.267**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.350	$0.987	$0.868	$1.000	-	-	-	**$3.206**
Licenses, Permits & Fees	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.358	$1.124	$1.927	$3.827	$2.438	-	-	-	**$9.673**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2021	2022	2023	2024	2025	2026	2027	2028 +	Total
O&M	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.285	$0.124	$0.060	$0.030	$0.086	-	-	-	**$0.585**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.285	$0.124	$0.060	$0.030	$0.086	-	-	-	**$0.585**
Cap+COR	Reduction	-	-	-	-	-	-	-	-	-
	Initial	$0.074	$1.000	$1.866	$3.797	$2.352	-	-	-	**$9.088**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.074	$1.000	$1.866	$3.797	$2.352	-	-	-	**$9.088**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-1.000

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description

Work Management Scheduling Analytics and Reporting

Report Pulled: 11/1/2024 **Item ID: 6811**

EXECUTIVE SUMMARY

BASIC INFORMATION

Work Category Strategic/Grow **Work Type** Project

Alias DCO Scheduling Tool Project, DOET Scheduling Tool Project,Work Management Scheduling, Analytics, and Reporting, Work Management Scheduling Analytics and Reporting

Description The project will implement a solution to optimize the key components of the Distribution Planning and Scheduling functions including forecasting, work order intake, resource identification, work schedule creation, work execution preparation and associated work order analytics.

Portfolio IT Services > Applications > Common Delivery Systems > * > * > *

Org CX&T **Bus Unit** INFORMATION TECHNOLOGY **Dept** CX&T-IT-WORK MANAGEMENT

WORK OBJECTIVES

Problem Statement The Distribution Planning, Scheduling and Administrative Support & Financial Services (Work Plan Strategy) teams are utilizing manually intensive work methods, systems and forecasting models. These inefficiencies impact the creation of work plans, lack predictive capacity planning, and reduce productivity of operational partners.

Objectives The project will add value by providing: (1) streamlined processes tied to workload review and preparatory analysis, leading to increased focus on workload priority, execution of work and a reduction of human struggle; (2)increased accuracy in crew work schedules, leading to improved customer satisfaction and on-time delivery of customer requested work, system integrity work, and gas compliance requirements; (3) reduced manual scheduling steps, reporting and analysis of data associated with work management processes and systems; thereby minimizing the risk of human error hours spent developing and updating crew route sheets; and (4) improved forecasting accuracy, that results in greater transparency into the weekly schedule and associated work plan.

Scope The project scope includes: (1) implement a solution to facilitate the review of work orders from various engineering organizations, allowing for streamlined check-in of work orders; (2) implement a scheduling tool that utilizes predictive modelling and advanced analytics and streamlines daily schedule modifications; (3) enhance integration with the Arcos application to bring in employee capacity and availability information; (4) integrate with SAP to retrieve work order data and manage record keeping requirements; (5) enhance integration with Field Service Suite (FSS) for quicker access to MISS DIG information and work order assignments; and (6) implement associated analytics and reporting.

Alternatives Three primary alternatives were considered for this project: (1) Automating manual data movement across excel and current systems through Robotic Process Automation. This option was not chosen because it will not meet base requirements and will not provide desired insights into whether the schedule supports operating priorities and metrics, financial scenarios, first time completion of work, and daily goals; (2) Integrating an off-the-shelf planning and scheduling system. This option is not preferred due to associated up-front and long-term costs; and (3) Implementing a hybrid of an off-the-shelf planning component with custom built scheduling functions. This is the preferred option to provide a more cost-effective and targeted fit for the organization.

DATES (phase end)

Initiation	Project Plan & Scope Definition	Final Engineering, Planning & Design	Execution
1/11/2022	4/16/2022	6/18/2022	1/28/2023
	In-Service/Go-Live	**Closeout**	
	10/9/2024	10/16/2024	

FUNDING SUMMARY

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Cap+COR	$0.825	$0.952	$0.506	-	-	-	-	-	$2.283
O&M	$0.071	$0.046	$0.059	$0.075	$0.075	$0.075	$0.075	-	$0.477
Total Cost of Ownership	$0.896	$0.998	$0.566	$0.075	$0.075	$0.075	$0.075	-	**$2.760**

	2022	2023	2024	2025	2026	2027	2028	2029 +	Total
Labor	$0.122	$0.195	$0.448	-	-	-	-	-	**$0.765**
Outside Services	$0.678	$0.630	$0.045	-	-	-	-	-	**$1.353**
Business Expense/Overheads	$0.088	$0.141	$0.013	-	-	-	-	-	**$0.241**
Employee Benefits	-	-	-	-	-	-	-	-	-
Materials	-	$0.000	-	-	-	-	-	-	**$0.000**
Licenses, Permits & Fees	$0.009	$0.032	$0.059	-	-	-	-	-	**$0.100**
Other	-	-	-	-	-	-	-	-	-
Total Project Cost	$0.896	$0.998	$0.566	-	-	-	-	-	**$2.460**

VALUE & IMPACTS SUMMARY

FINANCIAL IMPACTS

		2022	2023	2024	2025	2026	2027	2028	2029 +	Total
O&M	Reduction	-	$(0.045)	$(0.054)	$(0.054)	$(0.054)	$(0.054)	$(0.054)	-	**$(0.314)**
	Initial	$0.071	$0.046	$0.059	$0.075	$0.075	$0.075	$0.075	-	**$0.477**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.071	$0.001	$0.006	$0.021	$0.021	$0.021	$0.021	-	**$0.163**
Cap+COR	Reduction	-	$(0.159)	$(0.191)	$(0.191)	$(0.191)	$(0.191)	$(0.191)	-	**$(1.113)**
	Initial	$0.825	$0.952	$0.506	-	-	-	-	-	**$2.283**
	Incremental	-	-	-	-	-	-	-	-	-
	Net	$0.825	$0.793	$0.315	$(0.191)	$(0.191)	$(0.191)	$(0.191)	-	**$1.170**
Revenue	Reduction	-	-	-	-	-	-	-	-	-
	Initial	-	-	-	-	-	-	-	-	-
	Incremental	-	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-	-

B/C Ratio (Overall)	-0.567

Risk Tolerance

Corporate Risk	Impact	Likelihood	Description

OTHER VALUE

Type	Description
Technology Capability	5 - Work Management
Intangibles	As a result of improved forecasting accuracy, greater transparency into the weekly schedule and associated work plan would lead to improved on time completion of workplan elements relating to customer requested work and system improvement projects. It would also support problem solving in unit/hourly costs.
Intangibles	Employee engagement is improved by reducing human struggle, while being able to focus on priority and execution of work versus relying on workarounds and extra steps to meet daily scheduling needs.
Intangibles	Increased accuracy in crew work schedules, resulting in increased on-time completion of electric system integrity and gas compliance work. Based on the reduction of scheduling errors, a projected increase of 10% in the First Time Quality scheduling metric.
Intangibles	Increased accuracy of crew work schedules and First Time Quality are projected to lead to a 4% increase in Customer Satisfaction as measured by CXi
Avoided Costs	Initial savings based on implementation at one Company service center yielded $50,000 in savings from reduced truck rolls and reduced job delays through an enhanced quality control process . It is the intention of the Company to expand this statewide where further savings will be realized.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Programs
Projected Gas and Common Capital Expenditures
For the Projected Year 2025 and Test Year Ending October 31, 2026
For the Historical Year 2023 and Projected Year 2024

Case No.: U-21806
Exhibit No.: A-22 (SHB-7)
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Date: December 2024

ARP-Collaboration

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	Avg. Unit Cost	Total 2025 Units	Total 2026 Units	Total 2025 Dollars	Total 2026 Dollars	Total Test Year Dollars	Gas Allocation Dollars
1	Conference room refresh - Small	$15,000	2	1	$30,000	$15,000	$17,500	$5,500
2	Conference room refresh -Large	$50,000	1	1	$50,000	$50,000	$50,000	$15,715
3	Conference room refresh - Auditorium	$150,000	1	1	$150,000	$150,000	$150,000	$47,145
4	Digital Signage refresh - LCD Displays	$1,650	21	20	$34,650	$33,000	$33,275	$10,458
5	Digital Signage refresh Phase 4	$1,650	0	20	$0	$33,000	$27,500	$8,643
6	New Teams Rooms	$10,000	2	2	$20,000	$20,000	$20,000	$6,286
7	PolyCom Refresh	$5,500	20	0	$110,000	$0	$18,333	$5,762
8	PolyCom Refresh	$7,500	0	14	$0	$105,000	$87,500	$27,501
9	PolyComm Video Conferencing Replacements	$2,000	0	14	$0	$28,000	$23,333	$7,334
10	Replace existing VGA equipment with HDMI	$2,000	1	1	$2,000	$2,000	$2,000	$629
11	Surface Hub 85" Gen 1 replacement	$27,300	10	0	$273,000	$0	$45,500	$14,301
12	Surface Hub 85" Gen 1 replacement	$28,700	0	10	$0	$287,000	$239,167	$75,170
13	Surface Hubs Gen 1 replacement 50"	$12,500	2	0	$25,000	$0	$4,167	$1,310
14	Surface Hubs Gen 1 replacement 50"	$13,340	0	10	$0	$133,400	$111,167	$34,940
15	Surface Hub Refresh 50"	$12,500	4	0	$50,000	$0	$8,333	$2,619
16	Surface Hub Refresh 50"	$13,340	0	5	$0	$66,700	$55,583	$17,470
17	Antenas	$27,300	4	0	$109,200	$0	$18,200	$5,720
18	Surface Hub Refresh 85"	$28,140	0	5	$0	$140,700	$117,250	$36,852
19	UPS 2020	$980	18	9	$17,640	$8,820	$10,290	$3,234
20	Verint Servers/Software	$418,260	0	1	$0	$418,260	$348,550	$109,549
21	Software, labor, contractor and overhead and other costs				$314,345	$263,662	$272,109	$85,524
22	**Total Gas Allocation**				$1,185,835	$1,754,542	**$1,659,757**	**$521,662**

	Units	Avg. Unit Cost	Total 2023 Units	Total 2024 Units	Total 2023 Dollars	Total 2024 Dollars	2023 Gas Allocation Dollars	2024 Gas Allocation Dollars
23	106 Hub to Microsoft Teams	$9,269	0	1	$0	$9,269	$0	$2,813
24	136A display replacement	$1,212	0	1	$0	$1,212	$0	$368
25	207 Hub to Microsoft Teams	$9,269	0	1	$0	$9,269	$0	$2,813
26	207 Hub to Microsoft Teams	$9,316	0	1	$0	$9,316	$0	$2,827
27	50" Hub	$9,157	4	0	$36,628	$0	$11,750	$0
28	49" Display Monitor	$3,499	0	1	$0	$3,499	$0	$1,062
29	55" Display	$6,858	1	0	$6,858	$0	$2,200	$0
30	50" LED Public Display Monitor	$2,346	7	0	$16,422	$0	$5,268	$0
31	55" LED Display	$15,556	0	1	$0	$15,556	$0	$4,721
32	50" Surface Hubs	$9,157	4	0	$36,628	$0	$11,750	$0
33	55' LED Public Display Monitor	$1,092	0	1	$0	$1,092	$0	$331
34	85" Hub	$16,679	2	0	$33,358	$0	$10,701	$0
35	85" Surface hub	$16,679	2	0	$33,358	$0	$10,701	$0
36	5 Channels 70K Display	$2,908	2	0	$5,816	$0	$1,866	$0
37	Cisco Phone System	$943,441	1	0	$943,441	$0	$302,656	$0
38	Conference Center Room	$3,722	1	0	$3,722	$0	$1,194	$0
39	Conference Center Room	$9,852	1	0	$9,852	$0	$3,161	$0
40	Conference Room	$26,253	1	0	$26,253	$0	$8,422	$0
41	Conference Room	$7,323	0	1	$0	$7,323	$0	$2,223
42	Conference Room	$7,343	0	1	$0	$7,343	$0	$2,229
43	Conference Room	$7,029	0	1	$0	$7,029	$0	$2,133
44	Conference Room	$7,029	0	1	$0	$7,029	$0	$2,133
45	Conference Room	$8,393	0	1	$0	$8,393	$0	$2,547
46	Covert Display replacement with cart 32"	$14,442	0	1	$0	$14,442	$0	$4,383
47	Crew Room	$3,722	1	0	$3,722	$0	$1,194	$0
48	Crew Room	$3,722	1	0	$3,722	$0	$1,194	$0
49	Digital signage	$1,749	0	1	$0	$1,749	$0	$531
50	Digital Signage refresh Phase 4	$4,293	1	0	$4,293	$0	$1,377	$0
51	Digital Signage 55"	$1,052	7	0	$7,364	$0	$2,362	$0
52	Digital Signage E498	$1,454	7	0	$10,178	$0	$3,265	$0
53	Digital Signage refresh - LCD Displays	$1,454	7	0	$10,178	$0	$3,265	$0
54	Digital signage replacement	$2,310	0	1	$0	$2,310	$0	$701
55	Display replacement	$3,093	0	1	$0	$3,093	$0	$939
56	Display replacement	$3,305	0	1	$0	$3,305	$0	$1,003
57	Display replacement - 49" TV	$1,118	0	1	$0	$1,118	$0	$339
58	Eight (8) mid size conference rooms	$41,107	1	0	$41,107	$0	$13,187	$0
59	Floor/Wall Mounts	$21,000	1	0	$21,000	$0	$6,737	$0
60	Gas Control Hub replacements	$35,327	0	1	$0	$35,327	$0	$10,722
61	Gen 1 Replacements	$32,212	0	11	$0	$354,332	$0	$107,540
62	Hardware	$2,815	1	0	$2,815	$0	$903	$0
63	Hub to Microsoft Teams	$9,269	0	1	$0	$9,269	$0	$2,813
64	HUBs New Installs	$19,004	10	0	$190,040	$0	$60,965	$0
65	Hubs and stands	$18,175	0	1	$0	$18,175	$0	$5,516
66	Hub and Stand	$11,093	0	1	$0	$11,093	$0	$3,367
67	Hub replaced with Microsoft Teams Room	$7,243	0	1	$0	$7,243	$0	$2,198
68	Hub replaced with Microsoft Teams Room	$7,243	0	1	$0	$7,243	$0	$2,198
69	Hub replaced with Microsoft Teams Room	$7,373	0	1	$0	$7,373	$0	$2,238
70	Hub replaced with Microsoft Teams Room	$7,373	0	1	$0	$7,373	$0	$2,238
71	Hub Replacement	$7,243	0	1	$0	$7,243	$0	$2,198
72	Hub Stand	$2,699	0	9	$0	$24,291	$0	$7,372
73	Hub to Microsoft Teams	$8,971	0	1	$0	$8,971	$0	$2,723
74	Hub to Microsoft Teams	$9,269	0	1	$0	$9,269	$0	$2,813
75	Hub to Microsoft Teams	$6,156	0	1	$0	$6,156	$0	$1,868
76	JRC	$1,617	0	1	$0	$1,617	$0	$491
77	LCD Projector	$2,695	0	1	$0	$2,695	$0	$818
78	LED Commercial TV	$1,447	0	1	$0	$1,447	$0	$439
79	Microsoft Surface hub stand	$2,676	0	1	$0	$2,676	$0	$812
80	Microsoft Surface hub	$11,773	0	1	$0	$11,773	$0	$3,573
81	Microsoft Teams Room	$6,767	0	1	$0	$6,767	$0	$2,054
82	Monitor Replacement	$1,132	0	1	$0	$1,132	$0	$344
83	Microsoft Teams Room	$9,151	0	1	$0	$9,151	$0	$2,777
84	Microsoft Teams Room	$7,008	0	1	$0	$7,008	$0	$2,127
85	Microsoft Teams Room	$8,501	0	1	$0	$8,501	$0	$2,580
86	Microsoft Teams Room 75"	$3,452	0	2	$0	$6,904	$0	$2,095
87	New Hub Installation	$2,093	1	0	$2,093	$0	$671	$0
88	NOC/SOC	$44,925	1	0	$44,925	$0	$14,412	$0
89	PolyCom UC Group 14	$4,621	1	0	$4,621	$0	$1,482	$0
90	PolyCom UC Group 12 - equipment	$4,621	1	0	$4,621	$0	$1,482	$0
91	PolyCom UC Group 18 - equipment	$4,621	1	0	$4,621	$0	$1,483	$0
92	PolyCom UC Group 18 - equipment	$4,621	1	0	$4,621	$0	$1,483	$0
93	PolyCom UC Group 18 - equipment	$4,621	1	0	$4,621	$0	$1,483	$0
94	PolyCom UC Group 18 - equipment	$4,621	1	0	$4,621	$0	$1,483	$0
95	PolyCom UC Group 18 - equipment	$4,621	1	0	$4,621	$0	$1,482	$0
96	PolyCom UC Group 18 - equipment	$4,621	1	0	$4,621	$0	$1,482	$0
97	PolyCom UG Group 4 - Equipment	$4,899	1	0	$4,899	$0	$1,571	$0
98	PolyCom UG Group 5 - Equipment	$14,696	1	0	$14,696	$0	$4,714	$0
99	PolyCom UC Group 8 - Equipment	$4,354	1	0	$4,354	$0	$1,397	$0
100	PolyCom UC Group 8 - Equipment	$4,354	1	0	$4,354	$0	$1,397	$0
101	PolyCom UC Group 8 - Equipment	$4,354	1	0	$4,354	$0	$1,397	$0
102	PolyCom UC Group 8 - Equipment	$4,354	1	0	$4,354	$0	$1,397	$0
103	PolyCom UC Group 8 - Equipment	$4,354	1	0	$4,354	$0	$1,397	$0
104	PolyCom UC Group 8 - Equipment	$4,354	1	0	$4,354	$0	$1,397	$0
105	PolyCom UC Group 8 - Equipment	$4,354	1	0	$4,354	$0	$1,397	$0
106	PolyCom UC Group 8 - Equipment	$4,354	1	0	$4,354	$0	$1,397	$0
107	PolyCom UC Group 8 - Equipment	$4,354	1	0	$4,354	$0	$1,397	$0
108	Projector replacement	$4,613	0	1	$0	$4,613	$0	$1,400
109	Projector replacement	$2,408	0	1	$0	$2,408	$0	$731
110	Projector Replacement	$10,551	0	1	$0	$10,551	$0	$3,202
111	Small Conference Room	$7,494	1	0	$7,494	$0	$2,404	$0
112	Surface Hubs	$2,100	0	11	$0	$23,100	$0	$7,011
113	Surface Hub 50"	$30,663	1	0	$30,663	$0	$9,837	$0
114	Surface Hub 85"	$24,435	1	0	$24,435	$0	$7,839	$0
115	Surface hub 85"	$27,368	0	1	$0	$27,368	$0	$8,306
116	Surface Hub	$12,186	0	1	$0	$12,186	$0	$3,698
117	UC Group 2 equipment	$9,434	1	0	$9,434	$0	$3,026	$0
118	UC System	$6,314	0	1	$0	$6,314	$0	$1,916
119	UPS	$4,027	1	0	$4,027	$0	$1,292	$0
120	Wellness Room	$3,722	1	0	$3,722	$0	$1,194	$0
121	Software, labor, contractor and overhead and other costs				$170,512	$338,192	$54,700	$102,641
122	**Total Gas Allocation**				$1,839,809	$1,110,108	**$590,211**	**$336,918**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Programs
Projected Gas and Common Capital Expenditures
For the Projected Year 2025 and Test Year Ending October 31, 2026
For the Historical Year 2023 and Projected Year 2024

Case No.: U-21806
Exhibit No.: A-22 (SHB-7)
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Witness: SHBaker
Date: December 2024

ARP-CORE Network Upgrade

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**Total Test Year Dollars**	**Gas Allocation Dollars**
1	Core Switch A	$80,000	0	4	$0	$320,000	$266,667	$83,813
2	Core Switch C	$40,000	0	4	$0	$160,000	$133,333	$41,907
3	Core Switch E	$1,000	0	20	$0	$20,000	$16,667	$5,238
4	Software, labor, contractor and overhead and other costs				$0	$39,800	$33,167	$10,424
5	**Total Gas Allocation**				$0	$539,800	**$449,833**	**$141,383**

	Units	**Avg. Unit Cost**	**Total 2023 Units**	**Total 2024 Units**	**Total 2023 Dollars**	**Total 2024 Dollars**	**2023 Gas Allocation Dollars**	**2024 Gas Allocation Dollars**
6	Software, labor, contractor and overhead and other costs				$26,320	$0	$8,444	$0
7	**Total Gas Allocation**				$26,320	$0	**$8,444**	**$0**

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ARP-Cyber Security

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**Total Test Year Dollars**	**Gas Allocation Dollars**
1	Firewalls Replacement	$9,500	39	29	$370,500	$275,500	$291,333	$140,510
2	Sensor Replacement	$14,000	0	7	$0	$98,000	$81,667	$39,388
3	Software, labor, contractor and overhead and other costs				$80,000	$80,000	$80,000	$38,584
4	**Total Gas Allocation**				$450,500	$453,500	**$453,000**	**$218,482**

	Units	**Avg. Unit Cost**	**Total 2023 Units**	**Total 2024 Units**	**Total 2023 Dollars**	**Total 2024 Dollars**	**2023 Gas Allocation Dollars**	**2024 Gas Allocation Dollars**
5	Active Fiber Cable	$482	0	2	$0	$964	$0	$447
6	Badge Printer Replacement	$10,000	0	1	$0	$10,000	$0	$4,639
7	Firewalls Replacement	$9,500	0	20	$0	$190,000	$0	$88,141
8	Hardware Replacement	$3,005	0	1	$0	$3,005	$0	$1,394
9	Monthly Sub License	$7,264	0	2	$0	$14,529	$0	$6,740
10	Multimode SR	$285	0	104	$0	$29,616	$0	$13,739
11	Networks	$1,099	0	46	$0	$50,572	$0	$23,460
12	Networks	$108	0	46	$0	$4,986	$0	$2,313
13	Networks	$163	0	46	$0	$7,479	$0	$3,470
14	Networks	$295	0	1	$0	$295	$0	$137
15	Networks	$295	0	1	$0	$295	$0	$137
16	QRadar	$28,501	0	1	$0	$28,501	$0	$13,222
17	Software License	$3,665	0	2	$0	$7,330	$0	$3,400
18	Software License	$40,606	0	2	$0	$81,211	$0	$37,674
19	Software, labor, contractor and overhead and other costs				$0	$39,419	$0	$18,286
20	**Total Gas Allocation**				$0	$468,202	**$0**	**$217,199**

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ARP-Field Device Asset Mgmt

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**Total Test Year Dollars**	**Gas Allocation Dollars**
	Replacemements							
1	Field Devices CF33 w/acce	$4,912	248	1294	$1,218,288	$6,356,710	$5,500,307	$1,728,746
2	Field Devices CF55 w/acces	$4,003	290	31	$1,160,945	$124,101	$296,908	$93,318
3	CF33 accessories					$91	$76	$24
	New Purchases							
4	Field Devices CF33	$4,912	170	170	$835,117	$835,117	$835,117	$262,477
5	Field Devices CF55	$4,003	30	30	$120,098	$120,098	$120,098	$37,747
6	Accessories				$42,041	$44,786	$44,329	$13,932
7	Software, labor, contractor and overhead and other costs				$80,556	$197,568	$178,066	$55,966
8	**Total Gas Allocation**				$3,457,044	$7,678,471	**$6,974,900**	**$2,192,211**

	Units	**Avg. Unit Cost**	**Total 2023 Units**	**Total 2024 Units**	**Total 2023 Dollars**	**Total 2024 Dollars**	**2023 Gas Allocation Dollars**	**2024 Gas Allocation Dollars**
	Replacements							
9	Field Devices CF33 w/acce	$4,474	524	0	$2,344,418	$0	$752,089	$0
10	Field Devices CF33 w/acce	$4,912	0	591	$0	$2,903,258	$0	$881,139
11	Field Devices CF55 w/acces	$0	0	0	$0	$0	$0	$0
12	Field Devices CF55 w/acces	$4,003	0	38	$0	$152,124	$0	$46,170
13	Field Devices Getac A140	$4,718	191	0	$901,149	$0	$289,089	$0
14	Field Devices Getac A140	$4,621	0	49	$0	$226,406	$0	$68,714
15	CF33 accessories				$10,655	$26,434	$3,418	$8,023
	New Purchases							
16	Field Devices CF33	$4,912	0	86	$0	$422,471	$0	$128,220
17	Field Devices CF55	$4,003	0	20	$0	$80,065	$0	$24,300
18	Field Devices Getac A140	$4,621	0	1	$0	$4,621	$0	$1,402
19	Accessories				$0	$32,846	$0	$9,969
20	Software, labor, contractor and overhead and other costs				$17,618	$95,647	$5,652	$29,029
21	**Total Gas Allocation**				$3,273,840	$3,943,872	**$1,050,248**	**$1,196,965**

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ARP-Infoblox

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**Total Test Year Dollars**	**Gas Allocation Dollars**
1	Network Manager A	$41,330	4	1	$165,321	$41,330	$61,995	$29,900
2	Network Manager B	$2,812	4	6	$11,250	$16,874	$15,937	$7,686
3	Network Manager C	$1,419	4	4	$5,676	$5,676	$5,676	$2,737
4	Network Manager D	$28,736	8	0	$229,888	$0	$38,315	$18,479
5	Network Manager D	$28,260	0	1	$0	$28,260	$23,550	$11,358
6	Network Manager E	$2,812	8	1	$22,499	$2,812	$6,093	$2,939
7	Network Manager F	$1,419	8	5	$11,351	$7,094	$7,804	$3,764
8	Network Manager G	$13,336	4	1	$53,345	$13,336	$20,004	$9,648
9	Network Manager H	$1,522	5	1	$7,612	$1,522	$2,537	$1,224
10	Network Manager I	$40,450	1	0	$40,450	$0	$6,742	$3,252
11	Network Manager J	$100,162	1	0	$100,162	$0	$16,694	$8,051
12	Network Manager K	$1,522	8	5	$12,180	$7,612	$8,374	$4,039
13	Network Manager L	$2,812	2	3	$5,625	$8,437	$7,968	$3,843
14	Network Manager M	$221,926	1	0	$221,926	$0	$36,988	$17,839
15	Network Manager N	$1,522	3	1	$4,567	$1,522	$2,030	$979
16	Network Manager O	$2,812	1	1	$2,812	$2,812	$2,812	$1,356
17	Antenas				$83,550	$60,150	$64,050	$30,891
18	**Total Gas Allocation**				$978,213	$197,440	**$327,569**	**$157,986**

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ARP-Local Area Network

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**Total Test Year Dollars**	**Gas Allocation Dollars**
1	LAN Switch A	$20,512	2	8	$41,024	$164,096	$143,584	$69,251
2	LAN Switch B	$8,132	7	4	$56,924	$32,528	$36,594	$17,649
3	LAN Switch C	$6,743	4	8	$26,971	$53,942	$49,446	$23,848
4	LAN Switch D	$1,290	5	14	$6,448	$18,055	$16,120	$7,775
5	LAN Switch E	$5,631	4	4	$22,523	$22,523	$22,523	$10,863
6	LAN Switch F	$996	5	20	$4,980	$19,920	$17,430	$8,406
7	LAN Switch G	$1,474	8	8	$11,792	$11,792	$11,792	$5,687
8	LAN Switch H	$12,270	4	4	$49,081	$49,081	$49,081	$23,672
9	LAN Switch I	$1,006	0	2	$0	$2,013	$1,677	$809
10	Wireless Access Points	$1,052	5	1	$5,258	$1,052	$1,753	$845
11	Software, labor, contractor and overhead and other costs				$95,435	$136,110	$129,331	$62,376
12	**Total Gas Allocation**				$320,435	$511,110	**$479,331**	**$231,181**

	Units	**Avg. Unit Cost**	**Total 2023 Units**	**Total 2024 Units**	**Total 2023 Dollars**	**Total 2024 Dollars**	**2023 Gas Allocation Dollars**	**2024 Gas Allocation Dollars**
13	F5	$90,113	0	2	$0	$180,226	$0	$83,607
14	LAN Switch A	$6,415	40	0	$256,609	$0	$112,703	$0
15	LAN Switch B	$2,873	520	0	$1,493,726	$0	$656,044	$0
16	LAN Switch C	$2,533	150	0	$380,010	$0	$166,900	$0
17	LAN Switch D	$1,215	290	0	$352,452	$0	$154,797	$0
18	LAN Switch E	$1,513	90	0	$136,147	$0	$59,796	$0
19	LAN Switch F	$174,151	1	0	$174,151	$0	$76,487	$0
20	MX Router	$26,986	0	3	$0	$80,958	$0	$37,556
21	Network Manager A - E	$7,900	0	23	$0	$181,700	$0	$84,291
22	Network Manager K - O	$54,000	0	1	$0	$54,000	$0	$25,051
23	Network Server	$47,870	0	3	$0	$143,610	$0	$66,621
24	Optic Cables	$61,542	1	0	$61,542	$0	$27,029	$0
25	Plixer	$8,571	0	7	$0	$59,997	$0	$27,833
26	Power Supply Units	$344	0	55	$0	$18,920	$0	$8,777
27	Wireless Access Points	$1,559	764	0	$1,191,076	$0	$523,121	$0
28	Wireless Access Points	$1,594	0	395	$0	$629,476	$0	$292,014
29	Wireless Controllers	$3,332	0	161	$0	$536,452	$0	$248,860
30	Software, labor, contractor and overhead and other costs				$800,034	$1,389,399	$351,375	$644,542
31	**Total Gas Allocation**				$4,845,746	$3,274,738	**$2,128,252**	**$1,519,151**

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ARP-OT Support Gas

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**Total Test Year Dollars**	**Gas Allocation Dollars**
1	Cellular Routers	$1,500	0	10	$0	$15,000	$12,500	$12,500
2	Field Switches (BRS32)	$1,568	0	30	$0	$47,025	$39,188	$39,188
3	Field Switches (GRS 1042)	$528	0	3	$0	$1,584	$1,320	$1,320
4	Firewalls	$150,000	1	0	$150,000	$0	$25,000	$25,000
5	Firewalls	$22,440	0	20	$0	$448,800	$374,000	$374,000
6	Head-End Devices	$5,000	0	4	$0	$20,000	$16,667	$16,667
7	Hyperconverged Server	$375,000	1	0	$375,000	$0	$62,500	$62,500
8	Hyperconverged Server	$28,875	0	8	$0	$231,000	$192,500	$192,500
9	Hyperconverged Server	$67,000	0	18	$0	$1,206,000	$1,005,000	$1,005,000
10	Industrial Panel PCs	$6,500	0	17	$0	$110,500	$92,083	$92,083
11	Modems	$93,750	1	0	$93,750	$0	$15,625	$15,625
12	Routers	$93,750	1	0	$93,750	$0	$15,625	$15,625
13	Servers	$37,500	1	0	$37,500	$0	$6,250	$6,250
14	Switches	$112,500	1	0	$112,500	$0	$18,750	$18,750
15	Switches	$4,455	0	26	$0	$115,830	$96,525	$96,525
16	Thin Clients & Monitors	$1,200	0	16	$0	$19,200	$16,000	$16,000
17	Antenas				$116,678	$550,905	$478,534	$478,534
18	**Total Gas Allocation**				$979,178	$2,765,844	**$2,468,066**	**$2,468,066**

	Units	**Avg. Unit Cost**	**Total 2023 Units**	**Total 2024 Units**	**Total 2023 Dollars**	**Total 2024 Dollars**	**2023 Gas Allocation Dollars**	**2024 Gas Allocation Dollars**
19	Cisco C8500	$36,677	0	2	$0	$73,353	$0	$73,353
20	Cisco Connected Grid 2G/3G/4G LTE GRWIC	$46,009	1	0	$46,009	$0	$46,009	$0
21	DataCom Tap	$2,064	0	5	$0	$10,322	$0	$10,322
22	F5 Hardware	$5,881	0	10	$0	$58,813	$0	$58,813
23	Firewalls	$11,217	0	27	$0	$302,870	$0	$302,870
24	Firewalls	$53,074	0	2	$0	$106,148	$0	$106,148
25	GPC Clocks	$1,427	0	2	$0	$2,853	$0	$2,853
26	Hyper-Convered Solution	$34,366	0	4	$0	$137,463	$0	$137,463
27	Juniper Switches PRM - 2024 ARP PRM - NTXN240	$12,665	0	2	$0	$25,330	$0	$25,330
28	Juniper Switches GRM - 2024 ARP GRM - NTXN214	$12,953	0	2	$0	$25,907	$0	$25,907
29	Juniper Switches prm - NWQV081	$6,491	0	6	$0	$38,944	$0	$38,944
30	Juniper Switches grm - NWQV118	$6,491	0	6	$0	$38,944	$0	$38,944
31	Master Terminal Unit	$2,872	0	35	$0	$100,515	$0	$100,515
32	Network Adapters	$196	0	20	$0	$3,929	$0	$3,929
33	Wyse Thin Clients	$525	0	10	$0	$5,250	$0	$5,250
34	Software, labor, contractor and overhead and other costs				$198,988	$102,587	$198,988	$102,587
35	**Total Gas Allocation**				$244,997	$1,033,227	**$244,997**	**$1,033,227**

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ARP-Physical Security

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	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**Total Test Year Dollars**	**Gas Allocation Dollars**
1	Cabling/Misc Equipment	$10,000	12	13	$120,000	$130,000	$128,333	$40,335
2	Cameras	$3,000	117	0	$351,000	$0	$58,500	$18,387
3	Cameras	$3,500	0	163	$0	$570,500	$475,417	$149,423
4	Lift Charge	$5,000	12	13	$60,000	$65,000	$64,167	$20,168
5	Logistics & Operation Expense	$4,000	12	13	$48,000	$52,000	$51,333	$16,134
6	NVR/Monitor	$35,000	12	0	$420,000	$0	$70,000	$22,001
7	NVR/Monitor	$37,000	0	13	$0	$481,000	$400,833	$125,982
8	Software, labor, contractor and overhead and other costs				$903,740	$1,174,862	$1,129,675	$355,057
9	**Total Gas Allocation**				$1,902,740	$2,473,362	**$2,378,258**	**$747,487**

	Units	**Avg. Unit Cost**	**Total 2023 Units**	**Total 2024 Units**	**Total 2023 Dollars**	**Total 2024 Dollars**	**2023 Gas Allocation Dollars**	**2024 Gas Allocation Dollars**
10	3rd Party Vendor	$29,637	0	1	$0	$29,637	$0	$8,995
11	Cabling/Misc Equipment	$10,216	0	6	$0	$61,296	$0	$18,603
12	Cameras	$2,859	159	0	$454,581	$0	$145,830	$0
13	Cameras	$1,175	0	171	$0	$200,944	$0	$60,986
14	Card Access (SIO & SCP)	$14,291	1	0	$14,291	$0	$4,585	$0
15	Card Access (SIO & SCP)	$1,481	0	92	$0	$136,233	$0	$41,347
16	Intercom	$1,607	6	0	$9,641	$0	$3,093	$0
17	Lift Charge	$27,960	1	0	$27,960	$0	$8,970	$0
18	Lift Charge	$3,643	0	4	$0	$14,573	$0	$4,423
19	Logistics & Operation Expense	$2,470	0	3	$0	$7,409	$0	$2,249
20	NVR/Monitor	$19,822	10	0	$198,224	$0	$63,590	$0
21	NVR/Monitor	$41,387	0	5	$0	$206,936	$0	$62,805
22	Accessories				$93,838	$0	$30,103	$0
23	Software, labor, contractor and overhead and other costs				$639,422	$894,675	$205,127	$271,534
24	**Total Gas Allocation**				$1,437,957	$1,551,703	**$461,297**	**$470,942**

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ARP-Printer Asset Management

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**Total Test Year Dollars**	**Gas Allocation Dollars**
1	Fax Board	$541	2	0	$1,081	$0	$180	$57
2	IM C300	$1,767	75	3	$132,525	$5,301	$26,505	$8,331
3	IM C2500	$5,235	16	2	$83,765	$10,471	$22,686	$7,130
4	IM C3010	$5,536	74	0	$409,664	$0	$68,277	$21,460
5	IM C3510	$6,137	40	2	$245,480	$12,274	$51,142	$16,074
6	IM C6010	$7,243	37	0	$267,990	$0	$44,665	$14,038
7	MPC W2201	$8,204	49	8	$402,016	$65,635	$121,699	$38,250
8	MP W6700 Plotter	$10,007	1	0	$10,007	$0	$1,668	$524
9	Ricoh PRO C5300	$34,426	0	1	$0	$34,426	$28,689	$9,017
10	SPC 8200	$6,807	2	0	$13,615	$0	$2,269	$713
11	Accessories				$2,352	$527	$831	$261
12	Software, labor, contractor and overhead and other costs				$43,365	$2,205	$9,065	$2,849
13	**Total Gas Allocation**				$1,611,861	$130,839	**$377,676**	**$118,704**

	Units	**Avg. Unit Cost**	**Total 2023 Units**	**Total 2024 Units**	**Total 2023 Dollars**	**Total 2024 Dollars**	**2023 Gas Allocation Dollars**	**2024 Gas Allocation Dollars**
14	Fax Board	$505	6	0	$3,030	$0	$972	$0
15	IM C300	$1,767	20	71	$35,340	$125,457	$11,337	$38,076
16	IM C2500	$5,235	6	14	$31,412	$73,295	$10,077	$22,245
17	IM C3010	$5,536	29	0	$160,555	$0	$51,506	$0
18	IM C3010	$5,536	0	8	$0	$44,288	$0	$13,441
19	IM C3510	$6,137	2	74	$12,274	$454,138	$3,937	$137,831
20	IM C6010	$7,243	7	27	$50,701	$195,560	$16,265	$59,353
21	MPC W2201	$8,204	5	0	$41,020	$0	$13,159	$0
22	MPC W2201	$8,404	0	12	$0	$100,848	$0	$30,607
23	Software, labor, contractor and overhead and other costs				($1,640)	$43,693	($526)	$13,261
24	**Total Gas Allocation**				$332,691	$1,037,279	**$106,727**	**$314,814**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Programs
Projected Gas and Common Capital Expenditures
For the Projected Year 2025 and Test Year Ending October 31, 2026
For the Historical Year 2023 and Projected Year 2024

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ARP-Radio

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**Total Test Year Dollars**	**Gas Allocation Dollars**
1	800Mhz Mobile Front Mount	$2,750	450	450	$1,237,500	$1,237,500	$1,237,500	$596,846
2	Bi-Directional Amp	$1,600	10	10	$16,000	$16,000	$16,000	$7,717
3	Conventional Repeaters Hardware	$30,000	0	1	$0	$30,000	$25,000	$12,058
4	Havis Boxes	$3,419	150	165	$512,850	$564,135	$555,588	$267,960
5	Modem	$2,500	0	10	$0	$25,000	$20,833	$10,048
6	Software, labor, contractor and overhead and other costs				$622,577	$635,681	$633,497	$305,536
7	**Total Gas Allocation**				$2,388,927	$2,508,316	**$2,488,418**	**$1,200,164**

	Units	**Avg. Unit Cost**	**Total 2023 Units**	**Total 2024 Units**	**Total 2023 Dollars**	**Total 2024 Dollars**	**2023 Gas Allocation Dollars**	**2024 Gas Allocation Dollars**
8	210lb Break Strength Polyline	$91	0	1	$0	$91	$0	$42
9	800Mhz Mobile Front Mount	$620	0	100	$0	$61,997	$0	$28,760
10	800Mhz Portable Radios	$1,909	0	100	$0	$190,894	$0	$88,556
11	Antanas	$43	0	50	$0	$2,139	$0	$992
12	Battery Conditioners	$4,393	0	1	$0	$4,393	$0	$2,038
13	Bi-Directional Amp	$14,286	0	1	$0	$14,286	$0	$6,627
14	Bi-Directional Amp	$29,860	1	0	$29,860	$0	$13,115	$0
15	Bi-Directional Amp	$12,745	0	1	$0	$12,745	$0	$5,913
16	Bi-Directional Amp	$1,606	0	1	$0	$1,606	$0	$745
17	Bi-Directional Amp	$14,532	0	1	$0	$14,532	$0	$6,741
18	Bi-Directional Amp	$83,530	1	0	$83,530	$0	$36,686	$0
19	Bi-Directional Amp	$2,500	0	0	$0	$0	$0	$0
20	Bi-Directional Amp	$1,590	0	10	$0	$15,900	$0	$7,376
21	Bi-Directional Amp	$1,697	1	0	$1,697	$0	$745	$0
22	Bi-Directional Amp	$11,156	0	1	$0	$11,156	$0	$5,175
23	Control Stations	$2,174	0	250	$0	$543,455	$0	$252,109
24	Cutoff Saw Tool	$175	0	1	$0	$175	$0	$81
25	Distributed Antenna System	$574,142	1	0	$574,142	$0	$252,163	$0
26	Drone and Accessories	$6,246	0	1	$0	$6,246	$0	$2,898
27	Havis Boxes	$42,400	0	1	$0	$42,400	$0	$19,669
28	Havis Boxes	$35,000	0	0	$0	$0	$0	$0
29	Havis Plates, Fillers	$10	0	60	$0	$585	$0	$271
30	Installation Accessories	$585	0	100	$0	$58,500	$0	$27,138
31	Lighting Refresh	$64,940	0	1	$0	$64,940	$0	$30,126
32	Met Tower	$21,200	0	2	$0	$42,400	$0	$19,669
33	Met Tower	$63,000	0	3	$0	$189,000	$0	$87,677
34	Miscellaneous Parts	$1,514	0	2	$0	$3,028	$0	$1,405
35	Plenum Air Dielectric Kit	$18,842	0	1	$0	$18,842	$0	$8,741
36	Plenum Air Dielectric Kit	$12,258	0	1	$0	$12,258	$0	$5,686
37	Power Supply	$242	0	1	$0	$242	$0	$112
38	Programming Accessories	$314	0	10	$0	$3,138	$0	$1,456
39	Radio Activation	$250	0	350	$0	$87,500	$0	$40,591
40	Radio Network Refresh Hardware	$5,168	0	1	$0	$5,168	$0	$2,397
41	Scanners	$3,813	1	0	$3,813	$0	$1,675	$0
42	Scanners	$4,525	0	4	$0	$18,099	$0	$8,396
43	Repeater	$3,376	0	1	$0	$3,376	$0	$1,566
44	Wallmount Accessories	$20,910	0	1	$0	$20,910	$0	$9,700
45	Watt Meter	$1,376	0	7	$0	$9,632	$0	$4,468
46	Software, labor, contractor and overhead and other costs				$41,817	($124,301)	$18,366	($57,663)
47	**Total Gas Allocation**				$734,859	$1,335,332	**$322,750**	**$619,460**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Programs
Projected Gas and Common Capital Expenditures
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ARP-Server and Storage

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**Total Test Year Dollars**	**Gas Allocation Dollars**
1	Hyperscale Expansion	$106,503	1	0	$106,503	$0	$17,751	$5,579
2	Nutanix xc640	$137,109	8	14	$1,096,874	$1,919,530	$1,782,420	$560,215
3	Labor, contractor and overhead and other costs				$536,200	$383,000	$408,534	$128,402
4	**Total Gas Allocation**				$1,739,577	$2,302,530	**$2,208,705**	**$694,196**

	Units	**Avg. Unit Cost**	**Total 2023 Units**	**Total 2024 Units**	**Total 2023 Dollars**	**Total 2024 Dollars**	**2023 Gas Allocation Dollars**	**2024 Gas Allocation Dollars**
5	Connectrix SAN Switches	$199,977	1	0	$199,977	$0	$64,153	$0
6	Hyperscale Expansion	$494,608	1	0	$494,608	$0	$158,670	$0
7	Network	$38,928	1	0	$38,928	$0	$12,488	$0
8	Nutanix xc640	$328,014	1	0	$328,014	$0	$105,227	$0
9	Nutanix xc740xd	$32,946	0	20	$0	$658,929	$0	$199,985
10	Power Distribution Unit	$15,525	1	0	$15,525	$0	$4,980	$0
11	Antenas	$168,274	1	0	$168,274	$0	$53,982	$0
12	SFP	$51	0	40	$0	$2,040	$0	$619
13	Labor, contractor and overhead and other costs				$1,021,880	$113,144	$327,819	$34,339
14	**Total Gas Allocation**				$2,267,206	$774,113	**$727,320**	**$234,943**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Asset Refresh Programs
Projected Gas and Common Capital Expenditures
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ARP-Workstation Asset Mgmt

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Units	**Avg. Unit Cost**	**Total 2025 Units**	**Total 2026 Units**	**Total 2025 Dollars**	**Total 2026 Dollars**	**Total Test Year Dollars**	**Gas Allocation Dollars**
	Replacements							
1	Desktops	$1,378	35	95	$48,230	$130,910	$117,130	$36,814
2	HP Desktop Bundled	$4,049	67	41	$271,296	$166,017	$183,564	$57,694
3	Laptop	$1,908	2533	1787	$4,832,964	$3,409,596	$3,646,824	$1,146,197
4	Laptop 15"	$3,037	654	273	$1,986,133	$829,074	$1,021,917	$321,188
5	RT Mount Device	$8,480	20	15	$169,600	$127,200	$134,267	$42,200
6	Tablets	$2,644	67	4	$177,171	$10,577	$38,343	$12,051
7	Accessories				$51,443	$97,133	$89,518	$28,135
	New Purchases							
8	24" Monitors	$233	120	120	$27,984	$27,984	$27,984	$8,795
9	Apple Tablets	$1,025	1	1	$1,025	$1,025	$1,025	$322
10	Desktop (MT)	$1,378	14	14	$19,292	$19,292	$19,292	$6,063
11	SFF Desktop	$1,246	8	8	$9,964	$9,964	$9,964	$3,132
12	HP Desktop	$4,049	5	5	$20,246	$20,246	$20,246	$6,363
13	HP laptop (15"/16")	$3,037	60	60	$182,214	$182,214	$182,214	$57,270
14	Laptop (14")	$1,908	302	302	$576,216	$576,216	$576,216	$181,105
15	Antenas	$1,942	3	3	$5,827	$5,827	$5,827	$1,831
16	Teams Monitors	$323	280	280	$90,524	$90,524	$90,524	$28,452
17	Accessories				$64,000	$64,000	$64,000	$20,115
18	Shipping and Handling/other fees				$2,708	$2,708	$2,708	$851
19	Software, labor, contractor and overhead and other costs				$445,632	$299,771	$324,081	$101,859
20	**Total Gas Allocation**				$8,982,469	$6,070,278	**$6,555,643**	**$2,060,439**

	Units	**Avg. Unit Cost**	**Total 2023 Units**	**Total 2024 Units**	**Total 2023 Dollars**	**Total 2024 Dollars**	**2023 Gas Allocation Dollars**	**2024 Gas Allocation Dollars**
	Replacements							
21	Desktops	$1,314	437	0	$574,332	$0	$184,246	$0
22	Desktops	$1,484	0	160	$0	$237,440	$0	$72,063
23	SFF Desktop	$1,251	10	0	$12,508	$0	$4,013	$0
24	SFF Desktop	$1,385	0	116	$0	$160,668	$0	$48,763
25	HP Desktop Bundled	$4,419	77	0	$340,277	$0	$109,161	$0
26	HP Desktop Bundled	$4,505	0	75	$0	$337,875	$0	$102,545
27	HP Desktops OT	$6,042	0	65	$0	$392,730	$0	$119,194
28	Laptop	$1,764	1253	0	$2,209,853	$0	$708,921	$0
29	Laptop	$1,813	0	835	$0	$1,513,521	$0	$459,354
30	Laptop	$2,740	189	0	$517,828	$0	$166,119	$0
31	HP Laptop bundled	$3,577	77	0	$275,441	$0	$88,362	$0
32	HP Laptop bundled	$3,248	0	518	$0	$1,682,635	$0	$510,680
33	Macs	$2,828	0	3	$0	$8,483	$0	$2,575
34	Rugged Devices	$4,152	104	0	$431,775	$0	$138,513	$0
35	RT Mount Device	$8,480	0	51	$0	$432,480	$0	$131,258
36	Surface Pro Laptops	$2,257	0	30	$0	$67,709	$0	$20,550
37	Tablets	$2,247	0	16	$0	$35,952	$0	$10,911
38	Tablets	$1,825	6	0	$10,952	$0	$3,513	$0
39	Teams Monitors	$323	0	105	$0	$33,947	$0	$10,303
40	Accessories				$267,836	$200,079	$85,922	$60,724
	New Purchases							
41	24" Monitors	$233	79	0	$18,423	$0	$5,910	$0
42	Apple Macbook	$2,833	2	0	$5,667	$0	$1,818	$0
43	Apple Tablets	$1,025	0	1	$0	$1,025	$0	$311
44	Desktop	$1,314	11	0	$14,457	$0	$4,638	$0
45	Desktop	$1,484	0	2	$0	$2,968	$0	$901
46	HP Desktop	$4,419	1	0	$4,419	$0	$1,418	$0
47	HP Desktop	$4,505	0	4	$0	$18,020	$0	$5,469
48	HP laptop	$2,740	23	0	$63,016	$0	$20,216	$0
49	HP laptop	$3,248	0	30	$0	$97,450	$0	$29,576
50	Laptop	$1,764	70	0	$123,456	$0	$39,605	$0
51	Laptop	$1,813	0	145	$0	$262,827	$0	$79,768
52	Rugged Devices - Getac	$4,718	45	0	$212,313	$0	$68,110	$0
53	Rugged Devices - Panasonic CF33	$4,152	113	0	$469,140	$0	$150,500	$0
54	Semi-Rugged Devices - Panasonic FZ55	$4,003	14	0	$56,046	$0	$17,979	$0
55	SFF Desktop	$1,251	3	0	$3,752	$0	$1,204	$0
56	SFF Desktop	$1,385	0	10	$0	$13,851	$0	$4,204
57	Surface Pro Tablets	$2,008	2	0	$4,015	$0	$1,288	$0
58	Surface Pro Tablets	$1,942	0	5	$0	$9,712	$0	$2,948
59	Teams Monitors	$324	92	0	$29,841	$0	$9,573	$0
60	Teams Monitors	$323	0	145	$0	$46,879	$0	$14,228
61	Accessories				$181,343	$78,504	$58,175	$23,826
62	Shipping and Handling/other fees				$12,942	$8,765	$4,152	$2,660
63	Software, labor, contractor and overhead and other costs				$312,824	$273,429	$100,354	$82,986
64	**Total Gas Allocation**				$6,152,454	$5,916,948	**$1,973,707**	**$1,795,794**

EXHIBIT A-23 (SHB-8)
IS CONFIDENTIAL AND
BEING FILED UNDER SEAL
WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis
Information Technology
For Years 2019 Through 2026
($0)

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Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
				Projected Capital								Projected O&M							
	Year	Case No.	Source	2019*	2020	2021	2022	2023	2024**	2025	2026	2019*	2020	2021	2022	2023	2024**	2025	2026
1	2019 Total Projected	U-18424	A-74 (CJV-3)	1,075,352								0							
2	2020 Total Projected	U-20322	A-117 (CJV-3)		1,012,288								234,802						
3	2021 Total Projected	U-20650	U20650-SA-CE-187, A-133 (CJV-4)			1,215,972								343,730					
4	2022 Total Projected	U-21148	A-131 (DDP-7), A-42 (ALC-2)				2,573,691								791,669				
5	2023 Total Projected	U-21308	A-21 (SHB-6), A-43 (ALC-2)					2,089,909								979,509			
6	2024 Total Projected	U-21490	A-20 (SHB-5), A-27 (BSB-2)						3,377,225								1,854,211		
7	2025 Total Projected	U-21806	A-20 (SHB-5)							5,726,574								1,759,591	
8	2026 Total Projected	U-21806	A-20 (SHB-5)								5,264,654								1,804,795
				Actual/Projected Capital								Actual/Projected O&M							
	Project Name	Case No.	Source	2019*	2020	2021	2022	2023	2024**	2025	2026	2019*	2020	2021	2022	2023*	2024**	2025	
9	2019 Total Actuals*	U-20650	A-133 (CJV-4)	1,220,230								573,662							
10	2020 Total Actuals	U-21148	A-131 (DDP-7), A-42 (ALC-2)		1,639,364								441,296						
11	2021 Total Actuals	U-21308	A-21 (SHB-6), A-43 (ALC-2)			2,228,324								1,130,289					
12	2022 Total Actuals	U-21490	A-20 (SHB-5), A-27 (BSB-2)				4,479,916								2,007,714				
13	2023 Total Actuals	U-21806	A-20 (SHB-5)					2,562,217								1,246,327			
14	2024 Total Projected**	U-21806	A-20 (SHB-5)						2,700,613								1,550,148		
15	Projected to Actual Variance			144,878	627,076	1,012,352	1,906,225	472,308	(676,613)			573,662	206,494	786,560	1,216,045	266,818	(304,062)		

*2019 actuals based on 6 months of actuals and 6 months of forecast data, as detailed actuals were not provided in a filing to reference.
**2024 projected based on 7 months of actuals and 5 months of forecast data

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Versus Actual Enhancement Capital Expenditures and O&M Expense Summary and Analysis
Information Technology
For Years 2019 Through 2026
($0)

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Line No.	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Actuals/Projected (Capital and O&M)						Projected (Capital and O&M)		
			2019	2020	2021	2022	2023	2024 Projected	2025 Projected	2026 Projected	Test Year
1	Total Gas Projected (Requested) Spend		$ 1,075,352	$ 1,247,089	$ 1,559,702	$ 3,365,360	$ 3,069,418	$ 5,231,436	$ 7,486,165	$ 7,069,450	$ 7,416,712
2	Total Gas Actual/Projected Spend		$ 1,793,892	$ 2,080,660	$ 3,358,613	$ 6,487,630	$ 3,808,544	$ 4,250,761	$ 7,486,165	$ 7,069,450	$ 7,416,712
3	Total Company Incremental Annual Worklist	**	$ 89,651	$ 164,509	$ 901,016	$ 2,675,947	$ 4,457,056	$ 16,068,091	$ (267,339)	$ 125,424	$ (201,879)
4	Total Gas Allocation Incremental Annual Worklist	***	$ 27,541	$ 48,826	$ 267,422	$ 803,052	$ 1,429,824	$ 4,876,666	$ (84,025)	$ 39,421	$ (63,451)
5	Total Gas Annual Demand		$ 1,821,433	$ 2,129,486	$ 3,626,035	$ 7,290,682	$ 5,238,368	$ 9,127,427	$ 7,218,826	$ 7,194,873	$ 7,214,834
6	Total Company Cumulative Worklist		$ 89,651	$ 254,161	$ 1,155,177	$ 3,831,124	$ 8,288,180	$ 24,356,271	$ 24,088,932	$ 24,214,355	$ 24,109,836
7	Total Gas Allocation Cumulative Worklist (Demand)	***	$ 27,541	$ 75,435	$ 342,856	$ 1,149,720	$ 2,658,848	$ 7,392,128	$ 7,571,151	$ 7,610,572	$ 7,577,721

**2025 and 2026 projected Total Incremental Annual Worklist based on 3-year average of Total Annual Demand (actual spend plus incremental planned worklist) less projected spend
***Estimated Gas Allocation

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Enhancement Worklist Detail
Information Technology
For Years 2016 Through October 21, 2024
($0)

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Open Date	Number	Type	Description	State	Portfolio	Configuration Item	Requestor Department	Total Estimated Hours	Planned Cost
1	1/30/2016	DMND0003200	Enhancement	RM00176542 SAP SD configuration update	Qualified	IT I&AO	SAP CCS BACK OFFICE	Cx&T-IT-TS&M-App Platforms	40	3,177
2	2/1/2016	DMND0003801	Enhancement	Ticket for labor to install a VC system purchased in 2015 for Parnall East	Qualified	Electric & Gas Combined	VIDEO CONFERENCING	Cx&T-IT-IP&S-Digital Ops- IT Constructio	-	9,096
3	2/11/2016	DMND0009972	Enhancement	Install and host the Quality Training Database (QTD) application on CE ser	Screening	Electric	Quality Training Database - QTD	ED GM-System Operations Support	-	-
4	2/15/2016	DMND0010621	Enhancement	RM00095683 Email Notifications for Landlord Portal	Qualified	IT CE&O	LLP	CX&T-Product Experience & Perf	412	32,721
5	3/7/2016	DMND0017568	Enhancement	EDI controls reports are needed	Qualified	Customer	SAP CCS BACK OFFICE	Accounts Payable & Receivable	151	11,992
6	4/4/2016	DMND0025080	Enhancement	OOB Invoices need mailed	Approved	Customer	SAP CCS BACK OFFICE	NON-ENERGY BILLING	94	-
7	6/2/2016	DMND0033513	Enhancement	Feature Add	Qualified	IT I&AO	ServiceNow	CX&T-Security-Network Security	23	1,633
8	6/27/2016	DMND0035603	Enhancement	Correct OOB Invoice Issues	Qualified	Customer	SAP CCS BACK OFFICE	BILLING CNTLS & INTERCOMPANY BILLING	158	12,548
9	7/26/2016	DMND0038277	Enhancement	Delete incorrect/never used mailing addresses in SAP	Qualified	IT CE&O	SAP CCS FRONT OFFICE	Mktg Intel-Mktg Analytics	1,500	119,130
10	10/5/2016	DMND0045344	Enhancement	Allow CRM 7 Alert to Look for Independent Phone Number	Qualified	IT CE&O	CRM7	Rates & Reg-Compliance	183	14,534
11	1/20/2017	DMND0053207	Enhancement	Updates to Non-Compliance area needed	Qualified	IT I&AO	ServiceNow	Cx&T-IT-E&GS-PlanningScheduling&MeterTec	35	2,503
12	5/9/2017	DMND0059073	Enhancement	Automate Test Evidence for SOX compliance in ServiceNow Change Tickets	Screening	IT I&AO	ServiceNow	CX&T-IT-Service Now	-	-
13	6/6/2017	DMND0060183	Enhancement	Block old rates from being used	Qualified	IT CE&O	SAP CCS BACK OFFICE	REVENUE & FUEL ACCOUNTING	104	8,260
14	6/12/2017	DMND0060511	Enhancement	Archive event logs to Event Management archive.	Qualified	IT I&AO	ServiceNow	Cx&T-IT-IP&S-Collaboration & Comms	68	5,401
15	7/26/2017	DMND0062416	Enhancement	Update Closure Rules due to Reschedules	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	64	5,083
16	9/29/2017	DMND0065531	Enhancement	ServiceNow Change: Add Vendor to QA Tester Selection	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	22	1,747
17	10/6/2017	DMND0066076	Enhancement	Add Change Coordinator & Affected CI to Reminder Notification	Qualified	App Platforms & Services	ServiceNow	CX&T-IT-Service Now	22	1,747
18	10/11/2017	DMND0066369	Enhancement	Defects in TMD Creation Tool	Qualified	IT OPS	SAP PM	Lean - Elec Distribution	192	15,249
19	11/9/2017	DMND0067863	Enhancement	Additional Message to protect Inc tied to Chg from being downgraded	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	22	1,548
20	1/12/2018	DMND0070837	Enhancement	Non-Compliance calculations incorrect	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	35	2,780
21	2/6/2018	DMND0072549	Enhancement	Corporate Compliance SharePoint Site	Qualified	Corporate	SharePoint Administration	Ethics and Compliance	-	-
22	5/2/2018	DMND0078158	Enhancement	Create Notification For Code Promotion Task Activities	Qualified	IT I&AO	ServiceNow	Cx&T-IT-S&G-ASDO	20	1,588
23	5/24/2018	DMND0079420	Enhancement	Revert to OOB for Templates	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	210	16,678
24	7/9/2018	DMND0081337	enhancement	ITAM needs to produce a automated reporting mechanism that tracks SCCM inactive users from the 30 and 60 day SCCM report.	Submitted	Corporate	SCCM Client Center	CX&T-IT-S&G-Asset Management	-	-
25	8/7/2018	DMND0083079	Enhancement	ignore seconds in implementation window failure calculation	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	28	2,224
26	8/17/2018	DMND0083607	Enhancement	Notify Change Coordinator and Technical Manageri Change Tickets	Qualified	IT I&AO	ServiceNow	Cx&T-IT-S&G-ASDO	22	1,747
27	9/6/2018	DMND0084573	Enhancement	Suppress code promotion/implementation task for non-PROD	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	56	4,448
28	11/14/2018	DMND0088854	Enhancement	Improvements to WeCare Form	Qualified	IT CE&O	Consumers Web Site	CX&T Customer Care	201	15,963
29	12/4/2018	DMND0091325	Enhancement	Internal Correspondence - Deceased; auto fill Interaction Records	Qualified	IT CE&O	SAP CCS FRONT OFFICE	DCO RO-Bankruptcy & Loss	126	10,007
30	1/2/2019	DMND0094966	Enhancement	Tech Val NonCompliance not allowing removal	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	33	2,621
31	1/8/2019	DMND0095213	Enhancement	Don't Require Outage if Parent Change Covers It	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	25	1,775
32	1/11/2019	DMND0095787	enhancement	AccessNOW Request Request	Submitted		AccessNow	Cx&T-IT-S&G-ASDO	-	-
33	1/22/2019	DMND0096689	enhancement	RPA - Automation of Forecasting Template loads to SAP	Submitted		SAP ERP FINANCE	BP&A-DSS Master Data COE	-	-
34	2/5/2019	DMND0098054	Enhancement	Price Automation Tool Enhancement	Qualified	IT CE&O	SAP CCS RATES	Rates & Reg-Rate Administration	171	13,581
35	2/14/2019	DMND0098936	Enhancement	Automation, via an RPA, the steps to get off of BOS	Screening	Customer	SAP CCS FRONT OFFICE	CX&T-IT-Contact Center and Digital Ops	-	-
36	2/21/2019	DMND0099581	Enhancement	Need extended field on an Asset Record called Order Reference Number	Qualified	Governance	ServiceNow	CX&T-IT-IP&S-IT Device Purch & Deploy	52	4,130
37	4/16/2019	DMND0104131	enhancement	Activate Business Process Monitoring KPIs in Solution Manager	Submitted		SAP SolMan - BASIS	Cx&T-IT-S&G-ASDO	-	-
38	4/22/2019	DMND0104479	Enhancement	Remove Technical Validation Complete Button once clicked	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	22	1,747
39	4/22/2019	DMND0104481	enhancement	Export MS Outlook Contacts With an Additional Field (UserId)	Submitted		Outlook	Property Accounting Reporting	-	-
40	5/1/2019	DMND0105248	Enhancement	Create a tool to test the Storm Dashboard that simulates users	Qualified	Electric	Storm Dashboard	Elec GIS LVD Operations	123	9,769
41	5/16/2019	DMND0106408	Enhancement	Add Planned Start/End to CTASK notifications and resend on reschedule	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	25	1,986
42	5/16/2019	DMND0106410	Enhancement	Lock down Contingency Dates field in Change Form	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	14	1,112
43	5/16/2019	DMND0106415	Enhancement	Install Attunity - Replicate on SAP E2S 150	Screening	IT ACDC	SAP ECS	CX&T-IT-Data & Analytics-Platforms	32	2,541
44	6/11/2019	DMND0107862	enhancement	We need to populate the Office field in Asset list from assigned to user.	Submitted		ServiceNow	Cx&T-IT-TS&M-Data Networks Operations	-	-
45	7/9/2019	DMND0109188	Enhancement	Update The GCC Postcard	Qualified	IT TEOS	SAP CCS BACK OFFICE	GE&S/GMS-Gas Cust Choice	108	6,116
46	7/25/2019	DMND0110354	enhancement	Retire Charm old maintenance cycles /phases	Submitted		SAP ECC - BASIS	Cx&T-IT-S&G-ASDO	8	635
47	8/2/2019	DMND0110809	Enhancement	Allow user options of Type and Location for outage notifications	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	97	7,704
48	8/14/2019	DMND0111406	Enhancement	Add Category Item to Service Portal to access Calero VeraSMART	Qualified	Governance	ServiceNow	CX&T-IT-P&G-Vendor & Asset Mgmt	52	7,374
49	8/27/2019	DMND0112063	Enhancement	Need Automation to Track ESB notification failures	Qualified	IT I&AO	ServiceNow	CX&T-IT-Electric Supply & Asset Mgmnt	-	-
50	9/6/2019	DMND0112727	Enhancement	Automate part or all of the Invoice Audit process using a .NET program	Screening	Customer	SAP CCS BACK OFFICE	BILLING CNTLS & INTERCOMPANY BILLING	-	-
51	10/16/2019	DMND0115341	Enhancement	Problem Management Known error state fields.	Qualified	Governance	ServiceNow	Cx&T-IT-Digital Enablement	47	3,733
52	10/28/2019	DMND0115902	Enhancement	ServiceNow Change Form - field default/selection changes	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	66	4,879
53	10/28/2019	DMND0115905	Enhancement	ServiceNow Change: Conflict Checker Automation	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	40	2,976
54	10/30/2019	DMND0116126	Enhancement	Add 'Critical Gas Control Site' checkbox to Locations	Qualified	Governance	ServiceNow	CX&T-IT-Service Now	53	2,922
55	11/8/2019	DMND0116640	Enhancement	Remove PLanned Start End from non-PROD Code promotion tasks	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	13	956
56	11/14/2019	DMND0116902	Enhancement	Allow attachments to the mixed meter investigation orders	Screening	IT CE&O	SAP CCS BACK OFFICE	CX&T-Customer Billing Res	-	-
57	11/26/2019	DMND0117927	Enhancement	Allow Revert to Review in WIP State	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	35	2,503
58	11/26/2019	DMND0117930	Enhancement	Auto-populate & hide category field	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	19	1,331
59	12/6/2019	DMND0118554	Enhancement	PROD Code Promotion Task workflow changes	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	30	2,105
60	12/6/2019	DMND0118555	Enhancement	Change Logic on QA Code Promotion Task	Qualified	IT I&AO	ServiceNow	CX&T-IT-Service Now	24	1,741
61	12/10/2019	DMND0118770	Enhancement	Hide Implementor Field/Prevent Wrong Assignment	Qualified	IT I&AO	ServiceNow	Cx&T-IT-S&G-ASDO	14	1,023
62	12/11/2019	DMND0118800	Enhancement	Restrict Code Promotion Task Closure	Qualified	IT I&AO	ServiceNow	Cx&T-IT-S&G-ASDO	30	2,099
63	12/11/2019	DMND0118821	Enhancement	Add "Planned Start Date" of Change Ticket into RM Notifications	Qualified	IT I&AO	ServiceNow	Cx&T-IT-S&G-ASDO	18	1,296
64	12/11/2019	DMND0118822	enhancement	Disable Messaging in ChaRM	Submitted		SAP SolMan - BASIS	Cx&T-IT-S&G-ASDO	-	-
65	12/20/2019	DMND0119411	Enhancement	Bill Message Update - Previous Amount Due	Qualified	Customer	SAP CCS BACK OFFICE	Rev Ops - Energy Assistance & Payment Pr	31	997
66	2/7/2020	DMND0122639	Enhancement	Tree/Branch/Limb on line add statement if service has been damaged	Qualified	IT CE&O	SAP CCS FRONT OFFICE	CX&T SCC-VCC PMCCS	16	1,188
67	2/14/2020	DMND0123010	Enhancement	CSDD bug found where customers get <21 days due date	Qualified	Customer	SAP CCS BACK OFFICE	Accounts Payable & Receivable	214	15,067
68	2/27/2020	DMND0123665	Enhancement	Digital - Application Programming Interface Fabric	Qualified	App Platforms & Services	MemSQL Database	Cx&T-IT-Strategy & Governance	520	33,920
69	2/27/2020	DMND0123697	Enhancement	UiPath to Replace BluePrism for Unattended	Qualified	IT ACDC	UiPath	CX&T-IT-Development Foundation	270	22,584
70	3/4/2020	DMND0123989	Enhancement	How do we ensure the SHP Printers	Screening	Gas	EcoPrint-ADR-Printer_PS	Operations Software & Technology	-	-
71	3/20/2020	DMND0125045	Enhancement	Provide a Quick Link to Bill Impact Tool for all Contact Center Staff Memb	Screening	IT CE&O	Customer Portal Admin	CX&T-Quality & Data Systems	-	-
72	4/30/2020	DMND0126971	Enhancement	Upgrade Quest Password Manager to latest version	Screening	IT I&AO	Password Manager	CX&T-IT-IP&S-Automation & Virtual Sprt	1	79
73	5/21/2020	DMND0128366	enhancement	Allow Copying of Standard Change Templates between Teams	Submitted		ServiceNow	CX&T-Security-Security Infra & Delivery	-	-
74	6/8/2020	DMND0129099	Enhancement	SAP Exception - Host Inquiry Work Order Creation Failed. Functional Locati	Qualified	Electric & Gas Combined	SAP WORK ORDERS	Operations Software & Technology	360	25,948
75	6/10/2020	DMND0129408	enhancement	Service Suite Mobile app - priority customer and highlight key work orders	Submitted		Service Suite	Cx&T-IT-Work and Asset Management	-	-
76	6/23/2020	DMND0130727	Enhancement	Reconfigure Timing and Frequency of Emergency Change Closure Notifications	Qualified	IT I&AO	ServiceNow	Cx&T-IT-S&G-ASDO	17	1,284
77	7/9/2020	DMND0132134	Enhancement	Auto assign tickets Remote Desktop team based on availabilty and capacity	Qualified	Infra Platforms & Services	ServiceNow	Deskside Support Jackson	80	5,942
78	8/4/2020	DMND0133953	Enhancement	VR - Class Grouping & Assignment Rules Enhacement - Elevated access	Qualified	Infrastructure Platforms & Services	ServiceNow	Cx&T-IT-IP&S-Monitoring	52	3,851
79	8/7/2020	DMND0134229	Enhancement	Set up Azure Cloud Discovery in our Service Now tenants	Qualified	Strategy	Service Catalog	CX&T-IT-Development Foundation	40	2,630
80	10/26/2020	DMND0141119	Enhancement	Timesheet Approval and Validation	Screening	IT CE&O	UiPath	CX&T-Quality & Data Systems	-	-
81	10/26/2020	DMND0141123	Enhancement	Third Pary Notification	Screening	IT CE&O	UiPath	CX&T-Quality & Data Systems	-	-
82	10/26/2020	DMND0141218	Enhancement	Allow Non Energy Account Over Payment	Screening	IT CE&O	SAP CCS FRONT OFFICE	CX&T-Digital Operations	-	-
83	10/27/2020	DMND0141417	Enhancement	Closure Failure Calculation Causing False Non-Compliances in ServiceNow CR	Qualified	Governance	ServiceNow	CX&T-IT-S&G-ASDO	29	1,920
84	11/13/2020	DMND0143177	Enhancement	Infoblox in Azure	Screening	Infra Platforms & Services	Infoblox	CX&T-IT-Development Foundation	212	16,837
85	12/4/2020	DMND0144441	Enhancement	CatCrew Enhancements: Dispatch Whiteboard & CE Resource Availability form	Qualified	Strat & Govern	Catastrophic Crewing - CatCrew	ED GM-LVD Dispatch	177	11,941
86	12/4/2020	DMND0144489	Enhancement	SAP CM40 automation enhancement	Qualified	Electric	SAP WORK ORDERS	Cx&T-IT-Work and Asset Management	303	21,318
87	1/4/2021	DMND0145977	Enhancement	Access to work order creation for CSRs OPT/OUT/GAS/GCM/SMART/METER	Qualified	Customer	SAP CCS FRONT OFFICE	CX&T SCC-CCC Policy & Procedures	6,876	869
88	1/4/2021	DMND0146047	Enhancement	Integration of request and incident ticket workflows with Pitney Bower	Qualified	Infrastructure Platforms & Services	ServiceNow	Deskside Support Jackson	68	18,005
89	1/8/2021	DMND0146402	Enhancement	work order creation - hard stop for select orders	Qualified	IT CE&O	CRM7	CX&T SCC-CCC Policy & Procedures	1,500	10,921
90	1/14/2021	DMND0146665	enhancement	Upgrade the Dialog Direct Call Center Infrastructure/Platform	Submitted		SAP CCS BACK OFFICE	Cx&T-IT-Cust-Rates Rev Gen & Collect	-	-
91	1/22/2021	DMND0147200	enhancement	CRM work order processing - change to 911 Call Summary	Submitted		SAP CCS FRONT OFFICE	CX&T SCC-CCC Policy & Procedures	-	-
92	1/22/2021	DMND0147203	Enhancement	ServiceNow Vulnerability Response - Integration Run Monitoring and Notific	Qualified	Infrastructure Platforms & Services	ServiceNow	Cx&T-IT-IP&S-Monitoring	81	6,026
93	1/27/2021	DMND0147471	enhancement	Mass Ping Tool v2	Submitted		OMS Bulletin Board	ED GM-LVD Dispatch	-	-
94	1/27/2021	DMND0147522	enhancement	SAP Post Data Refresh - CRB Contract Accounts	Submitted		SAP CCS BACK OFFICE	Cx&T-IT-S&G-ASDO	-	-
95	1/31/2021	DMND0147677	Enhancement	SAP Post Data Refresh - Missing business roles in CRM	Screening	Governance	SAP CCS BACK OFFICE	Cx&T-IT-S&G-ASDO	-	-
96	2/12/2021	DMND0148711	enhancement	Adding Orig_Read field to Meter Reader Error Report	Submitted		SAP CCS BACK OFFICE	GE&S/GAM/SI-TIMP	-	-
97	3/10/2021	DMND0150357	enhancement	Damage Assessment Mobile App - New Functionality	Submitted		Outage Management System - OI	Lean - Elec Distribution	-	-
98	3/16/2021	DMND0150717	Enhancement	A standardized way to get the SSO integration process started with new pro	Qualified	App Platforms & Services	ServiceNow	CX&T-Security-Identity Platforms	136	8,751
99	4/7/2021	DMND0151823	enhancement	Automatic Outage Notifications	Submitted		Storm Dashboard	Lean - Elec Distribution	-	-
100	4/20/2021	DMND0152479	Enhancement	SAP to IEE Sync Send Only Current Time Slice	Qualified	IT CE&O	IEE	EO-Smart Energy Operations A	-	26,106
101	4/21/2021	DMND0152549	Enhancement	Develop new Bill Consolidator Code in SAP	Screening	IT TEOS	SAP CCS BACK OFFICE	GE&S/GMS-Gas Transport & Cust Choice	-	-
102	4/26/2021	DMND0152732	Enhancement	Create a new catalog item	Qualified	Infrastructure Platforms & Services	ServiceNow	CX&T-IT-IP&S-Automation & Virtual Sprt	41	2,605
103	4/29/2021	DMND0152957	enhancement	Rel Mgmt - Reduce SAP manual transport code inspection	Submitted		SAP Quality Management	Cx&T-IT-S&G-ASDO	-	-
104	5/10/2021	DMND0153609	Enhancement	Electric Inspections Application Enhancements	Screening	Electric	Electrical Inspection Web	Cx&T-IT-Work and Asset Management	-	144,552
105	5/13/2021	DMND0153878	Enhancement	Orders which are modified in the undated folder in service suite to not dr	Qualified	Electric & Gas Combined	SAP EAM Interface	GO-Gas Scheduling SE	745	53,739
106	5/20/2021	DMND0154463	Enhancement	Implement a Master Data intake work flow with approvals and communications	Qualified	Corporate	SAP ERP FINANCE	BP&A-DSS Master Data COE	2,079	150,170
107	6/21/2021	DMND0156801	enhancement	Implement SSO and MFT for Arcos mobile app at CE	Submitted		ARCOS	CX&T-IT-S&G-Strategy E&A	-	-
108	6/28/2021	DMND0157183	Enhancement	Improve the EMMA case routing protocol	Qualified	IT CE&O	SAP CCS BACK OFFICE	CX&T-Cust Ops Projects & Support	440	30,468
109	6/29/2021	DMND0157270	Enhancement	non-emergency changes required for order summaries in CRM	Qualified	IT CE&O	SAP CCS FRONT OFFICE	CX&T SCC-CCC Policy & Procedures	16	1,324
110	7/7/2021	DMND0157740	Enhancement	EDI invoice testing/setup for Radius Point trading partner	Screening	Customer	SAP CCS BACK OFFICE	BILLING CNTLS & INTERCOMPANY BILLING	-	-
111	7/8/2021	DMND0157907	Enhancement	Production Pipeline Job Failure Notifications	Screening	IT CE&O	SAP CCS FRONT OFFICE	CX&T-IT-CEO-Proj Mgmt	-	-
112	7/29/2021	DMND0159320	enhancement	Need Access for GIS ARCMAP for Staking Contractors at minimal a VIEW ONLY Access	Submitted		GIS	GE&S-Damage Prev East	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Enhancement Worklist Detail
Information Technology
For Years 2016 Through October 21, 2024
($0)

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Open Date	Number	Type	Description	State	Portfolio	Configuration Item	Requestor Department	Total Estimated Hours	Planned Cost
113	8/4/2021	DMND0159709	Enhancement	Rate Optimization Phase 2	Approved	Customer	SAP CCS BACK OFFICE	Rates & Reg-Rate Administration	2,394	199,551
114	8/4/2021	DMND0159710	enhancement	Cannot directly open ChaRM unless logged into SolMan	Submitted		ServiceNow	Cx&T-IT-S&G-ASDO	-	-
115	8/9/2021	DMND0160130	Enhancement	Send additional Current Occupant turn off letter every 120 days	Qualified	IT CE&O	SAP CCS FRONT OFFICE	DCO-Rev Ops-Credit Operations	136	9,464
116	8/17/2021	DMND0160575	Enhancement	VR - Build Backfill Job to correct Missing VIT Data	Qualified	Infrastructure Platforms & Services	ServiceNow	Cx&T-IT-IP&S-Monitoring	46	2,936
117	8/26/2021	DMND0161178	Enhancement	In ServiceNow Change Form, Hide Change Manager Exception from ITIL Users	Approved	Governance	ServiceNow	Cx&T-IT-S&G-ASDO	38	2,464
118	9/13/2021	DMND0162757	Enhancement	Automated Developer Environments	Approved	App Platforms & Services	Azure DevTest Labs	CX&T-IT-S&G-Strategy E&A	1,277	101,419
119	10/1/2021	DMND0164324	enhancement	Load COMET Data to Dataverse	Submitted		Microsoft Dynamics 365 COMET	CX&T-IT-Contact Center and Digital Ops	-	-
120	10/1/2021	DMND0164333	enhancement	dataverse request	Submitted		SAP	Supply Chain Systems	-	-
121	10/7/2021	DMND0164923	enhancement	Enhancement to az_restoration_predictions	Submitted		SAP BI	CXCO Customer Data Analytics	-	-
122	10/8/2021	DMND0164942	Enhancement	INC0738630 - Not displaying all the Device Location remark - DMND0143012 -	Qualified	Gas	SAP WORK ORDERS	Operations Software & Technology	-	24,000
123	10/8/2021	DMND0165038	Enhancement	Service Catalog > Hardware, Work Order field validation	Qualified	Governance	ServiceNow	CX&T-IT-S&G-Asset Management	96	6,180
124	10/13/2021	DMND0165335	enhancement	RPA: SAP cust acct note on gas incidents to track restoration start to fi	Screening		SAP WORK ORDERS	Cx&T-IT-Gas Supply & Asset Mgmnt	-	-
125	10/18/2021	DMND0165596	enhancement	Configure Okta for use with Adobe SSO	Submitted		Adobe Acrobat	CX&T-Security-Identity Orchestration	-	-
126	10/27/2021	DMND0166120	Enhancement	APIM - API Catalog Portal	Approved	App Platforms & Services	Azure APIM Development	CX&T-IT-Apps, Platforms & Services	690	52,709
127	10/28/2021	DMND0166203	Enhancement	allow field to correct the stand type left on meter orders	Qualified	Gas	Service Suite	GO-Gas Dispatch & Scheduling Support	403	24,757
128	11/8/2021	DMND0166799	enhancement	PowerApps team to build a new maturity scale & dashboard	Submitted		N/A	Ethics and Compliance Oversight	-	-
129	12/3/2021	DMND0168261	Enhancement	Loading Meter Read Test Data on External Test Environments	Screening	IT CE&O	SAP CCS BACK OFFICE	Cx&T-IT-Cust-Rates Rev Gen & Collect	-	-
130	12/8/2021	DMND0168553	Enhancement	Add two new SAP Task List & Operation transactions IA38 & IA39	Qualified	Gas	SAP WORK ORDERS	Operations Software & Technology	-	24,000
131	1/5/2022	DMND0169644	Enhancement	New hardware storage for video communications team	Qualified	IT I&AO	Juniper Network Connect Client E	CX&T-IT-CPF-P&C	-	297,715
132	1/10/2022	DMND0169926	Enhancement	FIN / FOS team would like to automate time premiums for 16 hour shift wast	Qualified	Gas	SAP EAM Interface	Operations Software & Technology	308	17,599
133	1/12/2022	DMND0170179	Enhancement	Improvements to Personas	Qualified	Gas	SAP PERSONAS GEN & RENEWAL	LUDINGTON PUMP STORAGE MAINTENANCE	84	19,000
134	1/18/2022	DMND0170456	Enhancement	Gas Bypass Phase 4	Screening	Gas	SAP WORK ORDERS	Cx&T-IT-DCO-Work Mgmt	-	-
135	1/23/2022	DMND0170762	enhancement	Add Maintenance WK Center Identifier to GIS database	Submitted		GIS	GE&S/Gas Asset Info/Gas Distribution	-	-
136	1/27/2022	DMND0171205	Enhancement	Cell Phone notification if near a TOV	Submitted		Threats Of Violence Map Layer	Electric Operations Safety	-	-
137	2/2/2022	DMND0171628	enhancement	AutoETR A/B Testing	Submitted		oms	CXCO Customer Data Analytics	-	-
138	2/22/2022	DMND0173316	enhancement	Outage cause logic and automation of cause when Hazard is associated with outage	Submitted		Outage Management System - OI	GM-Products & Reporting	-	-
139	2/22/2022	DMND0173320	enhancement	Need software to automate and track MPSC compliance requirements and rules	Submitted		SAP	Rates & Reg-Compliance	-	-
140	3/1/2022	DMND0173772	Enhancement	Streetlight Mapping Update for non-CE Lighting	Submitted		Service Suite	Electric Distribution Strategy	-	-
141	3/8/2022	DMND0174317	Enhancement	Damage Assessment App for ArcGIS Enterprise	Submitted		ArcGIS	Electric GIS	-	-
142	3/8/2022	DMND0174353	Enhancement	ConsumersEnergy.com 'Brute Force' Vulnerability	Approved	Customer	SAP CCS FRONT OFFICE	CX&T-Digital Operations	1,428	200,000
143	3/11/2022	DMND0174752	Enhancement	SAP TMD Tool Update - Will Run out of 250RM Meters by October - Required C	Screening	Gas	SAP DESIGN DOCUMENTS	WM&CD Process Perf & Tech	-	-
144	3/14/2022	DMND0174883	enhancement	Implement Net Metering Calc in SAP for C&I accounts	Submitted		SAP CCS BACK OFFICE	CX&T-Customer Billing B	-	-
145	3/14/2022	DMND0174898	enhancement	Guest Pay ACH	Submitted		SAP CCS FRONT OFFICE	CX&T-Digital Operations	-	-
146	3/16/2022	DMND0175111	Enhancement	AppCurr-Gas - SIMSWeb 2023	Approved	Gas	SIMSWeb	Technology Portfolio Management	530	26,890
147	3/17/2022	DMND0175262	enhancement	Asset Audit/Invenotry - Mobile Functionality	Submitted		ServiceNow	CX&T-IT-S&G-Asset Management	-	-
148	3/23/2022	DMND0175569	Enhancement	Removal of Green Tag Device location when Notification is Complete	Qualified	Electric	SAP NOTIFICATIONS	GO-Gas Dispatch	305	21,360
149	3/23/2022	DMND0175653	Enhancement	Automation of Change and Release Process between ServiceNow and Azure DevO	Approved	App Platforms & Services	ServiceNow - PROD	CX&T-IT-S&G-Strategy E&A	524	40,803
150	4/1/2022	DMND0176410	enhancement	Enable ChaRM Creation While Change Request is in WIP	Submitted		ServiceNow	Cx&T-IT-S&G-ASDO	-	-
151	4/4/2022	DMND0176529	enhancement	e-Bills - would like to add e-Bill personalization to SMB customers	Submitted		SAP CCS FRONT OFFICE	CX&T-Residential ET	-	-
152	4/4/2022	DMND0176532	enhancement	On-Call Schedule Process - Agent Swaps	Submitted		SAP CCS FRONT OFFICE	CX&T RP TECH	-	-
153	4/12/2022	DMND0177112	enhancement	MAOP - Remove bad system values from publication	Submitted			Technology Portfolio Management	-	-
154	4/13/2022	DMND0177253	Enhancement	GAS BYPASS UPGRADES 175/250 CHANGES	Screening	Gas	SAP WORK ORDERS	Cx&T-IT-DCO-Work Mgmt	437	28,162
155	4/14/2022	DMND0177405	enhancement	Guest Pay ACH to Use Existing Payment Source	Submitted		ESB	CX&T-Digital Operations	-	-
156	4/20/2022	DMND0177795	enhancement	MV90 Evaluation for Company IT Standards	Submitted		MV90 - Distributed	EO-Smart Energy Operations A	-	-
157	4/25/2022	DMND0178109	enhancement	Updating and long term storage of Sitecore data tables created from ASP.co	Submitted		SAP CCS FRONT OFFICE	CX&T-IT-Contact Center and Digital Ops	-	-
158	4/28/2022	DMND0178405	enhancement	Update calculations on a Sharepoint Online Site	Submitted		SharePoint	GE&S/GAM/Measurement Reliability & Engin	-	-
159	5/2/2022	DMND0178625	Enhancement	New Alert needed for new field process when an action is needed for a prem	Qualified	IT CE&O	SAP CCS FRONT OFFICE	CX&T SCC-CCC Policy & Procedures	12	845
160	5/3/2022	DMND0178662	Enhancement	For RegCfg error msgs for MR doc, implement functionality to reverse MR do	Qualified	Customer	SAP CCS BACK OFFICE	CX&T-Cust Ops Projects & Support	300	16,664
161	5/11/2022	DMND0179299	Enhancement	Changes to Electric GIS Web Viewer	Qualified	Electric	Electric GIS	Electric GIS	81	6,024
162	5/20/2022	DMND0179928	Enhancement	Data Lake for SAP/OpenText Vendor Invoice management	Approved	Corporate	SAP ERP ACCOUNTS PAYABLE	Cx&T-IT-CPF-Corporate Shared Products	420	29,982
163	5/24/2022	DMND0180044	Enhancement	Performance Manager	Approved	IT TEOS	Itron Performance Manager (IPM	Technology Portfolio Management	170	12,080
164	5/24/2022	DMND0180046	Enhancement	FDM	Approved	App Platforms & Services	FDM_CMS	Technology Portfolio Management	170	12,080
165	5/24/2022	DMND0180079	enhancement	To give non-energy customers the choice to set up their invoice electronically	Submitted		Customer facing websites	Real Estate-Proj Controls	-	-
166	5/24/2022	DMND0180102	enhancement	Business Case Development - ITVAM Tool Enhancement for IT Services Suppli	Submitted		Enlighta Govern	Cx&T-IT&S-Technology Portfolio Office	-	-
167	5/26/2022	DMND0180210	Enhancement	ArcFM Web for Electric GIS Web tracing	Qualified	Electric	Electric GIS	Electric GIS	100	9,657
168	5/27/2022	DMND0180347	enhancement	Business Case Development - IT VM Tool Enhancement for IT Hardware Suppliers	Submitted		Enlighta Govern	Cx&T-IT&S-Technology Portfolio Office	-	-
169	5/27/2022	DMND0180349	enhancement	Business Case Development - IT VM Tool Enhancement for IT Software Suppliers	Submitted		Enlighta Govern	Cx&T-IT&S-Technology Portfolio Office	-	-
170	6/2/2022	DMND0180637	Enhancement	Implement Phase 2 - SW Uninstall Process Automation	Approved	App Platforms & Services	ServiceNow	CX&T-IT-P&G-Vendor & Asset Mgmt	240	11,671
171	6/6/2022	DMND0180751	Enhancement	Power BI add-in for PowerPoint	Screening	IT CE&O	Microsoft 365 - Exchange	CXCO Customer Data Analytics	2	159
172	6/8/2022	DMND0180878	Enhancement	Expand ConsumersEnergy.com Sitecore Front-End Servers from 4 to 6	Approved	Customer	Sitecore	CX&T-Digital Operations	2,262	166,265
173	6/13/2022	DMND0181141	Enhancement	SN - Modify and Add fields to Purchase Requests	Qualified	Application Platforms & Services	ServiceNow	Supply Chain Systems	80	3,886
174	6/28/2022	DMND0181878	enhancement	Append INC# to ADO Card Title for OT	Submitted		ServiceNow	CX&T-IT-Service Now	-	-
175	7/1/2022	DMND0182147	Enhancement	ARCOS to SAP Integration For Work Schedules	Approved	Corporate	ARCOS	P&C-Employee Services	578	50,216
176	7/15/2022	DMND0182656	Enhancement	Send ALL related MissDig Ticket Information to Service Suite	Qualified	Gas	SAP WORK ORDERS	Cx&T-IT-Work and Asset Management	2,679	202,593
177	7/18/2022	DMND0182699	enhancement	Add High Bill Alert Enrollment for Gas AMI Customers	Submitted		Energy Usage Dashboard	Exp Design Utility Services	-	-
178	8/3/2022	DMND0183703	Enhancement	Add CT Ratio verification to EMITS work orders	Qualified	Gas	Service Suite	EO-Elec Meter Ops	930	56,001
179	8/8/2022	DMND0183884	Enhancement	Provide rotation indicator field on metering polyphase self-contained work	Qualified	Electric	SAP WORK ORDERS	EO-Elec Meter Ops	1,173	74,542
180	8/10/2022	DMND0183990	Enhancement	Hard Stop for premises the require an inspection	Screening	Customer	CRM7	CX&T-Customer Billing Res	-	-
181	8/11/2022	DMND0184042	Enhancement	2023: Change Sync of Ownership Attributes - Owned by and Managed by for As	Approved	App Platforms & Services	ServiceNow	Cx&T-IT-Digital Enablement	55	2,973
182	8/16/2022	DMND0184229	enhancement	add a space on the storm dashboard of accumulative outages for that day	Submitted		SAP CCS FRONT OFFICE	CX&T RP TECH	-	-
183	8/24/2022	DMND0184689	Enhancement	Change MDUS delay	Screening	Customer	SAP CCS BACK OFFICE	CX&T-Customer Billing Res	-	-
184	8/24/2022	DMND0184751	Enhancement	VR Training - Pigging and other modules	Approved	Gas	OQ Plus	CX&T-IT-Gas	324	485,075
185	8/29/2022	DMND0184943	enhancement	Service Suite missing field for CT Ratio from MITS and ITR Orders	Submitted		SAP WORK MANAGEMENT	EO-Elec Mtr Ops-Zone 7	-	-
186	8/30/2022	DMND0185080	Enhancement	2023: Implement Standard Change Catalog in ServiceNow	Qualified	App Platforms & Services	ServiceNow	Cx&T-IT-S&G-ASDO	143	6,985
187	8/31/2022	DMND0185188	Enhancement	2023: Add 3 new fields to the Asset form	Qualified	Corporate	ServiceNow	CX&T-IT-S&G-Asset Management	176	9,387
188	9/6/2022	DMND0185333	enhancement	PowerAutomate/PowerApps connector to datalake Lab	Submitted		cms_data_lake.ce.corp.com	Supply Chain Systems	-	-
189	9/6/2022	DMND0185350	enhancement	2023: Build out Phase III of IT Vendor Management in ServiceNow	Submitted		ServiceNow	Cx&T-IT&S-Technology Portfolio Office	-	-
190	9/6/2022	DMND0185351	enhancement	2023: Build out of ServiceNow for IT Vendor Management - Phase II	Submitted		ServiceNow	Cx&T-IT&S-Technology Portfolio Office	-	-
191	9/9/2022	DMND0185584	Enhancement	2023: Update Text on Software Catalog Items that are not free	Approved	App Platforms & Services	ServiceNow	Cx&T-IT-Digital Enablement	31	1,533
192	9/15/2022	DMND0185758	Enhancement	SAP table to store indirect sharing of ToV data between SAP and Endeavor	Approved	Infra Platforms & Services	SAP CCS BACK OFFICE	CX&T-IT-Contact Center and Digital Ops	146	8,129
193	9/15/2022	DMND0185773	Enhancement	Unifier to Primavera P6 Integration	Qualified	Energy Combined	Unifier	Enterprise Project Management Office	532	44,915
194	9/16/2022	DMND0185822	enhancement	Create or repurpose an unused EMO work order mat type for commissioning tests	Submitted		SAP WORK ORDERS	EO-Elec Meter Ops	-	-
195	9/19/2022	DMND0185867	Enhancement	GCCP SIMS Data Conversion	Qualified	Gas	SIMS Integration	Technology Portfolio Management	1,891	145,573
196	9/20/2022	DMND0185951	Enhancement	EFLC Automation RPA WE#15025	Approved	Electric	Blue Prism RPA	CX&T-IT-S&G-Strategy E&A	755	51,431
197	9/26/2022	DMND0186329	Enhancement	Supplemental eBill at Move Out	Qualified	Customer	SAP CCS FRONT OFFICE	CX&T-Digital Operations	171	9,573
198	9/28/2022	DMND0186510	Enhancement	PQView 4 - Version upgrade	Qualified	Energy Combined	PQView	Technology Portfolio Management	-	8,552
199	9/29/2022	DMND0186597	Enhancement	Wireless Device Batch File Transfer from VeraSmart to ServiceNow	Qualified	Corporate	ServiceNow	Cx&T-IT-IP&S-Smart Ops & Analytics	246	12,046
200	10/3/2022	DMND0186784	enhancement	Bill enhancement - credit do not pay	Submitted		SAP CCS BACK OFFICE	Rev Ops - Energy Assistance & Payment Pr	-	-
201	10/3/2022	DMND0186788	enhancement	Add New "Switched to Normal Change Process" Option in Std Change templates	Submitted		ServiceNow	Cx&T-IT-S&G-ASDO	-	-
202	10/3/2022	DMND0186796	enhancement	AUTOMATE C1 NOTIFICATION TASK ASSIGNMENT BASED OFF FUNCTIONAL LOCATION	Submitted		SAP NOTIFICATIONS	Street Lighting	-	-
203	10/11/2022	DMND0187345	enhancement	AutoETR Enhancements and A/B Testing	Submitted		Outage Management System - OI	CXCO Customer Data Analytics	-	-
204	10/17/2022	DMND0187645	Enhancement	P6 Integration using the Impress Tool	Qualified	Energy Combined	Primavera P6	Enterprise Project Management Office	577	48,356

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Enhancement Worklist Detail
Information Technology
For Years 2016 Through October 21, 2024
($0)

Line No.	(a) Open Date	(b) Number	(c) Type	(d) Description	(e) State	(f) Portfolio	(g) Configuration Item	(h) Requestor Department	(i) Total Estimated Hours	(j) Planned Cost
205	10/18/2022	DMND0187754	Enhancement	2023: Asset form updates to the "Hard drive wiped status" dropdown menu	Approved	Strat & Govern	ServiceNow	CX&T-IT-S&G-Asset Management	78	3,817
206	10/19/2022	DMND0187822	enhancement	Request access to Dataverse	Submitted		Power BI	IT-D&A Services-Data Architects	-	-
207	10/19/2022	DMND0187832	enhancement	U21224 Price Updates and Line Loss Factor Updates	Submitted		SAP CCS BACK OFFICE	Rates & Reg-Rate Administration	-	-
208	10/19/2022	DMND0187851	Enhancement	2023: IT VDI Request workflow to remove the Supply Chain T&C Review step	Approved	App Platforms & Services	ServiceNow	Cx&T-IT-S&G-ASDO	63	3,066
209	10/20/2022	DMND0187897	Enhancement	SOAR Instructional Pop Up to appear daily	Qualified	Customer	Azure AD Authentication Connec	Exp Design Utility Services	90	4,810
210	10/21/2022	DMND0187973	Enhancement	Banner on SOAR during Storms	Qualified	Customer	Azure AD Authentication Connec	Exp Design Utility Services	190	10,143
211	10/26/2022	DMND0188322	enhancement	Account Lookup Error Table	Qualified	Customer	SAP CCS FRONT OFFICE	CX&T-Digital Operations	312	17,348
212	10/26/2022	DMND0188329	enhancement	GIS / SAP Functional loc / TRS comp for HDQ assign & trans	Submitted		GISElectric	Operations Software & Technology	-	-
213	10/26/2022	DMND0188366	enhancement	Complete the build of the ADMS integrated training environment	Submitted		Outage Management System - OI	Cx&T-IT-Grid Management	-	-
214	10/27/2022	DMND0188394	enhancement	On-premise Data gateway on our Server cvmwnt2934	Submitted		SAP BI	OP-Digital Products-II	-	-
215	10/31/2022	DMND0188533	Enhancement	Contaminated/Enviro. Safety message	Qualified	Gas	SAP WORK ORDERS	GO-Gas Distribution-East-Zone-2D	796	54,133
216	11/9/2022	DMND0189160	Enhancement	Change SAP WO Business Process to allow CRTD WOs with FCMP status to be re	Qualified	Energy Combined	SAP WORK ORDERS	Operations Software & Technology	558	40,431
217	11/15/2022	DMND0189382	Enhancement	Need for real-time data to support our Storm Restoration Wait-Time Tracker (real	Qualified	Energy Combined	Power BI	OP-Product Implementation-I	-	236,882
218	11/21/2022	DMND0189719	enhancement	Creation of an Intelligent Process Agent to classify records	Submitted		Total Information Management (	Cx&T-IT-CPF-Corporate Shared Products	-	-
219	11/21/2022	DMND0189727	enhancement	Enhance Storm Dashboard to Include additional Restoration key metrics	Submitted		Storm Dashboard	Cx&T-IT-Work and Asset Management	-	-
220	11/29/2022	DMND0189941	Enhancement	Customer Photos available in SOAR Admin Panel	Qualified	Customer	Azure AD Authentication Connec	Exp Design Utility Services	59	3,159
221	12/5/2022	DMND0190151	Enhancement	Gas Site Conditions Customer Contact Management and Automation	Screening	Electric	SAP NOTIFICATIONS	Cx&T-IT-Work and Asset Management	-	-
222	12/5/2022	DMND0190166	enhancement	Enhancement to our Report 20, PowerBi Reporting	Submitted		Power BI	WM&CD Process Perf & Tech	-	-
223	12/6/2022	DMND0190287	enhancement	Voluntary Green Pricing Programs Billing Automation - LCREP Automation	Screening		SAP CCS RATES	CX&T-Cust Regulatory & Compliance	2,000	158,840
224	12/7/2022	DMND0190324	enhancement	Encrypt printer data over the network	Submitted		Pitney Bowes DocuMatch? Job D	Deskside Support Jackson	-	-
225	12/9/2022	DMND0190430	Enhancement	Decommissioning Workflow Requirements	Qualified	Corporate	ServiceNow	CX&T-IT-S&G-Asset Management	94	4,596
226	12/13/2022	DMND0190554	enhancement	Eliminate paperwork(3032) for letters and postcards under 500 pieces.	Submitted		SAP CCS BACK OFFICE	Output & Mail Processing	-	-
227	12/14/2022	DMND0190693	enhancement	Need a new Critical/Priority code added to SAP	Submitted		Business Partner Services	GM-Products & Reporting	-	-
228	1/6/2023	DMND0191301	Enhancement	Stand up ADMS Integrated Training Environment	Approved	Electric	ADMS OMS	L&D Generation & Ops Support	504	32,376
229	1/11/2023	DMND0191510	Enhancement	TIM Upgrade	Approved	Corporate	Total Information Management (	CX&T-IT-Corporate Product Family	698	50,032
230	1/11/2023	DMND0191517	Enhancement	EICP (move data-) and decommission hardware	Approved	Corporate	EICP	CX&T-IT-Corporate Product Family	283	20,240
231	1/11/2023	DMND0191525	Enhancement	UI Planner - server and database upgrade	Qualified	Corporate	UIPlanner	CX&T-IT-Corporate Product Family	-	25,745
232	1/17/2023	DMND0191755	Enhancement	VR- Bifurcate OS and Non OS vulnerbilities at Third Party Library	Approved	Corporate	ServiceNow	Cx&T-IT-IP&S-Monitoring	63	3,098
233	1/17/2023	DMND0191851	Enhancement	Electric Contractor Scheduling Personas Screen	Qualified	Energy Combined	SAP PERSONAS DISTR SCHEDULI	WM&CD Gas Planning & Resource Mgmt-CTR	281	16,126
234	1/18/2023	DMND0191905	enhancement	Need data on customer account balance	Submitted		SAP CCS BACK OFFICE	GE&S/GMS-Gas Cust Choice	-	-
235	1/23/2023	DMND0192099	Enhancement	Need Enhancements to Custom Transaction ZSCE420_PROCESS_ERR2 - Sort Error	Qualified	Energy Combined	SAP WORK MANAGEMENT	EO-Smart Energy Operations A	443	25,728
236	1/27/2023	DMND0192348	Enhancement	Share GIS Information with External Stakeholders	Approved	Electric	ArcGIS	Technology Portfolio Management	844	187,800
237	1/30/2023	DMND0192467	enhancement	Automate Monthly MIC-6 Reporting	Submitted		ServiceNow	Cx&T-IT-S&G-ASDO	-	-
238	1/30/2023	DMND0192471	enhancement	Automate/Simplify Annual Standard Change Template Recertification	Submitted		ServiceNow	Cx&T-IT-S&G-ASDO	-	-
239	2/10/2023	DMND0193379	Enhancement	Calendar that will integrate multiple different planning calendars into 1 place	Qualified	Corporate	Power BI	CX&T - Channels	-	10,594
240	2/22/2023	DMND0194019	Enhancement	Website SMB STP Enrollment	Qualified	Customer	Consumers Web Site	CX&T-Digital Operations	110	5,855
241	2/23/2023	DMND0194195	Enhancement	Would like to have Romet test files uploaded to SAP from excel or like fil	Qualified	Electric	SAP QM	EO - MTC Production and Logistics.	281	15,612
242	2/24/2023	DMND0194257	Enhancement	Upgrade EMMAX to Release 5 with Support Package 4 and configure PAM enhanc	Approved	Infra Platforms & Services	SAP CCS BACK OFFICE	CX&T-IT-Core App Platforms-SAP	200	34,096
243	2/28/2023	DMND0194460	enhancement	Updating pre-programmed customer segmentation on MPSC Gas Insert	Submitted		SAP CCS BACK OFFICE	Creative Services and Communications	-	-
244	2/28/2023	DMND0194461	enhancement	MPSC Bill Insert Waste Elimination on Second Copy Rebills	Submitted		SAP CCS BACK OFFICE	Creative Services and Communications	-	-
245	3/1/2023	DMND0194566	Enhancement	Unifier - Enhancements	Approved	Energy Combined	Unifier	Technology Portfolio Management	122	46,158
246	3/7/2023	DMND0194965	Enhancement	Sub-domain creation for Local Gov't Benchmarking pilot	Screening	Customer	IT CUST PROGRAMS - Transporta	CX&T-Product Innov Bus Pilots	-	-
247	3/8/2023	DMND0195023	Enhancement	AppCurr E&GS Unifier P6 upgrade	Approved	Energy Combined	Unifier	Technology Portfolio Management	1,211	156,877
248	3/8/2023	DMND0195103	enhancement	Form 1676 process and/or collection of 671 HPM & 676 Reg std	Submitted		SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	-
249	3/13/2023	DMND0195368	Enhancement	CONNECT PORTAL: Updates to Master Template for Provisioning Connect Sites	Qualified	Corporate	Connect	P&C-Workforce Planning & Analytics	28	2,076
250	3/20/2023	DMND0195715	Enhancement	Changes to Gas GIS Web Viewer	Qualified	Electric	GIS Web Locator and Viewer	GE&S/Gas Asset Information	63	5,824
251	3/21/2023	DMND0195825	Enhancement	ADMS - OMS Home	Approved	Electric	ADMS	Technology Portfolio Management	1,071	76,082
252	3/21/2023	DMND0195833	Enhancement	ADMS - Outage Apps (Storm Hub)	Approved	Electric	ADMS	Technology Portfolio Management	620	45,151
253	3/22/2023	DMND0195904	enhancement	Customizable Return Address for Certain Bills in SAP Batch Billing	Submitted		SAP CCS BACK OFFICE	OP-Product Implementation-II	-	-
254	3/24/2023	DMND0196012	enhancement	Auto Submission to DebtNext (180 file) once bankruptcy is removed from an accoun	Submitted		SAP CCS COLLECTIONS	CX&T-Revenue Ops & Assistance	-	-
255	3/27/2023	DMND0196096	Enhancement	OpenText - High Availability	Qualified	Infra Platforms & Services	OpenText Administration Client 1	CX&T-IT-Core App Platforms-SAP	600	108,787
256	3/27/2023	DMND0196118	Enhancement	Tibco API Exchange Gateway Replacement	Qualified	App Platforms & Services	TIBCO ESB	Cx&T-IT-Enterprise Middleware	688	67,422
257	3/29/2023	DMND0196232	enhancement	Automation/Update of ZEOEMV SAP Transaction	Submitted		SAP CCS BACK OFFICE	CX&T-Quality & Data Systems	-	-
258	3/31/2023	DMND0196360	Enhancement	Sync Issues between Endeavor and SAP	Approved	Customer	SAP CCS BACK OFFICE	CX&T-IT-Contact Center and Digital Ops	888	45,657
259	4/10/2023	DMND0196779	enhancement	Sample data from service Suite for productivity report	Submitted		Service Suite	OP-Analytics Products	-	-
260	4/14/2023	DMND0197065	Enhancement	Extract data from Power BI Service	Qualified	Customer	Power BI	CXCO Customer Data Analytics	-	6,810
261	4/14/2023	DMND0197075	enhancement	IVR - authentication design change	Submitted		Genesys IVR	CX&T-Cust Ops Projects & Support	-	-
262	4/17/2023	DMND0197131	Enhancement	Add service type variable to T973 and T783	Screening	Corporate	SAP CCS BACK OFFICE	Creative Services and Communications	-	-
263	4/17/2023	DMND0197166	Enhancement	Update to CE.Com enrollment process for ACPC and H2O DR Programs	Approved	Customer	IT CUST PROGRAMS - Demand Si	CX&T-Product Innov Bus Pilots	150	12,805
264	4/20/23	DMND0197381	Enhancement	Ebill and Outage files load testing for KUBRA upgrade	Approved	Customer	SAP CCS FRONT OFFICE	Rev Ops - Energy Assistance & Payment Pr	49	3,258
265	4/24/23	DMND0197483	Enhancement	Add the logic to ZSCR260_PCARD_TRANS to allow filtering of supervisor pern	Screening	Electric	SAP ERP FINANCE	WM&CD-SW Zone-BCK/COLD/HAS/MAR	125	9,928
266	4/24/23	DMND0197500	Enhancement	Automated process to validate results after SAP transports are imported.	Approved	App Platforms & Services	SAP	Cx&T-IT-SAP Dev Standards	1,718	57,641
267	4/26/23	DMND0197604	Enhancement	Add column to SQM survey file that is sent to SQM.	Approved	Customer	Genesys IVR	CX&T RP TECH	146	10,975
268	4/28/23	DMND0197681	Enhancement	Metadata Pull Automation	Approved	Customer	SAP CCS BACK OFFICE	Cx&T-IT-Cust-Rates Rev Gen & Collect	241	10,331
269	4/28/23	DMND0197689	Enhancement	Migrate legal files into legal file area in TIM.	Screening	Corporate	Total Information Management (	DGC-Transactions & Employment	10	794
270	5/1/23	DMND0197736	Enhancement	Updating default task list under the Make Ready priority	Screening	Electric	SAP WORK ORDERS	Network Attachments	-	-
271	5/1/23	DMND0197746	enhancement	WE# 9878: Automate adding new operation to order	Submitted		SAP WORK ORDERS	GO-Gas Scheduling SE	-	-
272	5/1/23	DMND0197747	enhancement	Microsoft 365 External Third Party Sharing Request	Submitted		Real Estate Questions	Real Estate-Proj Controls	-	-
273	5/3/23	DMND0197817	enhancement	Create standard library of Powerpoint macros	Submitted			Corporate Strategy	-	-
274	5/4/23	DMND0197839	Enhancement	DocuSign OKTA Integration	Qualified	Corporate	DocuSign for Outlook	CX&T-IT-Corporate Product Family	-	16,047
275	5/5/23	DMND0197913	Enhancement	Add more MATs for Emplifi Customer Surveys	Qualified	Customer	SAP WORK MANAGEMENT	Cx&T-Customer Research	-	7,838
276	5/8/23	DMND0197981	enhancement	Need a way to identify repeat work orders in Endeavor	Submitted		SAP CCS FRONT OFFICE	CX&T-Home & Ind Mat Logistics & Inv Mgmt	-	-
277	5/9/23	DMND0198059	Enhancement	Legal Phone Collection Forensic Tool	Qualified	Corporate	Security	Cx&T-IT-CPF-Corporate Shared Products	1,719	66,203
278	5/10/23	DMND0198102	enhancement	Create Storm Responder Program Board "Circuit Restoration Coordinator"	Submitted		ADMS	Incident Management	-	-
279	5/16/23	DMND0198375	Enhancement	Link put into every sap order even emerg	Screening	Electric	Service Suite	EO-LVD-WEST-ZONE 5-BENZIE	-	-
280	5/18/23	DMND0198585	Enhancement	Request for Gas emergency over 60 minute flag in Service Suite	Screening	Gas	Service Suite	GO-Gas Dispatch SE A	60	4,765
281	5/18/23	DMND0198589	Enhancement	Comments should post to Wage or Absence type entries from a WAT entry in FSS	Qualified	Energy Combined	SAP WORK ORDERS	Operations Software & Technology	-	19,200
282	5/19/23	DMND0198655	Enhancement	GALT REL Order/MAT Type Change Request	Qualified	Gas	SAP WORK ORDERS	GO-Gas Distribution-North-Zone-2D	-	26,474
283	5/19/23	DMND0198656	Enhancement	Limiting Access to Gas Emergency Acknowledgements	Screening	Gas	Service Suite	GO-Gas Dispatch	-	-
284	5/19/23	DMND0198657	Enhancement	Add Headquarter to Dispatch Emergency Acknowledgement pop up in Service Suite	Screening	Gas	Service Suite	GO-Gas Dispatch NE	-	-
285	5/19/23	DMND0198661	enhancement	Automate timesheet premiums via Service Suite, SS/SAP Interface or SAP HR Module	Submitted		SAP WORK ORDERS	Operations Software & Technology	-	-
286	5/19/23	DMND0198691	Enhancement	GCCP DNV Inspection Manager Changes- Leak Tracking (Vendor Work)	Approved	Gas	Inspection Manager - GCC	GE&S/GAM/SI/DIMP-Reg Mgmt & DIMP Opt.	20	5,096
287	5/26/23	DMND0199008	Enhancement	Distribution Regulation enhancement for WAM with Inspection Manager	Screening	Gas	SAP WORK ORDERS	Go-Gas Dist-Regulation-Statewide	-	-
288	5/26/23	DMND0199015	enhancement	Create a Malfunction form in Service Suite	Submitted		Service Suite	GO-Gas Service-Southeast C4	-	-
289	5/26/23	DMND0199016	enhancement	MITS phase 2: Add "inspection pass or fail" field to C&I meter completion form	Submitted		SAP WORK ORDERS	GO-Gas Service-Southeast C4	-	-
290	5/26/23	DMND0199017	Enhancement	Phase 2 MITS Automation - Update maintenance plan on exchange/replace job	Screening	Gas	SAP WORK ORDERS	GO-Gas Service-Southeast C4	-	-
291	6/1/23	DMND0199093	Enhancement	Remove measle from gas new business order/mat types	Qualified	Gas	Service Suite	Technology Portfolio Management	-	13,200
292	6/6/23	DMND0199256	Enhancement	Build a report to send email to employees for 'In Process' timesheet recor	Approved	Corporate	SAP ERP PAYROLL	Payroll & Payroll Processing	538	16,919

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Line No.	(a) Open Date	(b) Number	(c) Type	(d) Description	(e) State	(f) Portfolio	(g) Configuration Item	(h) Requestor Department	(i) Total Estimated Hours	(j) Planned Cost
293	6/6/23	DMND0199324	Enhancement	Create a workflow for new equipment requests/installs in data centers	Approved	Electric	ADMS	Technology Portfolio Management	371	29,585
294	6/7/23	DMND0199381	Enhancement	ConsumersEnergy.com Forestry Requests	Approved	Customer	Consumers Web Site	CX&T-Digital Operations	303	16,715
295	6/8/23	DMND0199424	enhancement	Disconnect/Reconnect p	Submitted		SAP CCS FRONT OFFICE	Exp Design Utility Services	-	-
296	6/13/23	DMND0199626	Enhancement	Excavators are not able to see the comments left by Gas Transmission locat	Screening	Gas	SAP WORK MANAGEMENT	OCC-Dam Prev & PSO	-	-
297	6/15/23	DMND0199804	Enhancement	Voluntary Green Pricing Programs Billing Automation - LCREP Automation	Approved	Customer	SAP CCS BACK OFFICE	Rates & Reg-Rate Administration	1,544	152,733
298	6/19/23	DMND0199896	Enhancement	ServiceNow form that would prompt CEVA to ask for printer detail	Approved	Infra Platforms & Services	ServiceNow	CX&T-IT-IP&S-IT Device Purch & Deploy	80	3,911
299	6/19/23	DMND0199900	enhancement	new 800s assigned for marketing initiatives	Submitted		Genesys IVR	CX&T SCC-CCC Policy & Procedures	-	-
300	6/23/23	DMND0200102	Enhancement	GAAP Financial Reporting Work for Controllers office	Qualified	Corporate	Power BI	CX&T-IT-Corporate Product Family	-	-
301	7/13/23	DMND0200724	Enhancement	TotSum (actual) field on SAP work order not populating	Screening	Gas	SAP WORK MANAGEMENT	GO-Gas Asset Reliability Management	-	-
302	7/20/23	DMND0201004	enhancement	Change Default Lock Reason in CRM from Assistance to Blank	Submitted		SAP CCS FRONT OFFICE	CX&T-CO Strategy Support	-	-
303	7/21/23	DMND0201061	Enhancement	LIMS - Update Citrix Procurement Request	Approved	Energy Combined	LIMS NDT	Technology Portfolio Management	38	3,060
304	7/26/23	DMND0201181	Enhancement	Current Occupant Discononection Document issues.	Qualified	Customer	SAP CCS FRONT OFFICE	DCO-Rev Ops-Credit Operations	212	13,520
305	7/26/23	DMND0201212	Enhancement	SAP Exception - Business Unit Invalid - Auto correction	Screening	Work Management	SAP WORK ORDERS	Operations Software & Technology	-	-
306	7/26/23	DMND0201213	enhancement	Gas leak orders modification needed	Submitted		SAP WORK MANAGEMENT	GO-Gas Service-Southeast A4	-	-
307	7/31/23	DMND0201309	Enhancement	Produce Detail of Estimates which ties to AMI Billable Orders Report	Qualified	Customer	SAP CCS BACK OFFICE	CX&T-Customer Billing B	102	6,155
308	7/31/23	DMND0201321	enhancement	Replace Auto Updater and Attribute Inheritance with Attribute Assistant in GIS	Submitted		SIMSWeb	GE&S/Gas Asset Info/Gas Distribution	-	-
309	8/3/23	DMND0201506	Enhancement	2023 Clarity Enhancement	Approved	Corporate	Clarity	Cx&T-IT-CPF-Corporate Shared Products	305	16,179
310	8/7/23	DMND0201585	Enhancement	ArcGIS Mobile Worker Licenses	Screening	Electric	ArcGIS	Electric GIS	-	-
311	8/7/23	DMND0201590	Enhancement	SAP/Field Service Suite changes to prevent ODR Sniff test erroneous submis	Qualified	Gas	SAP WORK MANAGEMENT	GE&S/GAM/SI/DIMP-Reg Mgmt & DIMP Opt.	-	56,962
312	8/15/23	DMND0201792	Enhancement	Notification accidental closure auto fix - Put in process when order is RWRK/RSC	Screening	Energy Combined	SAP WORK MANAGEMENT	Operations Software & Technology	-	-
313	8/16/23	DMND0201902	Enhancement	Utilize Citrix to publish applications - GIS WebViewer and CRM7	Approved	Electric	Citrix	CX&T-IT-S&G-Strategy E&A	26	2,139
314	8/22/23	DMND0202067	Enhancement	Wireless Connectivity support optimization	Approved	Energy Combined	WIRELESS	Technology Portfolio Management	55	44,924
315	8/22/23	DMND0202076	enhancement	New Query Project	Submitted		SAP CCS BACK OFFICE	IT-D&A Services-Data Architects	-	-
316	8/29/23	DMND0202414	Enhancement	LNDC order type, status profile updated	Qualified	Electric	SAP WORK MANAGEMENT	Real Estate-Proj Controls	109	7,216
317	8/30/23	DMND0202482	Enhancement	Update Workflow to eliminate daily EG32 Electric removal failures.	Screening	Work Management	SAP WORK ORDERS	EO-Smart Energy Operations A	-	-
318	8/30/23	DMND0202486	Enhancement	Power BI Extract for Server Refresh Status	Approved	Energy Combined	Business Object Client tools	OP-Agile Analytics II	130	7,295
319	8/30/23	DMND0202490	Enhancement	EMITS Improvement	Qualified	Energy Combined	SAP WORK MANAGEMENT	EO-Elec Meter Ops	-	100,000
320	8/31/23	DMND0202503	Enhancement	Create ability to log storm reason codes for Dispatch Back to Pending Acti	Qualified	Electric	SAP WORK ORDERS	EO-LVD-West	331	22,100
321	9/5/23	DMND0202571	enhancement	Police/Fire Hazard Dashboard ETA Functionality	Submitted		ADMS	Incident Management	-	-
322	9/5/23	DMND0202574	enhancement	Add a Further Action Box in the Referral Tab of the Mobile App of Service Suite	Submitted		SAP WORK MANAGEMENT	OP-Digital Products-I	-	-
323	9/5/23	DMND0202575	Enhancement	Update SAP Order Operations with "Not Needed" Option for Bore & Welding Op	Screening	Work Management	SAP WORK MANAGEMENT	WM&CD-SE Dist Sched South	-	-
324	9/5/23	DMND0202578	enhancement	Flag jobs referred back as "safety" so they are not sent out til issue is checke	Submitted		Service Suite	GO-Gas Service-Southeast C5	-	-
325	9/5/23	DMND0202579	enhancement	Waste Elimination: Remove or Reduce SAP Orders printing on the SHP in Dispatch	Submitted		SAP WORK MANAGEMENT	ED GM-LVD Dispatch-GR A	-	-
326	9/5/23	DMND0202583	enhancement	Gap was identified in CatCrewing having all of the WG and WE contact information	Submitted		Catastrophic Crewing - CatCrew	EO-Elec Meter Ops	-	-
327	9/14/23	DMND0202837	enhancement	Change "direct pay" wording on customer bills	Submitted		SAP CCS BACK OFFICE	Rev Ops - Energy Assistance & Payment Pr	-	-
328	9/21/23	DMND0203058	enhancement	Unifier - Actuals Integration with SAP	Submitted		Unifier	Technology Portfolio Management	-	-
329	9/28/23	DMND0203272	Enhancement	Smartops Work Automation	Qualified	Customer	SAP CCS BACK OFFICE	CX&T-IT-CEO-Proj Mgmt	252	7,500
330	9/28/23	DMND0203283	Enhancement	Voxai - IVR changes to emergency menus	Screening	Customer	SAP CCS FRONT OFFICE	CX&T-Cust Ops Projects & Support	-	-
331	10/3/23	DMND0203365	Enhancement	Enable supervisors ability to edit employee timesheets in MSS_ 1470	Approved	Corporate	SAP ERP PAYROLL	CX&T-IT-CPF-P&C	531	62,818
332	10/3/23	DMND0203366	Enhancement	Mobile ESS_ 1470	Approved	Corporate	SAP ERP PAYROLL	CX&T-IT-CPF-P&C	1,118	156,580
333	10/5/23	DMND0203459	Enhancement	Legal Operations would like to explore software solutions for Legal Hold	Approved	Corporate	Legal Hold Pro	DGC-Litigation Practice Area	395	24,558
334	10/9/23	DMND0203513	enhancement	Add DLOC_GAS, DLOC_ELEC and DLOC_APPL to ES66 Device Location Transaction in SAP	Submitted		SAP WORK ORDERS	Distribution Engineering Office	-	-
335	10/9/23	DMND0203515	enhancement	FSS DA Manual Sequencing	Submitted		Service Suite	GO-GCON-Resource Mgmt- D	-	-
336	10/11/23	DMND0203555	enhancement	Changes needed to tcode ZSYNC_OPERAND	Submitted		IT CUST PROGRAMS - Demand Si	CX&T-IT-CEO-Proj Mgmt	-	-
337	10/12/23	375664	Enhancement	Implement Application Control in DMZ	Submitted	Security	Security	Security	300	187,500
338	10/12/23	375667	Enhancement	Encrypt USB - Removable Device Protection	Submitted	Security	Security	Security	100	32,500
339	10/12/23	375670	Enhancement	Test MDE for Andriod and IOS	Submitted	Security	Security	Security	100	12,500
340	10/12/23	375671	Enhancement	VDP (Vulnerability Disclosure Program) Database	Submitted	Security	Security	Security	100	12,500
341	10/12/23	375676	Enhancement	MDCA Managed Apps	Approved	Security	Security	Security	60	7,500
342	10/12/23	375679	Enhancement	Run Infection Monkey	Screening	Security	Security	Security	80	10,000
343	10/12/23	375681	Enhancement	Logging in Generation	Submitted	Security	Security	Security	400	85,000
344	10/12/23	375682	Enhancement	OT Server Hardening Process review	Submitted	Security	Security	Security	100	12,500
345	10/12/23	375683	Enhancement	OT Firewall/Switch Hardening Process Review	Submitted	Security	Security	Security	100	12,500
346	10/12/23	375686	Enhancement	Consider Explicit Deny Policy for Certain Services	Submitted	Security	Security	Security	80	10,000
347	10/12/23	375687	Enhancement	CIS Control 9.2 - DNS Filtering	Submitted	Security	Security	Security	80	10,000
348	10/12/23	375688	Enhancement	CIS 9.3 - Maintain and Enforce Network Based URL Filters	Submitted	Security	Security	Security	150	18,750
349	10/12/23	375689	Enhancement	CIS 8.12 - Collect Service Provider Logs	Submitted	Security	Security	Security	100	12,500
350	10/12/23	375690	Enhancement	CIS 9.5 - Implement DMARC/DKIM/SPF	Submitted	Security	Security	Security	100	12,500
351	10/12/23	375691	Enhancement	CIS 13.5 - Manage Access Control for Remote Assets	Submitted	Security	Security	Security	120	15,000
352	10/12/23	375692	Enhancement	CIS 2.5,2.6,2.7 - Allowlist Authorized Software, Allowlist Authorized Libraries, Allowlist Authorized Scripts	Submitted	Security	Security	Security	450	306,250
353	10/12/23	375793	Enhancement	STORM - Privacy Incident Tracking (Ticket/Workflow)	Submitted	Security	Security	Security	150	18,750
354	10/12/23	375795	Enhancement	Playbook to Sever CE Internet Connectivity	Approved	Security	Security	Security	150	18,750
355	10/12/23	375800	Enhancement	Island Protocol Playbook	Submitted	Security	Security	Security	180	22,500
356	10/12/23	375801	Enhancement	Assign Frequent Clicker Training	Submitted	Security	Security	Security	120	15,000
357	10/12/23	375802	Enhancement	KPMG Source Code Finding	Submitted	Security	Security	Security	150	18,750
358	10/12/23	375803	Enhancement	New Employee Playbook (NEP) Reporting Automation	Submitted	Security	Security	Security	480	60,000
359	10/12/23	375804	Enhancement	Improve Real Phishing Statics Tracking	Submitted	Security	Security	Security	160	20,000
360	10/12/23	375808	Enhancement	Remove OT Managed Non-Regulatory Devices From the Cyber Asset Library in SigmaFlow (Add to ServiceNow)	Submitted	Security	Security	Security	480	60,000
361	10/12/23	375810	Enhancement	Automate tagging of NERC CIP documents in SigmaFlow	Submitted	Security	Security	Security	480	60,000
362	10/12/23	375811	Enhancement	Automate People data being uploaded in the People Library	Submitted	Security	Security	Security	480	60,000
363	10/12/23	375814	Enhancement	CEVA STORM Automation Intake	Submitted	Security	Security	Security	120	15,000
364	10/12/23	375815	Enhancement	After Action Reports	Submitted	Security	Security	Security	480	60,000
365	10/12/23	375816	Enhancement	Emergency Managment Business Continuity Dashboard	Submitted	Security	Security	Security	160	20,000
366	10/18/23	DMND0203700	enhancement	Gateway Creation from SharePoint Online to Microsoft SQL Server	Submitted		Microsoft Power Apps (MSPA)	GE&S/GAM/SI-TIMP	-	-
367	10/24/23	DMND0203778	Enhancement	Agent Auto Assignment Module	Qualified	Infra Platforms & Services	ServiceNow	Deskside Support Jackson	106	5,163
368	10/25/23	379739	Enhancement	GP 6.2 - HIP Feature	Submitted	Security	Security	Security	80	10,000
369	10/25/23	379760	Enhancement	Microsoft DLP Enhancements (Phase 2)	Submitted	Security	Security	Security	480	60,000
370	11/6/23	DMND0203996	enhancement	Create database table, and automate P6 Milestone data, run weekly	Submitted		Primavera P6	EPM-Proj Controls Schedule-Gas Projects	-	-
371	11/6/23	DMND0204014	Enhancement	Create ServiceNow Email Interface to log an IT-to-IT Request	Qualified	Infra Platforms & Services	ServiceNow	Cx&T-IT-IAO-Database & PCTools	68	3,340
372	11/13/23	DMND0204200	enhancement	Update to the IVR message RO6050	Submitted		SAP CCS FRONT OFFICE	Customer Strategy Performance	-	-
373	11/13/23	DMND0204218	Enhancement	Create a PowerApp to request a work order for location property.	Approved	Corporate	SAP ERP POWERPLANT - TAX	General Accounting	1,830	138,098
374	11/27/23	DMND0204378	Enhancement	Emergent Work on improving the reliability and performance of the ISIS Pla	Approved	App Platforms & Services	ISIS	CX&T-IT-Enterprise Applications	4,668	359,229
375	11/29/23	DMND0204408	Enhancement	Prevent mischarging orders on manual time entry on service suite timesheets	Screening	Gas	Service Suite	GO-Gas Service-Southeast C4	-	-
376	11/29/23	DMND0204421	Enhancement	Create a flag in SAP for marking accounts with a PPA	Qualified	Work Management	SAP CCS BACK OFFICE	EO-Elec Meter Ops	-	-
377	12/5/23	DMND0204469	Enhancement	Enhance Workflow to stop duplicate meter stand orders created.	Qualified	Gas	SAP WORK MANAGEMENT	GO-Gas Service-Southeast C4	184	12,014
378	12/5/23	DMND0204476	Enhancement	Print GU LED and GUL on one invoice	Screening	Customer	SAP CCS BACK OFFICE	Rates & Reg-Rate Administration	-	-
379	12/5/23	DMND0204484	Enhancement	No Schema Extension errors - need to generate an emma case	Screening	Customer	SAP CCS BACK OFFICE	CX&T-Customer Billing B	-	-
380	12/6/23	DMND0204515	Enhancement	2024 MPSC Rate Changes	Approved	Customer	SAP CCS BACK OFFICE	CX&T-IT-CEO-Proj Mgmt	7,492	449,811
381	12/14/23	DMND0204690	enhancement	TMD issue	Submitted		SAP CCS BACK OFFICE	EO-Smart Energy Operations B	150	11,913
382	12/19/23	DMND0204788	Enhancement	RNG Voluntary Program Billing Architecture	Approved	Customer	SAP CCS BACK OFFICE	CX&T-Residential Renewables	1,879	197,668
383	12/20/23	DMND0204797	enhancement	Environmental Work Orders to PowerBI	Submitted		eSOMS	Compliance/EMS	-	-
384	1/2/24	DMND0204862	Enhancement	AutoSol Upgrade	Qualified	GAS	AutoSol	CX&T-IT-S&G-Strategy E&A	-	-
385	1/3/24	396368	Enhancement	STORM 8 Migration	Submitted	Security	Security	Security	480	95,000
386	1/3/24	DMND0204877	Enhancement	Create a report of failures and success for ZEAM_IRTH_WORK_ITEM_UPLOAD	Screening	Gas	SAP WORK MANAGEMENT	OCC-Dam Prev & PSO	-	-
387	1/4/24	DMND0204909	enhancement	Shared Outlook or Teams Calender to share w/outside contractor	Submitted		MISSING CI	EO-Lines Const & Main South & West	-	-
388	1/8/24	DMND0204932	Enhancement	Gas Meter Set - Did you rebuild the stand	Screening	Gas	Service Suite	Cx&T-IT-Work and Asset Management	-	-
389	1/9/24	DMND0204961	Enhancement	Daily Cascade Timesheet Program for Success/Failure posting report	Screening	Gas	SAP TIMESHEET IDOCS	Cx&T-IT-Work and Asset Management	-	-

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Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Open Date	Number	Type	Description	State	Portfolio	Configuration Item	Requestor Department	Total Estimated Hours	Planned Cost
390	1/9/24	DMND0204990	enhancement	Add Battle Creek city-owned lights on SOAR map with city dpw number listed	Submitted		SAP CCS FRONT OFFICE	Exp Design Utility Services	-	-
391	1/10/24	DMND0205033	Enhancement	Fidelity Administration (Restricted Stock) moving from Equinity	Approved	Corporate	ZHRPYO_FIDELITY_DEMOG_OUT	P&C HR Information Systems	1,131	118,030
392	1/11/24	DMND0205064	enhancement	Create a new Operand in SAP for PPAs	Submitted		SAP CCS BACK OFFICE	Wholesale Settlements	-	-
393	1/11/24	DMND0205119	Enhancement	Attachments viewed in CRM7 as well as SAP Back office even prior to orders FCMP	Screening	Electric	SAP WORK MANAGEMENT	EO-Elec Mtr Ops-Zone 7	-	-
394	1/17/24	DMND0205213	enhancement	GCCP 2024 Service Leak Survey - SRVY123 AGOL & DNV Import Tool Updates	Submitted		Inspection Manager - GCC	GE&S/GAM/SI/DIMP-Reg Mgmt & DIMP Opt.	-	-
395	1/23/24	DMND0205357	enhancement	C&I - Capital changes for 2024	Submitted		SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	-
396	1/24/24	DMND0205409	Enhancement	GRIP Grant SAP & Service Suite Changes	Qualified	Gas	SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	294,182
397	2/1/24	DMND0205691	enhancement	Transition Complaints Team from Avaya phones to Genesys WDE SIP end point	Submitted		SAP CCS FRONT OFFICE	CX&T SCC-CCC Policy & Procedures	-	-
398	2/5/24	DMND0205708	Enhancement	FCS application from 4.5.3 to 4.6.2	Approved	Electric	Itron FCS	Technology Portfolio Management	1,005	67,771
399	2/5/24	DMND0205714	Enhancement	Upgrade eDNA	Approved	Gas	eDNA	Cx&T-IT-E&GS-OT-Critical Applications	87	5,472
400	2/5/24	DMND0205715	Enhancement	Upgrade Citect to latest supported version	Approved	Gas	OT AVEVA Historian	Cx&T-IT-E&GS-OT-Critical Applications	124	7,802
401	2/5/24	DMND0205730	Enhancement	Upgrade Aveva PI to 2018 SP3	Approved	Gas	PI EDH	Cx&T-IT-E&GS-OT-Critical Applications	417	26,248
402	2/6/24	DMND0205743	enhancement	PIR/PID link to be resent to accounts after MIMO	Submitted		SAP CCS FRONT OFFICE	CX&T-IT-Contact Center and Digital Ops	-	-
403	2/6/24	DMND0205745	Enhancement	2 ideas - ZEAMRMITS and Pulse Constant	Qualified	Electric	Service Suite	EO-Elec Mtr Ops-Zone 7	143	21,514
404	2/12/24	DMND0205927	Enhancement	Need to Modify CAP Report	Approved	Customer	SAP CCS BACK OFFICE	CX&T BCC-Bus Solutions	18	1,997
405	2/15/24	DMND0206010	Enhancement	Add middle initial to names within Riskonnect BC&R Application	Qualified	Corporate	ServiceNow	Emergency Mgmt & Public Safety	25	1,232
406	2/19/24	DMND0206114	Enhancement	Foglight Upgrade for 2024	Approved	App Platforms & Services	FogLight for Oracle - DBA	CX&T-IT-Core App Platforms-SAP	239	28,800
407	2/19/24	DMND0206115	Enhancement	RMAN and OEM Upgrade for 2024	Approved	App Platforms & Services	DOEMP020@prmlnx0129	CX&T-IT-Core App Platforms-SAP	218	25,920
408	2/19/24	DMND0206128	Enhancement	Implement ServiceNow - Service Graph Connector for Runzero	Qualified	Corporate	ServiceNow	CX&T-IT-S&G-Asset Management	134	6,571
409	2/20/24	DMND0206129	Enhancement	SAP Planning Plant Table Update Needed	Qualified	Gas	SAP WORK MANAGEMENT	OCC-Dam Prev & PSO	-	6,660
410	2/20/24	DMND0206148	Enhancement	Azure OpenAI Non-Prod and Prod Landscapes	Qualified	App Platforms & Services	CE-Azure-Prod	Cx&T-IT-Development Standards	1,642	96,259
411	2/20/24	DMND0206168	enhancement	Time Approval (MSS) Facelift and Performance	Submitted		SAP ESS/MSS	CX&T-IT-CPF-P&C	-	-
412	2/20/24	DMND0206171	enhancement	Time Entry (ESS) Facelift and Performance	Submitted		SAP ESS/MSS	CX&T-IT-CPF-P&C	-	-
413	2/20/24	DMND0206178	Enhancement	Update bypass completion automation for GMTR RPL and GMTR NBM orders	Screening	Gas	SAP WORK MANAGEMENT	GO-Gas Service-Southeast C4	-	-
414	2/21/24	424472	Enhancement	PAM Program Maturation: Discovery (ce.corp.com, DMZ.cms, and corp.com)	Submitted	Security	Security	Security	200	37,000
415	2/21/24	DMND0206190	Enhancement	7202 - Automating A2-s into GCon Property Restoration	Qualified	Gas	GCON Property Restoration	Cx&T-IT-Work and Asset Management	453	72,892
416	2/22/24	425504	Enhancement	Vulnerability Management Data in the Lake	Submitted	Security	Security	Security	80	10,000
417	2/26/24	DMND0206377	Enhancement	573 Enlighta Remediation	Approved	Electric	Enlighta Govern	CX&T-IT-S&G-Strategy E&A	878	53,982
418	2/26/24	DMND0206378	Enhancement	Create an application to track MISS DIG Concerned Caller requests	Screening	Gas	SAP WORK MANAGEMENT	OCC-Dam Prev & PSO	-	-
419	2/27/24	DMND0206413	Enhancement	Natural Gas Outage Tag option in SAP for CSR.	Qualified	Gas	SAP WORK MANAGEMENT	GO-Gas Service-Southwest A1	-	58,233
420	2/28/24	DMND0206484	Enhancement	Power Platform Improvements	Qualified	App Platforms & Services	Microsoft Power Apps (MSPA)	Cx&T-IT-Development Standards	-	72,365
421	2/29/24	DMND0206550	Enhancement	Mobile App General O&M (not related to capital release work)	Approved	Customer	N/A	CX&T-Digital Operations	20	40,000
422	3/1/24	DMND0206577	enhancement	FACTA Automation	Submitted		CRM7	CX&T-IS-Revenue Assurance Fraud	-	-
423	3/4/24	DMND0206616	Enhancement	Automation of CSR time sheets	Approved	Customer	Genesys Framework	CX&T-Cust Ops Projects & Support	770	35,000
424	3/6/24	DMND0206682	enhancement	CE Tools - Dimension change	Submitted		CE Tools	Technology Portfolio Management	-	-
425	3/7/24	DMND0206714	Enhancement	Add CISA KEV References to SNVR Module	Qualified	Security	ServiceNow	CX&T-Security-Security Infra & Delivery	182	8,918
426	3/8/24	DMND0206764	enhancement	Modify ZBI_TOU_REPORT parameters for monthly TOU Report performed manually curre	Submitted		SAP CCS BACK OFFICE	CX&T-Customer Billing B	-	-
427	3/8/24	DMND0206781	enhancement	Bill message needs added to the bill when an interim read is present	Submitted		SAP CCS BACK OFFICE	CX&T-Customer Billing Res	-	-
428	3/12/24	DMND0206835	enhancement	Data Needed for U-20959	Submitted		SAP CCS BACK OFFICE	CXCO Customer Data Analytics	-	-
429	3/14/24	DMND0206927	Enhancement	Oracle Java to Azul Java Migration	Approved	Infra Platforms & Services	Windows7 Java	CX&T-IT-Core App Platforms-SAP	4,928	342,433
430	3/18/24	438036	Enhancement	Beacon	Submitted	Security	Security	Security	160	35,000
431	3/18/24	DMND0206963	Enhancement	Implement New Personalization Rules	Qualified	Customer	Consumers Web Site	CX&T-Digital Operations	92	5,151
432	3/19/24	DMND0206979	enhancement	Streetlight self service - ability for customers to see status when notification created in SAP	Submitted		SAP CCS FRONT OFFICE	CX&T - Experience & Portfolio Performanc	-	-
433	3/20/24	DMND0207051	Enhancement	SNOW License Manager Decommission	Approved	Corporate	Snow License Manager	CX&T-IT-Corporate Product Family	127	8,955
434	3/21/24	DMND0207086	enhancement	Add new entities (Branch, Genesse, Lake Iris) to the consol hierarchy and SAP	Submitted		SAP ERP FINANCE	Consolidated Accounting	-	-
435	3/28/24	441115	Enhancement	CSIRT POBOX Monitoring and Ticket Generation	Submitted	Security	Security	Security	60	7,500
436	4/1/24	DMND0207280	enhancement	New brand font pushed to all employees	Submitted		Microsoft Office	Brand & Creative Services	-	-
437	4/1/24	DMND0207292	enhancement	SAP New Postcard - Undergrounding	Submitted		CRM7	Creative Services and Communications	-	-
438	4/2/24	DMND0207345	Enhancement	SAP unassigned staking orders	Qualified	Gas	SAP WORK MANAGEMENT	GE&S-Damage Prev West	160	14,940
439	4/4/24	DMND0207416	Enhancement	P6 - Data Table	Approved	Electric	Primavera P6	Technology Portfolio Management	88	5,451
440	4/5/24	DMND0207456	Enhancement	MyEnergyXpertPilot	Approved	Customer	SAP CCS BACK OFFICE	CX&T-IT-CEO-Proj Mgmt	270	16,872
441	4/5/24	DMND0207461	Enhancement	ServiceNow ITOM Health - Deploy an Automated End-to End Ops Workflow	Qualified	Corporate	ServiceNow	Cx&T-IT-IP&S-Monitoring	339	123,556
442	4/9/24	444595	Enhancement	Sensitive (medium risk) data detection in email	Submitted	Security	Security	Security	80	10,000
443	4/9/24	444598	Enhancement	Automate Bi-weekly Vendor Access Review	Submitted	Security	Security	Security	400	50,000
444	4/10/24	DMND0207592	Enhancement	Aligne Fuels - Upgrade	Approved	Electric	Fuel Management System (FMS)	Technology Portfolio Management	125	9,821
445	4/10/24	DMND0207613	Enhancement	Online W2 - Payroll Automation	Approved	Corporate	SAP ERP PAYROLL	P&C HR Information Systems	339	48,523
446	4/11/24	DMND0207624	enhancement	New SAP-Business Reporting Needs for Mandated MPSC Reporting Changes	Submitted		reporting	CXCO Customer Data Analytics	-	-
447	4/11/24	DMND0207634	Enhancement	Virtual Proctoring	Screening	Electric	Gas Operator Qualification	CX&T-IT-S&G-Strategy E&A	-	-
448	4/15/24	DMND0207724	Enhancement	App Currency - WinEst	Approved	Electric	Winest	Technology Portfolio Management	120	9,467
449	4/16/24	DMND0207727	Enhancement	App Currency - LIMS	Approved	Electric	LIMS Chemistry	Technology Portfolio Management	60	5,229
450	4/16/24	DMND0207755	Enhancement	Saviynt Integration with ServiceNow for NERC CIP Compliance	Qualified	Security	ServiceNow	CX&T-Security-Identity Orchestration	146	7,118
451	4/23/24	DMND0207901	Enhancement	Credential Check and SuccessFactor Integration	Approved	Corporate	Workforce Connect (SuccessFactc	P&C HR Technologies	51	5,365
452	4/24/24	DMND0207932	Enhancement	Mass Order Creation SAP Transaction Modification	Screening	Work Management	SAP WORK MANAGEMENT	EO-Smart Energy Operations B	-	-
453	4/25/24	DMND0207999	Enhancement	Planning Group Field, FSS Communication Loop w/ SAP	Qualified	Work Management	SAP WORK MANAGEMENT	EO-Forestry HVD/T&S Inspec&Work Plan	-	7,352
454	4/26/24	DMND0208033	Enhancement	New Integration from SAP to MarketPay	Approved	Corporate	MarketPay	P&C HR Information Systems	435	63,213
455	4/29/24	DMND0208062	Enhancement	Maintain Link Data between Service Suite and SAP Work Order	Qualified	Gas	SAP WORK ORDERS	Cx&T-IT-Work and Asset Management	-	70,109
456	4/30/24	DMND0208109	Enhancement	Gas Leak automated Order creation	Approved	Work Management	SAP WORK MANAGEMENT	OP-Software Products	2,521	176,011
457	5/2/24	DMND0208154	enhancement	Update to My Location/Searched Address marker in SOAR and Map Legend	Submitted		Azure DevOps	Exp Design Utility Services	-	-
458	5/3/24	DMND0208182	Enhancement	Workstation OS Upgrade	Approved	Infra Platforms & Services	Windows 11	CX&T-IT-IP&S-Client Productivity & Comp	415	29,113
459	5/6/24	458172	Enhancement	Validate defender app connectors and if we can enable	Screening	Security	Security	Security	20	2,500
460	5/7/24	DMND0208230	Enhancement	PowerClerk & Paymentus Integration	Qualified	Electric	SAP CCS COLLECTIONS	Distribution Agreements & Programs	532	30,863
461	5/7/24	DMND0208244	Enhancement	SAPGUI upgrade to v800 and latest patch	Approved	App Platforms & Services	SAP GUI - BASIS	CX&T-IT-Core App Platforms-SAP	1,360	107,000
462	5/10/24	DMND0208329	enhancement	Update the third party damage form that is created is FSS	Submitted		MISSING CI	GE&S-Damage Claims	-	-
463	5/13/24	1337456893	Enhancement	Landlord Portal – Entire new solution	Screening	Customer	SAP CCS BACK OFFICE	CX&T-IT-CEO-Proj Mgmt		819,500
464	5/13/24	1337456895	Enhancement	High bill/inability to pay automation	Screening	Customer	SAP CCS BACK OFFICE	CX&T-IT-CEO-Proj Mgmt		983,400
465	5/13/24	1337456905	Enhancement	Web Dashboard Redesign	Screening	Customer	SAP CCS BACK OFFICE	CX&T-IT-CEO-Proj Mgmt		819,500
466	5/13/24	1337456911	Enhancement	Low/Moderate Income Enhancements	Screening	Customer	SAP CCS BACK OFFICE	CX&T-IT-CEO-Proj Mgmt		819,500
467	5/13/24	1337252489	Enhancement	Mobile App Enhancements	Submitted	Customer	SAP CCS FRONT OFFICE-old	CX&T-Digital Operations		2,121,000
468	5/13/24	460464	Enhancement	Automation for SSO to see expiring certs	Submitted	Security	Security	Security	100	12,500
469	5/13/24	460467	Enhancement	OT ISE SigmaFlow Scanning	Approved	Security	Security	Security	120	15,000
470	5/13/24	DMND0208410	Enhancement	Make updates/changes to the Theft Form in FSS	Screening	Customer	Service Suite	CX&T-RO Credit & Collection	-	-
471	5/14/24	1337856946	Enhancement	Functional Enhancements to QTD and move it to the Cloud - Quality Training Database	Screening	Electric		Electric		366,100
472	5/14/24	1337856991	Enhancement	Functional & Config Enhancements for ADMS (e.g. DMS 10)	Screening	Electric	ADMS	Electric		409,750
473	5/14/24	1337857001	Enhancement	Enhancements to various Outage Applications	Screening	Electric	Outage Management System - OI	Electric		338,500
474	5/14/24	DMND0208425	Enhancement	Welder Qualification DB - Upgrade	Approved	Electric	Welder Qualification System (WC	Technology Portfolio Management	86	7,361
475	5/14/24	DMND0208448	Enhancement	Please assign to Power Automate Team - Custom API Connector	Qualified	Customer	SAP PERSONAS FACILITIES PANEI	Field Operations Support A	-	90,035
476	5/14/24	DMND0208459	Enhancement	Unifier - Connector from Power Apps Enhancement	Approved	Electric	Microsoft Power Apps (MSPA)	Technology Portfolio Management	92	7,958
477	5/15/24	DMND0208506	enhancement	Please create meter reading route numbers (MRUS) that do not exist in SAP	Submitted		SAP CCS BACK OFFICE	Operations Software & Technology	-	-
478	5/15/24	DMND0208523	Enhancement	eSOMs mobile rounds - Covert	Qualified	Electric	eSOMS	Covert Operations	-	9,345
479	5/17/24	DMND0208600	Enhancement	Gas Measurement enhancement - AutoSol	Approved	App Platforms & Services	AutoSol	Cx&T-IT-E&GS-PlanningScheduling&MeterTec	1,684	115,558
480	5/21/24	DMND0208689	Enhancement	Customer Picture Capture Enhancement	Screening	Gas	SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	-
481	5/21/24	463764	Enhancement	Azure Front Door conversion	Submitted	Security	Security	Security	150	18,750
482	5/22/24	1393257100	Enhancement	Enhancements for small changes and improvements to existing software to address requests needed due to changing business requirements.	Screening	Infra Platforms & Services	N/A	Cx&T-IT-IP&S-Monitoring		485,959
483	5/22/24	463781	Enhancement	Security Co-Pilot and Jamf	Submitted	Security	Security	Security	40	5,000
484	5/22/24	DMND0208739	Enhancement	CYME Upgrade Project	Approved	Electric	CYME	Electric Grid Models	556	26,392
485	5/23/24	DMND0208771	Enhancement	DevonWay - Module Updates	Approved	Electric	DevonWay	Technology Portfolio Management	1,361	78,838
486	5/28/24	DMND0208797	Enhancement	Remove the measle for bar testing from 2 new business gas order mat/types	Qualified	Gas	Service Suite	OCC-Standards Adherence & Verification	30	5,539
487	5/29/24	DMND0208820	Enhancement	GenPortal - Enhancement	Qualified	Electric	Generation Portal	Technology Portfolio Management	-	9,014
488	5/29/24	DMND0208836	Enhancement	PCI Insights Software	Screening	Electric	PowerCosts (PCI) GenTrader	Wholesale Settlements	-	-
489	6/4/24	DMND0208922	enhancement	Cost of Dataverse	Submitted		Azure Data Lake	GE&S Gas Compliance and Audit	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Enhancement Worklist Detail
Information Technology
For Years 2016 Through October 21, 2024
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Line No.	(a) Open Date	(b) Number	(c) Type	(d) Description	(e) State	(f) Portfolio	(g) Configuration Item	(h) Requestor Department	(i) Total Estimated Hours	(j) Planned Cost
490	6/6/24	DMND0208986	enhancement	Gas Opt Out Fee to be added when GCM is updated out on gas only accounts	Submitted		SAP CCS BACK OFFICE	CX&T SCC-CCC Policy & Procedures	-	-
491	6/6/24	DMND0209000	Enhancement	SCCM Application Lifecycle Management	Approved	Infra Platforms & Services	Microsoft SCCM	CX&T-IT-IP&S-Client Productivity & Comp	192	14,330
492	6/6/24	DMND0209001	Enhancement	Windows Security Tool Application Lifecycle Management	Approved	Infra Platforms & Services	Microsoft SCCM	CX&T-IT-IP&S-Client Productivity & Comp	147	10,294
493	6/7/24	473175	Enhancement	Entra ID Conditional Access - Customize continuous access evaluation	Screening	Security	Security	Security	20	2,500
494	6/7/24	473196	Enhancement	Enable - Entra ID token-protection	Screening	Security	Security	Security	20	2,500
495	6/11/24	473752	Enhancement	Automation - Palo Alto Device States + Monitoring	Submitted	Security	Security	Security	80	10,000
496	6/11/24	474059	Enhancement	Duo proxy URL	Screening	Security	Security	Security	80	10,000
497	6/12/24	DMND0209117	Enhancement	New catalog request form needed for cellular activations	Qualified	Infra Platforms & Services	ServiceNow	CX&T-IT-IP&S-IT Device Purch & Deploy	87	4,244
498	6/13/24	DMND0209126	Enhancement	App Currency - ArcMap	Approved	Electric	ArcFM	Technology Portfolio Management	54	4,432
499	6/13/24	DMND0209128	Enhancement	App Currency - ArcGIS Mobile (ESRI Field Apps)	Approved	Electric	ArcGIS Mobile	Technology Portfolio Management	205	15,681
500	6/14/24	1393357040	Enhancement	Move Redwood environments to vendor SaaS solution	Screening	App Platforms & Services	Redwood	CX&T-IT-Enterprise Applications		133,750
501	6/14/24	1393357042	Enhancement	Retire OT Datacenter Hyper-V virtualization clusters; migrate workloads to VxRail	Screening	App Platforms & Services	OT	OT Platforms		107,000
502	6/14/24	1393357080	Enhancement	Biztalk Retirement and Migration	Screening	App Platforms & Services	Biztalk	CX&T-IT-Enterprise Applications		686,940
503	6/14/24	1337257014	Enhancement	Develop parallel processes and tooling to support mutliple delivery paths for project and product delivery, inclusive of Change Management Process Redesign/Retooling for SOX delivery efforts. With the direction to have some teams in ADO and others in ServiceNOW we need extra tooling to support both paths.	Screening	Corporate	ADO	Cx&T-IT-S&G-ASDO		237,100
504	6/14/24	1337257019	Enhancement	Improve the ServiceNow Platform and capabilities such as cyber ark integration, Unified Portal, Operations Workspace and AI.	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		260,200
505	6/14/24	1337252420	Enhancement	Update the API to include Org, Middile Initial, phone	Screening	Corporate	Everbridge	Emergency Management		7,490
506	6/14/24	1337257019	Enhancement	Updates and improvements to PowerBI & Data Lake	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		10,700
507	6/14/24	1337257020	Enhancement	RunZero Service Graph Connector – One time cost of internal ServiceNow team to install: $15,000	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		15,000
508	6/14/24	1337257024	Enhancement	Go Mobile with ServiceNow modules – Utilize mobile features from ServiceNow (once our subscription is updated to do so)	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		5,000
509	6/14/24	1337257027	Enhancement	ServiceNow IT Operations Management (ITOM) Digital Employee Experience (DEX) Subscriptions and associated Agent Client Connection (ACC) implementation	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		80,250
510	6/14/24	1337357035	Enhancement	ServiceNow OTM - improve OT asset inventory data in relationship to production processes and providing services	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		80,250
511	6/14/24	1337256667	Enhancement	ServiceNow OTSM – Technology Implementation	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		333,150
512	6/14/24	1337256668	Enhancement	ServiceNow APIs for OT – APIs between ServiceNow and Vendors	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		107,000
513	6/14/24	1337256669	Enhancement	ServiceNow demands related to administrative maintenance	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		10,700
514	6/14/24	1337256669	Enhancement	ServiceNow SAM Pro and related integrations Workflow Enhancements and Automations	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		53,000
515	6/14/24	1337256670	Enhancement	Enhancements/automations for systems, integrations related to Enlighta retirement	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		10,700
516	6/14/24	1337256671	Enhancement	CAM ServiceNow Decommissioning workflow enhancement	Screening	Corporate	ServiceNow	CX&T-IT-Service Now		5,350
517	6/14/24	1337257063	Enhancement	Data model for financial data reporting, sifting and scraping current SAP, PowerPlan, etc. to populate the lake, and creation of multiple reports from the lake.	Screening	Corporate		IT Finance		459,600
518	6/14/24	1337252421	Enhancement	Ability to capture forensic phone collections accurately as required by legal requests	Screening	Corporate		IT Legal		153,200
519	6/14/24	DMND0209180	enhancement	Gas/Electric Choice rate changes is removing opt out flag	Submitted		SAP CCS BACK OFFICE	CX&T SCC-CCC Policy & Procedures	110	8,736
520	6/14/24	DMND0209181	Enhancement	ServiceNow_OT_SGCs - BCSI data	Qualified	Corporate	ServiceNow	CX&T-IT-S&G-Asset Management	177	8,636
521	6/14/24	DMND0209209	Enhancement	ServiceNow_OT_SGCs - NO BCSI data	Qualified	Corporate	ServiceNow	CX&T-IT-S&G-Asset Management	339	16,564
522	6/14/24	DMND0209210	Enhancement	Create new Priority for ESIC work order type and new C1 Notification Code.	Qualified	Corporate	SAP WORK MANAGEMENT	BP&A-Gas Opns & Engg	329	20,282
523	6/18/24	DMND0209273	Enhancement	GCCP DNV Inspection Manager Changes	Approved	Gas	Inspection Manager - GCC	GE&S/GAM/SI/DIMP-Reg Mgmt & DIMP Opt.	35	26,013
524	6/19/24	DMND0209296	Enhancement	New Consent form changes in SAP	Approved	Customer	CRM7	CX&T SCC-CCC Policy & Procedures	1,008	92,000
525	6/19/24	DMND0209280	Enhancement	Reconciling Capital Charges before Field Completing Work Order	Screening	Electric	SAP WORK ORDERS	Lean - Elec Supply & Corp	-	-
526	6/21/24	478585	Enhancement	OT Assets RSA MFA Verification	Submitted	Security	Security	Security	120	15,000
527	6/24/24	DMND0209353	enhancement	Aurora CLM - Whitelisting	Submitted		AURORA	Technology Portfolio Management	-	-
528	6/24/24	DMND0209362	Enhancement	App Currency: WECO WATT-NET	Approved	Electric	WECO WinBoard Interface	Technology Portfolio Management	123	9,122
529	6/24/24	DMND0209386	Enhancement	Automating Doc Warehouse creation and sent the URL to SPIDA	Screening	Gas	SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	-
530	6/24/24	DMND0209390	Enhancement	Sending Error log to SPIDA for the Notification creation failure	Screening	Gas	SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	-
531	6/24/24	DMND0209391	Enhancement	SPIDA-SAP: Send Notification long Text to SPIDA and Work Order Integration	Screening	Gas	SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	-
532	6/25/24	DMND0209424	Enhancement	Review Onyx ecoPitch SAAS & sensors	Approved	Electric	ONYX	Cx&T-IT-Gen Ops & Electric Work Mgmnt	114	7,893
533	6/25/24	DMND0209427	Enhancement	Changing 3 SAP V5 fields from optional to required entries in the field.	Screening	Customer	Service Suite	GE&S-Damage Claims Billing	-	-
534	6/25/24	DMND0209451	enhancement	Storm digital ad automation	Submitted		Storm Information MSPA	Brand & Creative Services	-	-
535	6/26/24	DMND0209457	Enhancement	Re-establish validation check between SAP Interface & MISS DIG EOD Reports	Screening	Gas	SAP WORK MANAGEMENT	OCC-Dam Prev & PSO	-	-
536	6/26/24	DMND0209501	Enhancement	SAP/Service Suite needs the backup LCP listed	Qualified	Gas	SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	67,473
537	6/27/24	DMND0209508	Enhancement	Radio system enhancement for Barry County	Approved	Infra Platforms & Services	800 MHz IMC	Cx&T-IT-IP&S-Wireless Connectivity	91	152,898
538	6/27/24	DMND0209511	Enhancement	SAP Field Complete Status	Screening	Work Management	SAP WORK MANAGEMENT	Lean - Elec Supply & Corp	-	-
539	6/27/24	DMND0209512	Enhancement	Radio system enhancement for Calhoun County	Approved	Infra Platforms & Services	800 MHz IMC	Cx&T-IT-IP&S-Wireless Connectivity	97	161,623
540	6/28/24	480335	Enhancement	Prevent Regular users from enumerating elevated groups	Screening	Security	Security	Security	80	10,000
541	6/28/24	DMND0209552	Enhancement	Reinstation the Standish planning plant	Screening	Gas	SAP WORK MANAGEMENT	GO-Gas Dispatch NE	-	-
542	6/28/24	DMND0209553	Enhancement	Reallocation or creation of a Planning Plant for the Caro HQ	Screening	Gas	SAP WORK MANAGEMENT	GO-Gas Dispatch NE	-	-
543	7/2/24	DMND0209613	Enhancement	New Integration from SAP to JDMS	Screening	Corporate	JDMS - Job Descriptions Made Sir	P&C HR Information Systems	-	-
544	7/8/24	DMND0209696	Enhancement	MTC New Machine (DTS-II) SAP Integration	Screening	Work Management	SAP QM	EPM-Electric T&D Project Management	-	-
545	7/9/24	DMND0209724	Enhancement	Replace WAVE/WEDB tool with PowerApp	Approved	Electric	Microsoft Power Apps (MSPA)	CX&T-IT-S&G-Strategy E&A	1,123	73,153
546	7/10/24	DMND0209732	enhancement	Create Service Objects for IH01 order create	Submitted		SAP WORK ORDERS	ED GM-LVD Dispatch-GR A	-	-
547	7/12/24	DMND0209815	Enhancement	Requiring users to provide information in Required fields	Approved	App Platforms & Services	ServiceNow	Cx&T-IT-S&G-ASDO	78	3,833
548	7/12/24	DMND0209816	Enhancement	Charm must be in "Successfully tested" or "Imported to preprod" before App	Approved	App Platforms & Services	ServiceNow	Cx&T-IT-S&G-ASDO	70	3,422
549	7/12/24	DMND0209824	Enhancement	Demand Ticket to support Uplight UDP work - Carmen Ryan IT contact	Approved	Customer	Energy Usage Dashboard	Exp Design Utility Services	247	29,477
550	7/15/24	DMND0209864	Enhancement	Add Word Order Description to 1ph 400 amp electric meter material	Screening	Electric	Service Suite	EO-Elec Mtr Ops-Zone 7	-	-
551	7/16/24	DMND0209889	Enhancement	SCCM High Availability Enhancement	Approved	Infra Platforms & Services	Microsoft SCCM	CX&T-IT-IP&S-Client Productivity & Comp	91	7,227
552	7/17/24	DMND0209900	enhancement	DPO Receipt Printers/Check Scanner Testing and Install	Submitted		PC76180	DCO RO-Direct Payment Offices-North/East	-	-
553	7/18/24	DMND0209960	Enhancement	Update CRM and order management	Approved	Customer	CRM7	CX&T SCC-CCC Policy & Procedures	766	59,947
554	7/22/24	DMND0209990	Enhancement	Cisco Field Network Director	Approved	Security	Cisco IoT Field Network Director	Technology Portfolio Management	343	21,637
555	7/22/24	DMND0209992	Enhancement	Cisco IOS	Approved	Security	Cisco Identity Services Engine	Technology Portfolio Management	288	18,164
556	7/23/24	DMND0210046	Enhancement	Update SAP order processing to allow for multiple responses within LAS/DAS	Qualified	Gas	SAP WORK MANAGEMENT	GO-Gas Service-Southeast B	-	37,369
557	7/24/24	DMND0210063	Enhancement	Set up Magnit VMS integration with ServiceNow via OOTB Spoke	Approved	Corporate	ServiceNow	P&C-Workforce Planning & Analytics	118	5,789
558	7/24/24	DMND0210071	Enhancement	Website LMI Program Enrollment	Screening	Customer	Consumers Web Site	CX&T-Digital Operations	-	-
559	7/24/24	DMND0210072	Enhancement	Renewable Program Online Enrollment	Approved	Customer	Sitecore	CX&T-Digital Operations	863	90,206
560	7/29/24	491368	Enhancement	SOX UAM 7 / 2.2 - Control Automation Improvement	Submitted	Security	Security	Security	100	12,500
561	7/29/24	DMND0210127	Enhancement	Service Suite Changes to the Lawn and Hard Surface Restoration Form	Screening	Gas	Service Suite	GO-GCON-Resource Mgmt- D	-	-
562	7/31/24	DMND0210264	Enhancement	Implement SAP integration for process currently using pen and paper.	Screening	Electric	SAP QM	EO-MTC Lifecycle Assessment	-	-
563	7/31/24	DMND0210266	enhancement	Update WattNet system.	Submitted		WattNet	EO-MTC Lifecycle Assessment	-	-
564	8/2/24	DMND0210326	Enhancement	Update in_HR_ESRV_ServiceNow_1070_Positions to include Update action	Screening	Corporate	SAP ERP HR	P&C-Workforce Planning & Analytics	-	-
565	8/5/24	DMND0210343	Enhancement	Rate Card Automation/Integration Between Clarity & Magnit	Approved	Corporate	Clarity	CX&T-IT-CPF-P&C	372	64,637
566	8/5/24	DMND0210355	enhancement	Update BP enrollment email to match mailed letter	Submitted		SAP CCS PAYMENT PLANS	Rev Ops - Energy Assistance & Payment Pr	-	-
567	8/6/24	DMND0210438	Enhancement	Implement ServiceNow Oracle Global License Advisory Services data collecti	Qualified	Corporate	ServiceNow	CX&T-IT-S&G-Asset Management	40	1,968
568	8/7/24	DMND0210441	Enhancement	Need response added to SAP for end user on failure to report a no light to OMS	Screening	Electric	SAP WORK MANAGEMENT	GM-Products & Reporting	-	-
569	8/7/24	DMND0210477	Enhancement	Upgrade Singlestore to a supported version	Approved	Infra Platforms & Services	MemSQL Database	CX&T-IT-Core App Platforms-SAP	122	8,400
570	8/8/24	DMND0210494	Enhancement	CVR - DOE Enhancements	Approved	Electric	CVR Analytics	Technology Portfolio Management	684	43,436
571	8/9/24	DMND0210523	Enhancement	new chat GPT for contact center	Approved	Customer	ServiceNow	CX&T SCC-CCC Policy & Procedures	668	132,000
572	8/12/24	DMND0210548	Enhancement	Sales Tax Exemption Process Automations	Screening	Customer	CRM7	CX&T BCC-Bus Solutions	1,400	111,188

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Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Open Date	Number	Type	Description	State	Portfolio	Configuration Item	Requestor Department	Total Estimated Hours	Planned Cost
573	8/13/24	DMND0210550	enhancement	Solar Investigate Notification from CRM UI	Submitted		SAP CCS FRONT OFFICE	Distribution Agreements & Programs	-	-
574	8/13/24	DMND0210567	Enhancement	safety banner on en route screen going away when on site.	Screening	Gas	SAP WORK MANAGEMENT	GO-Gas Distribution-East-Zone-2B	-	-
575	8/13/24	DMND0210578	enhancement	BriefCatch add-in renewal and move from standalone to Microsoft 365 Admin	Submitted		BriefCatch 2.2 for Microsoft Offic	Cx&T-IT-CPF-Corporate Shared Products	-	-
576	8/16/24	DMND0210628	Enhancement	Work Planning Dashboards for Various Stakeholders	Qualified	Gas	SAP WORK MANAGEMENT FINAI	Cx&T-IT-Work and Asset Management	1,834	198,930
577	8/18/24	DMND0210638	Enhancement	Register Update /Device Modification During Rate Transition Process	Approved	Customer	SAP CCS RATES	Cx&T-IT-Cust-Rates Rev Gen & Collect	702	74,060
578	8/19/24	DMND0210639	Enhancement	App Currency - CMM database upgrade	Approved	Electric	Synergi Gas CMM Customer Man	Technology Portfolio Management	192	13,886
579	8/19/24	DMND0210663	Enhancement	CRM move out changes	Approved	Customer	CRM7	CX&T SCC-CCC Policy & Procedures	321	18,000
580	8/23/24	DMND0210866	Enhancement	Implement ServiceNow Certificate Management - Specifically Requesting a ne	Qualified	Security	ServiceNow	CX&T-Security-Security Infra & Delivery	596	29,131
581	8/26/24	DMND0210895	Enhancement	ServiceNow team - Mass Update Template form change	Approved	Infra Platforms & Services	ServiceNow	CX&T-IT-IP&S-IT Device Purch & Deploy	81	3,958
582	8/27/24	500596	Enhancement	Exchange Relay Deployment (Replace Proofpoint SER)	Approved	Security	Security	Security	150	48,750
583	8/27/24	500601	Enhancement	Automate carrier outage notifications and workflow	Screening	Security	Security	Security	60	7,500
584	9/3/24	DMND0211018	enhancement	Establish a ServiceNow portal dedicated to Corporate Safety & Health.	Submitted		ServiceNow	Safety Systems & Data	-	-
585	9/4/24	DMND0211053	Enhancement	ServiceNow AD Group & Member Integration	Qualified	App Platforms & Services	ServiceNow	Cx&T-IT-Digital Enablement	542	26,518
586	9/4/24	DMND0211073	enhancement	Connect Microsoft Project Online Data to Power BI	Submitted		Power BI	Cx&T-IT-Gen Ops & Electric Work Mgmnt	-	-
587	9/4/24	DMND0211098	Enhancement	LIAC for CARE MB customers	Approved	Customer	SAP CCS COLLECTIONS	CX&T-RO Credit & Collection	65	4,202
588	9/5/24	DMND0211125	Enhancement	DRMS Plan B DR Season Workaround Automation	Approved	Customer	IT CUST PROGRAMS - Demand Si	CX&T-IT-CEO-Proj Mgmt	285	30,924
589	9/12/24	505392	Enhancement	CyberArk Lab Feature Parity to Production	Screening	Security	Security	Security	120	15,000
590	9/13/24	DMND0211305	Enhancement	Update Meterstand Leak Repair Pipe Info in FSS	Qualified	Gas	Service Suite	GE&S/GAM/SI-DIMP	30	6,886
591	9/13/24	506016	Enhancement	Deploy Azure workbook for mfa gaps	Screening	Security	Security	Security	20	2,500
592	9/15/24	506024	Enhancement	CyberArk intergration with Azure App Registration key	Screening	Security	Security	Security	250	31,250
593	9/15/24	506026	Enhancement	Venafi - PKI	Screening	Security	Security	Security	200	125,000
594	9/17/24	DMND0211368	Enhancement	Move Sub/Holton Circuit Holton from the Muskegon to Fremont	Qualified	Work Management	SAP WORK MANAGEMENT	Operations Software & Technology	-	96,111
595	9/18/24	508050	Enhancement	Azure Logging - Auxiliary logs + SOC Optimization	Screening	Security	Security	Security	40	5,000
596	9/18/24	DMND0211405	Enhancement	Need custom report developed to get Rehire comments.	Qualified	Corporate	SAP ERP HR	P&C-Application Development	-	18,778
597	9/19/24	508207	Enhancement	Integrate Azure Key Vault and OT Cyberark into Priv Account Seperation Process	Screening	Security	Security	Security	120	15,000
598	9/19/24	508431	Enhancement	Automation for ACE tool (ACE=Annual Compliance Evaluation)	Approved	Security	Security	Security	40	5,000
599	9/20/24	508626	Enhancement	Admin account unlock request	Screening	Security	Security	Security	80	10,000
600	9/20/24	DMND0211450	enhancement	Looking to automate apprentice information	Submitted		Microsoft Power Apps (MSPA)	Elec Opers Perf & Procedures	-	-
601	9/23/24	DMND0211495	Enhancement	Service Suite 3rd Party Damage - Condition on Arrival Required - KPMG	Qualified	Gas	Service Suite	Cx&T-IT-Work and Asset Management	-	5,047
602	9/23/24	509431	Enhancement	Quest Application Evaluation	Screening	Security	Security	Security	240	30,000
603	9/23/24	509432	Enhancement	MacOS Production VPN & iBoss	Approved	Security	Security	Security	40	5,000
604	9/23/24	509468	Enhancement	Governance of Azure	Screening	Security	Security	Security	240	30,000
605	9/23/24	509469	Enhancement	Governance of Group Policy Management	Screening	Security	Security	Security	150	18,750
606	9/23/24	509470	Enhancement	MFA Application Evaluation	Screening	Security	Security	Security	150	18,750
607	9/23/24	509471	Enhancement	SSO Application Evaluation	Screening	Security	Security	Security	160	20,000
608	9/23/24	509472	Enhancement	PKI SaaS Build	Screening	Security	Security	Security	160	20,000
609	9/23/24	509474	Enhancement	OT Domain Maturation	Screening	Security	Security	Security	160	20,000
610	9/23/24	509475	Enhancement	RSA Application Maturation	Screening	Security	Security	Security	160	20,000
611	9/23/24	509476	Enhancement	OT PAM Maturation	Screening	Security	Security	Security	160	20,000
612	9/23/24	509477	Enhancement	Identity Platform Documentation	Screening	Security	Security	Security	160	20,000
613	9/23/24	509478	Enhancement	CE QA Domain	Screening	Security	Security	Security	160	20,000
614	9/23/24	509479	Enhancement	Workflow to Transition Interns, Contractors to FTE	Screening	Security	Security	Security	160	20,000
615	9/23/24	509480	Enhancement	SAP - Rearchitect Roles	Screening	Security	Security	Security	160	20,000
616	9/23/24	509481	Enhancement	Break Glass Capabilities for Identity Platforms	Screening	Security	Security	Security	160	20,000
617	9/23/24	509488	Enhancement	Identity Platform Application Currency	Screening	Security	Security	Security	160	20,000
618	9/24/24	509707	Enhancement	OTAM SolarWinds Service Graph Connector	Screening	Security	Security	Security	160	20,000
619	9/25/24	510336	Enhancement	iBoss Filtering for Macs	Screening	Security	Security	Security	160	20,000
620	9/25/24	DMND0211590	Enhancement	ServiceNow create a notification email for device return tickets	Qualified	Infra Platforms & Services	ServiceNow	CX&T-IT-IP&S-IT Device Purch & Deploy	29	1,408
621	9/27/24	DMND0211628	Enhancement	Highlight NSCE tickets	Qualified	Corporate	ServiceNow	CX&T-IT-S&G-Risk & Controls	136	6,649
622	9/27/24	DMND0211631	Enhancement	We are looking to add a new piece to our Personas page for Gas Dispatch and Sche	Qualified	Gas	SAP PERSONAS DISTR SCHEDULI	GO-Gas Dispatch & Scheduling Support	85	12,554
623	10/1/24	DMND0211666	Enhancement	Line Sensors Serial Number with field data collection	Screening	Gas	SAP WORK MANAGEMENT	Cx&T-IT-Work and Asset Management	-	-
624	10/2/24	512355	Enhancement	Island Protocol Critical Service Isolation	Screening	Security	Security	Security	160	20,000
625	10/2/24	DMND0211683	Enhancement	Fleet - Default printer update for Jackson	Qualified	Customer	Fleet Diagnostics Applications	Field Operations Support A	39	2,297
626	10/2/24	DMND0211708	Enhancement	Changes to paper & eBill	Approved	Customer	SAP CCS BACK OFFICE	Rev Ops - Energy Assistance & Payment Pr	876	30,838
627	10/4/24	DMND0211756	enhancement	Please replace letter file with new postcard file in SAP for meter access	Submitted		SAP DESIGN DOCUMENTS	Brand & Creative Services	-	-
628	10/7/24	513759	Enhancement	Automatic Validation and Closure of Azure ARC and Sentinel ServiceNow Tickets	Screening	Security	Security	Security	160	20,000
629	10/8/24	514354	Enhancement	Implement DevOps Framework for Azure Logic Apps	Screening	Security	Security	Security	160	20,000
630	10/9/24	DMND0211846	enhancement	Create new integration from SAP to Baker Tilly (LCP Tracker)	Submitted		SAP ERP HR	CX&T-IT-CPF-P&C	-	-
631	10/9/24	514813	Enhancement	On-Call Calendar Integration	Submitted	Security	Security	Security	160	20,000
632	10/10/24	515053	Enhancement	Microsoft Premium Defender Threat Intelligence	Screening	Security	Security	Security	160	20,000
633	10/11/24	DMND0211901	Enhancement	RPA: Update Micro GADS Calculated Data	Qualified	App Platforms & Services	Microsoft Power Automate Deskt	CX&T-IT-Development Foundation	175	7,207
634	10/12/24	DMND0211905	Enhancement	Create Application Security Catalog Items	Qualified	Security	ServiceNow	CX&T-Security-Security Infra & Delivery	123	4,005
635	10/13/24	515765	Enhancement	Move Azure / o365 authentication from ADFS to Entra AD	Screening	Security	Security	Security	160	20,000
636	10/14/24	515778	Enhancement	Silverfort Implementation	Approved	Security	Security	Security	300	547,500
637	10/16/24	517942	Enhancement	ITAM - update the form for NFR process	Submitted	Security	Security	Security	160	20,000
638	10/17/24	518254	Enhancement	SquaredUp Replacement	Submitted	Security	Security	Security	160	20,000
639	10/17/24	DMND0212069	Enhancement	ZLTR Improvements	Qualified	Customer	IT CUST PROGRAMS - Transporta	CX&T-IT-CEO-Proj Mgmt	661	42,859

EXHIBIT A-26 (SHB-11)
IS CONFIDENTIAL AND
BEING FILED UNDER SEAL
WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Fleet Responsibility Costs

Case No.: U-21806
Exhibit No.: A-27 (CEB-2)
Page: 1 of 1
Witness: CEBallinger
Date: December 2024

Line No.	Categories	2016	2017	2018	2019	2020	2021	2022	2023
1	Licensing	3,750,828	359,176	2,366,665	2,378,900	2,738,753	2,840,343	3,145,786	3,192,336
2	Technician	13,517,549	14,945,880	15,741,694	17,083,824	16,878,522	18,902,790	19,788,278	19,585,618
3	Parts	6,915,581	7,797,781	9,616,863	11,150,363	10,656,308	11,649,547	14,557,200	14,755,428
4	Outside Vendor	7,969,417	8,707,404	10,312,544	12,338,445	12,809,528	12,801,491	14,875,779	14,242,537
5	Fuel	10,986,225	14,273,104	16,894,736	15,398,764	12,808,774	17,865,478	25,105,355	20,322,235
6	Support Labor	4,179,501	4,310,356	4,639,242	5,203,200	5,096,942	5,034,713	5,031,440	4,790,586
7	Support Other	1,653,792	2,248,636	3,071,977	3,125,588	3,141,164	3,480,793	4,205,239	3,174,534
8	Total Cost	48,972,893	52,642,337	62,643,722	66,679,085	64,129,991	72,575,154	86,709,077	80,063,275

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Corporation
Detailed List of Projected Gas Capital Expenditures
Fleet Services
For the Years 2023, 2024, 2025 and test year 12 months ending 10/31/2026
($000)

Case No.: U-21806
Exhibit No.: A-28 (CEB-3)
Page: 1 of 2
Witness: CEBallinger
Date: December 2024

Line No.	(a)	(b)	(c) 12 months ended 12/31/2023 Projected Spend	(d) 12 months ended 12/31/2023 Projected Unit Count	(e) 12 months ending 12/31/2024 Projected Spend*	(f) 12 months ending 12/31/2024 Projected Unit Count	(g) 12 months ending 12/31/2025 Projected Spend*	(h) 12 months ending 12/31/2025 Projected Unit Count	*Test Year* (i) 12 months ending 10/31/2026 Projected Spend*	(j) 12 months ending 10/31/2026 Projected Unit Count
1	**Fleet Vehicle Capital Replacement Plan**		*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*
	Vehicle Spec	**Description**	**9,004**	**134**	**9,687**	**127**	**9,919**	**80**	**12,923**	**96**
	07	SEDAN MID SIZE 4DR	93	2	140	3	-		-	
	22	1/2 TON PICKUP	619	7	1,057	20	467	6	432	5
	23	VAN CARGO	425	5	2,048	18	1,147	12	5,800	44
	26	1 TON PICKUP WITH SERVICE BODY SHORT CAB	178	3	347	7	291	4	-	
	27	TRUCK SVC 4WD	492	7	784	9	2,347	21	787	7
	28	3/4 TON PICKUP	527	9	517	14	255	9	705	9
	41	WELDER TRUCK	-	-	464	3	161	1	-	
	42	TRUCK SVC 1T	-	-	-	-	329	3	136	1
	44	TRUCK LINE ENC BODY W/PTO COMP	3,742	17	1,528	5	4,532	21	3,931	15
	45	MECHANIC SERVICE TRUCK	-	-	762	2	-	-	-	-
	59	STAKE RACK TRUCK	-	-	-	-	-	-	129	1
	68	WALK IN SERVICE BODY VAN LD	-	-	-	-	-	-	129	1
	85	TANDUM AXLE TRACTOR WITH FIFTH WHEEL HITCH	-	-	252	1	-	-	-	
	EQUIPMENT	EQUIPMENT	1,950	17	972	9	390	3	680	8
	TRAILERS	TRAILERS	483	14	637	13	-	-	195	5
	Lease Buyout		494	53	180	23	-	-	-	
2	**Fleet Vehicle Electrification**		*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*
	Vehicle Spec	**Description**	**-**	**-**	**-**	**-**	**240**	**6**	**-**	**-**
	22	Electric Vehicle Investment	-	-	-	-	240	6		
3	**Fleet Business Partner Funded**		*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*	*($000)*	*(units)*
	Vehicle Spec	**Description**	**130**	**3**	**23**	**1**	**-**	**-**	**-**	**-**
	07	SEDAN MID SIZE 4DR	$ 130	3	$ 23	1	$ -	-	$ -	-
	22	1/2 Ton Pickup	$ 30	1						
4	**Totals:**		**9,134**	**137**	**9,710**	**128**	**10,159**	**86**	**12,923**	**96**

**The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level.*

Line No.	(a)	(b)	(c)	(d)
1	**Project Name**	**Internal Approval**	**Has a Business Case**	**Explanation**
2	Fleet Vehicle Capital Replacement Plan	YES	NO	Internal funding approval. There is no formal business case, spending level is at historical plus inflation.
3	Fleet Vehicle Electrification	YES	NO	Internal funding approval. There is no formal business case, spending level supports the Fleet Vehicle Capital Replacement plan plus the additional cost for EV units.
4	Fleet Business Partner Funded	YES	NO	Internal funding approval. There is no formal business case but there are internal support documents for individual unit need.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Corporation
Summary of Fleet Tooling Actual & Projected Capital Expenditures
Fleet Services
For the Years 2023, 2024, 2025 and test year 12 months ending 10/31/2026
($000)

Case No.: U-21806
Exhibit No.: A-29 (CEB-4)
Page: 1 of 1
Witness: CEBallinger
Date: December 2024

Line No.	(a)	(b) 12 months ended 12/31/2023 Historical	(c) 12 months ending 12/31/2024 Projected Spend	(d) 12 months ending 12/31/2025 Projected Spend	*Test Year* (e) 12 months ending 10/31/2026 Projected Spend
1	**Fleet Tools - Garage**				
	Tool Description				
	Shop Equipment	$ 171	$ 173	$ 180	$ 181
	Shop Tools	$ 23	$ 22	$ 22	$ 24
	Diagnostic Tools	$ 48	$ 43	$ 42	$ 44
2	**Fleet Tools Totals:**	**$ 242**	**$ 238**	**$ 244**	**$ 249**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Current and Historical Credit Ratings
for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-30 (MRB-8)
Page: 1 of 1
Witness: MRBleckman
Date: December 2024

Line No.		Credit Ratings (a)	(b)	(c)	(d)	(e)	(f)
1			Standard & Poors Ratings at Year End				
2		**Current**	**2023**	**2022**	**2021**	**2020**	**2019**
3	**Consumers Energy Company**						
4	Senior Secured Debt	A	A	A	A	A	A
5	Commercial Paper	A-2	A-2	A-2	A-2	A-2	A-2
6	Senior Unsecured Debt	N/A	N/A	N/A	N/A	N/A	N/A
7	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
8	Preferred Stock	N/A	N/A	N/A	N/A	N/A	N/A
9	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
10							
11	**CMS Energy Corporation**						
12	Senior Secured Debt	N/A	N/A	N/A	N/A	N/A	N/A
13	Senior Unsecured Debt	BBB	BBB	BBB	BBB	BBB	BBB
14	Junior Subordinated Debt	BBB-	BBB-	BBB-	BBB-	BBB-	BBB-
15	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
16	Preferred Stock	BBB-	BBB-	BBB-	BBB-	N/A	N/A
17	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
18							
19							
20			Moody's Ratings at Year End				
21		**Current**	**2023**	**2022**	**2021**	**2020**	**2019**
22	**Consumers Energy Company**						
23	Senior Secured Debt	A1	A1	A1	A1	Aa3	Aa3
24	Commercial Paper	P-2	P-2	P-2	P-2	P-1	P-1
25	Senior Unsecured Debt	N/A	N/A	N/A	N/A	N/A	N/A
26	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
27	Preferred Stock	Baa1	Baa1	Baa1	Baa1	A3	A3
28	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
29							
30	**CMS Energy Corporation**						
31	Senior Secured Debt	A3	A3	A3	A3	A3	A3
32	Senior Unsecured Debt	Baa2	Baa2	Baa2	Baa2	Baa1	Baa1
33	Junior Subordinated Debt	Baa3	Baa3	Baa3	Baa3	Baa2	Baa2
34	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
35	Preferred Stock	Ba1	Ba1	Ba1	Ba1	N/A	N/A
36	Outlook	Stable	Stable	Stable	Stable	Negative	Stable
37							
38							
39			Fitch Ratings at Year End				
40		**Current**	**2023**	**2022**	**2021**	**2020**	**2019**
41	**Consumers Energy Company**						
42	Senior Secured Debt	A+	A+	A+	A+	A+	A+
43	Commercial Paper	F-2	F-2	F-2	F-2	F-2	F-2
44	Senior Unsecured Debt	A	A	A	A	A	A
45	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
46	Preferred Stock	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+
47	Outlook	Stable	Stable	Stable	Stable	Stable	Stable
48							
49	**CMS Energy Corporation**						
50	Senior Secured Debt	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+
51	Senior Unsecured Debt	BBB	BBB	BBB	BBB	BBB	BBB
52	Junior Subordinated Debt	BB+	BB+	BB+	BB+	BB+	BB+
53	Hybrid Preferred Securities	N/A	N/A	N/A	N/A	N/A	N/A
54	Preferred Stock	BB+	BB+	BB+	BB+	N/A	N/A
55	Outlook	Stable	Stable	Stable	Stable	Stable	Stable

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Recent Utility Corporate Bond Issuances

for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-31 (MRB-9)
Page: 1 of 6
Witness: MRBleckman
Date: December 2024

Line No.	(a) Issue Date	(b) Ticker	(c) Issuer	(d) Type	(e) Amt ($mm)	(f) Coupon	(g) Ratings Moody's	(h) Ratings S&P	(i) Maturity	(j) Issue Spread (bp)
1	03/07/22	SRE	San Diego Gas & Electric Company	Secured	500	3.700%	A1	A	03/15/52	+155
2	03/08/22	SRE	Southern California Gas Company	Unsecured	700	2.950%	A2	A	04/15/27	+125
3	03/08/22	AVA	Avista Corporation	Secured	400	4.000%	A3	A-	04/01/52	+175
4	03/08/22	EXC	Commonwealth Edison	Secured	300	3.150%	A1	A	03/15/32	+130
5	03/08/22	EXC	Commonwealth Edison	Secured	450	3.850%	A1	A	03/15/52	+160
6	03/09/22	PEG	Public Service Electric & Gas Company	Secured	500	3.100`%	A1	A	03/15/32	+120
7	03/10/22	EVRG	Evergy Missouri West	Secured	250	3.761%	A3	A	03/15/32	+175
8	03/11/22	NGGLN	Boston Gas Company	Unsecured	400	3.757%	Baa1	BBB+	03/16/32	+175
9	03/14/22	PSD	Puget Energy Inc	Secured	450	4.224%	Baa3	BBB-	03/15/32	+210
10	03/14/22	DUK	Duke Energy Progress	Secured	500	3.400%	Aa3	A	04/01/32	+130
11	03/14/22	DUK	Duke Energy Progress	Secured	400	4.000%	Aa3	A	04/01/52	+155
12	03/17/22	NEE	NextEra Energy Capital Holdings	Unsecured	1,100	2.940%	Baa1	BBB+	03/21/24	+100
13	03/17/22	NEE	NextEra Energy Capital Holdings	Unsecured	400	FRN	Baa1	BBB+	03/21/24	SOFR+102
14	03/17/22	SWX	Southwest Gas	Unsecured	600	4.050%	Baa1	BBB	03/15/32	+190
15	03/21/22	AEE	Union Electric	Secured	525	3.900%	A2	A	04/01/52	+135
16	03/21/22	SRE	Sempra Energy	Unsecured	750	3.300%	Baa2	BBB	04/01/25	+102
17	03/21/22	SRE	Sempra Energy	Unsecured	500	3.700%	Baa2	BBB	04/01/29	+140
18	04/04/22	OGLETH	Oglethorpe Power Corp	Secured	500	4.500%	Baa1	BBB+	04/01/47	+205
19	04/19/22	BRKHEC	Berkshire Hathaway Energy Company	Unsecured	1,000	4.600%	A3	A-	05/01/53	+163
20	04/27/22	NRUC	National Rural Utilities Cooperative Finance Corp	Secured	300	3.450%	A2	A-	06/15/25	+75
21	05/02/22	SO	Georgia Power Co	Unsecured	700	4.700%	Baa1	BBB+	05/15/32	+175
22	05/02/22	SO	Georgia Power Co	Unsecured	800	5.125%	Baa1	BBB+	05/15/52	+210
23	05/02/22	AWK	American Water Capital Corp	Unsecured	800	4.450%	Baa1	A	06/01/32	+150
24	05/02/22	XEL	Northern States Power Co/MN	Secured	500	4.500%	Aa3	A	06/01/52	+148
25	05/03/22	XEL	Xcel Energy	Unsecured	700	4.600%	Baa1	BBB+	06/01/32	+167
26	05/03/22	PCG	PG&E Wildfire Recovery Funding	Secured	540	3.594%	Aaa	AAA	6/1/2030	+60
27	05/03/22	PCG	PG&E Wildfire Recovery Funding	Secured	540	4.263%	Aaa	AAA	6/1/2036	+125
28	05/03/22	PCG	PG&E Wildfire Recovery Funding	Secured	360	4.377%	Aaa	AAA	6/1/2039	+125
29	05/03/22	PCG	PG&E Wildfire Recovery Funding	Secured	1,260	4.451%	Aaa	AAA	12/1/2047	+125
30	05/03/22	PCG	PG&E Wildfire Recovery Funding	Secured	900	4.674%	Aaa	AAA	12/1/2051	+160
31	05/05/22	SO	Southern Company	Unsecured	863	4.475%	Baa3	BBB	08/01/24	+155
32	05/05/22	SO	Southern Company	Unsecured	863	5.113%	Baa3	BBB	08/01/27	+200
33	05/10/22	VST	Vistra Operations Company	Secured	400	4.875%	Baa3	BBB-	05/13/24	+225
34	05/10/22	VST	Vistra Operations Company	Secured	1,100	5.125%	Baa3	BBB-	05/13/25	+238
35	05/10/22	DUK	Piedmont Natural Gas Company	Unsecured	400	5.050%	A3	BBB+	05/15/52	+197
36	05/10/22	XEL	Public Service Co of Colorado	Secured	300	4.100%	A1	A	06/01/32	+120
37	05/10/22	XEL	Public Service Co of Colorado	Secured	400	4.500%	A1	A	06/01/52	+145
38	05/12/22	ES	NSTAR Electric Company	Unsecured	450	4.550%	A1	A	06/01/52	+157
39	05/16/22	AEP	AEP Texas	Unsecured	500	4.700%	Baa2	A-	05/15/32	+185
40	05/16/22	AEP	AEP Texas	Unsecured	500	5.250%	Baa2	A-	05/15/52	+215
41	05/16/22	D	Virginia Electric and Power Company	Unsecured	600	3.750%	A2	BBB+	05/15/27	+98
42	05/16/22	D	Virginia Electric and Power Company	Unsecured	600	4.625%	A2	BBB+	05/15/52	+160
43	05/17/22	EXC	PECO Energy Company	Secured	350	4.600%	Aa3	A	05/15/52	+147
44	05/17/22	ONCRTX	Oncor Electric Delivery Company	Secured	400	4.150%	A2	A+	06/01/32	+122
45	05/17/22	ONCRTX	Oncor Electric Delivery Company	Secured	400	4.600%	A2	A+	06/01/52	+147
46	05/18/22	WTRG	Essential Utilities	Unsecured	500	5.300%	Baa2	A-	05/01/52	+225
47	05/18/22	EIX	Southern California Edison	Secured	300	4.200%	A3	A-	06/01/25	+140
48	05/18/22	EIX	Southern California Edison	Secured	600	4.700%	A3	A-	06/01/27	+185
49	05/18/22	EIX	Southern California Edison	Secured	350	5.450%	A3	A-	06/01/52	+240
50	05/23/22	XEL	Southwestern Public Service Co	Secured	200	5.150%	A3	A	06/01/52	+210
51	06/01/22	EXC	Baltimore Gas & Electric	Unsecured	500	4.550%	A3	A	06/01/52	+145
52	06/06/22	PCG	Pacific Gas and Electric	Secured	450	4.950%	Baa3	BBB-	06/08/25	+205
53	06/06/22	PCG	Pacific Gas and Electric	Secured	450	5.450%	Baa3	BBB-	06/15/27	+245
54	06/06/22	PCG	Pacific Gas and Electric	Secured	600	5.900%	Baa3	BBB-	06/15/32	+290
55	06/07/22	NI	NISource Inc	Unsecured	350	5.000%	Baa2	BBB+	06/15/52	+190
56	06/07/22	AEP	AEP Transmission	Unsecured	550	4.500%	A2	A-	06/15/52	+140
57	06/07/22	CNP	CenterPoint Energy Resources	Unsecured	500	4.400%	A3	BBB+	07/01/32	+145
58	06/08/22	ENELIM	Enel Finance International N.V.	Unsecured	750	4.250%	Baa1	BBB+	06/15/25	+145
59	06/08/22	ENELIM	Enel Finance International N.V.	Unsecured	750	4.625%	Baa1	BBB+	06/15/27	+165
60	06/08/22	ENELIM	Enel Finance International N.V.	Unsecured	1,000	5.000%	Baa1	BBB+	06/15/32	+215
61	06/08/22	ENELIM	Enel Finance International N.V.	Unsecured	1,000	5.500%	Baa1	BBB+	06/15/52	+240
62	06/08/22	DUK	Duke Energy Corporation	Unsecured	600	3.100%	Baa2	BBB	06/15/28	+130
63	06/08/22	DUK	Duke Energy Corporation	Unsecured	500	3.850%	Baa2	BBB	06/15/34	+175
64	06/21/22	NEE	NextEra Energy Capital Holdings	Unsecured	750	4.200%	Baa1	BBB+	06/20/24	+100
65	06/21/22	NEE	NextEra Energy Capital Holdings	Unsecured	1,000	4.450%	Baa1	BBB+	06/20/25	+110
66	06/21/22	NEE	NextEra Energy Capital Holdings	Unsecured	1,250	4.625%	Baa1	BBB+	07/15/27	+125
67	06/21/22	NEE	NextEra Energy Capital Holdings	Unsecured	1,000	5.000%	Baa1	BBB+	07/15/32	+170
68	06/22/22	ES	Eversource Energy	Unsecured	900	4.200%	Baa1	BBB+	06/27/24	+115
69	06/22/22	ES	Eversource Energy	Unsecured	600	4.600%	Baa1	BBB+	07/01/27	+140
70	07/07/22	TE	Tampa Electric	Unsecured	300	3.875%	A3	BBB+	7/12/2024	+85
71	07/07/22	TE	Tampa Electric	Unsecured	300	5.000%	A3	BBB+	7/15/2052	+180
72	07/13/22	PCG	PG&E Wildfire Recovery Funding	Secured	613	4.017%	Aaa	AAA	07/08/27	+100
73	07/13/22	PCG	PG&E Wildfire Recovery Funding	Secured	600	4.719%	Aaa	AAA	08/11/34	+170
74	07/13/22	PCG	PG&E Wildfire Recovery Funding	Secured	500	5.078%	Aaa	AAA	06/24/39	+183
75	07/13/22	PCG	PG&E Wildfire Recovery Funding	Secured	1,150	5.209%	Aaa	AAA	12/07/44	+190
76	07/13/22	PCG	PG&E Wildfire Recovery Funding	Secured	1,037	5.097%	Aaa	AAA	06/14/50	+195
77	**08/01/22**	**CMS**	**Consumers Energy**	**Secured**	**350**	**3.600%**	**A1**	**A**	**08/15/32**	**+100**
78	**08/01/22**	**CMS**	**Consumers Energy**	**Secured**	**450**	**4.200%**	**A1**	**A**	**09/01/52**	**+125**
79	08/01/22	EIX	Edison International	Unsecured	400	4.700%	Baa3	BBB-	08/15/25	+190
80	08/02/22	NEE	NextEra Energy Capital Holdings	Unsecured	1,500	4.255%	Baa1	BBB+	09/01/24	+105
81	08/02/22	NGGLN	Brooklyn Union Gas Company	Unsecured	400	4.632%	Baa2	BBB+	08/05/27	+177
82	08/02/22	NGGLN	Brooklyn Union Gas Company	Unsecured	400	4.866%	Baa2	BBB+	08/05/32	+212
83	08/03/22	DTE	DTE Energy Company	Unsecured	1,300	4.220%	Baa2	BBB	09/01/24	+113
84	08/04/22	OGS	One Gas Inc	Unsecured	300	4.250%	A3	BBB+	09/01/32	+165
85	08/08/22	DUK	Duke Energy Corporation	Unsecured	900	4.300%	Baa2	BBB	03/15/28	+142
86	08/08/22	DUK	Duke Energy Corporation	Unsecured	1,150	4.500%	Baa2	BBB	08/15/32	+177
87	08/08/22	DUK	Duke Energy Corporation	Unsecured	1,150	5.000%	Baa2	BBB	08/15/52	+202
88	08/08/22	LNT	Wisconsin Power & Light	Unsecured	600	3.950%	A3	A	09/01/32	+132
89	08/09/22	D	Dominion Energy Inc	Unsecured	400	4.350%	Baa2	BBB	08/15/32	+165
90	08/09/22	D	Dominion Energy Inc	Unsecured	600	4.850%	Baa2	BBB	08/15/52	+190
91	08/09/22	SO	Alabama Power Company	Unsecured	550	3.750%	A1	A-	09/01/27	+80
92	08/09/22	SO	Alabama Power Company	Unsecured	450	3.940%	A1	A-	09/01/32	+115
93	08/10/22	NRUC	National Rural Utilities Cooperative Finance	Unsecured	400	4.150%	A1	A-	12/15/32	+140
94	08/15/22	AEE	Ameren Illinois Company	Secured	500	3.850%	A1	A	09/01/32	+108
95	08/16/22	EXC	PECO Energy Company	Secured	425	4.375%	Aa3	A	08/15/52	+127
96	08/18/22	ETR	Entergy Louisiana LLC	Secured	500	4.750%	A2	A	09/15/52	+163
97	08/22/22	ETR	Entergy Texas Inc	Secured	325	5.000%	A3	A	09/15/52	+178
98	09/06/22	SO	Southern Company Gas	Unsecured	500	5.150%	Baa1	BBB+	09/15/32	+185
99	09/06/22	ONCRTX	Oncor Electric Delivery	Secured	700	4.550%	A2	A+	09/15/32	+123
100	09/06/22	ONCRTX	Oncor Electric Delivery	Secured	500	4.950%	A2	A+	09/15/52	+148
101										

102 FRN: Floating Rate Note
103 SOFR: Secured Overnight Financing Rate
104 MS: Mid-Swap - The average of the bid and offer swap rates for a reference maturity
105 Source: Barclays Bank

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Recent Utility Corporate Bond Issuances
for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-31 (MRB-9)
Page: 2 of 6
Witness: MRBleckman
Date: December 2024

Line No.	(a) Issue Date	(b) Ticker	(c) Issuer	(d) Type	(e) Amt ($mm)	(f) Coupon	(g) Ratings Moody's	(h) Ratings S&P	(i) Maturity	(j) Issue Spread (bp)
1	09/08/22	ITC	ITC Holdings Corporation	Unsecured	600	4.950%	Baa2	BBB+	09/22/27	+158
2	09/08/22	TVA	Tennessee Valley Authority	Unsecured	500	4.250%	Aaa	AA+	09/15/52	+100
3	09/12/22	CNP	CenterPoint Energy Houston Electric	Secured	500	4.450%	A2	A	10/01/32	+115
4	09/12/22	CNP	CenterPoint Energy Houston Electric	Secured	300	4.850%	A2	A	10/01/52	+138
5	09/12/22	ES	NSTAR Electric Company	Unsecured	400	4.950%	A1	A	09/15/52	+147
6	09/12/22	NGGLN	Niagara Mohawk Power	Unsecured	500	5.783%	Baa1	BBB+	09/16/52	+225
7	09/14/22	WEC	Wisconsin Electric Power Company	Unsecured	500	4.750%	A2	A-	09/30/32	+135
8	09/22/22	WEC	WEC Energy Group	Unsecured	500	5.000%	Baa1	BBB+	09/27/25	+90
9	09/22/22	WEC	WEC Energy Group	Unsecured	400	5.150%	Baa1	BBB+	10/01/27	+128
10	09/22/22	FE	Ohio Edison	Unsecured	300	5.500%	A3	BBB	01/15/33	+185
11	09/28/22	ATO	Atmos Energy	Unsecured	300	5.450%	A1	A-	10/15/32	+152
12	09/28/22	ATO	Atmos Energy	Unsecured	500	5.750%	A1	A-	10/15/52	+195
13	10/03/22	SO	The Southern Co	Unsecured	500	5.150%	Baa2	BBB	10/06/25	+110
14	10/03/22	SO	The Southern Co	Unsecured	500	5.700%	Baa2	BBB	10/15/32	+205
15	10/03/22	EDPPL	EDP Finance BV	Unsecured	500	6.300%	Baa3	BBB	10/11/27	+245
16	10/06/22	ENELIM	Enel Finance International NV	Unsecured	750	6.800%	Baa1	BBB+	10/14/25	+275
17	10/06/22	ENELIM	Enel Finance America LLC	Unsecured	1,000	7.100%	Baa1	BBB+	10/14/27	+325
18	10/06/22	ENELIM	Enel Finance International NV	Unsecured	1,250	7.500%	Baa1	BBB+	10/14/32	+400
19	10/06/22	ENELIM	Enel Finance International NV	Unsecured	1,000	7.750%	Baa1	BBB+	10/14/52	+440
20	10/17/22	BRKHEC	Nevada Power Company	Secured	400	5.900%	A2	A+	05/01/53	+190
21	10/20/22	NRUC	National Rural Utilities Cooperative Finance	Unsecured	500	5.450%	A2	A-	10/30/25	+85
22	10/20/22	NRUC	National Rural Utilities Cooperative Finance	Unsecured	350	5.800%	A2	A-	01/15/33	+158
23	10/31/22	AEP	American Electric Power Co Inc	Unsecured	500	5.750%	Baa2	BBB+	11/1/2027	+155
24	10/31/22	AEP	American Electric Power Co Inc	Unsecured	500	5.950%	Baa2	BBB+	11/1/2032	+195
25	11/03/22	EIX	Southern California Edison Co	Secured	750	5.950%	A3	A-	11/1/2032	+190
26	11/03/22	EIX	Southern California Edison Co	Secured	750	5.850%	A3	A-	11/1/2027	+150
27	11/04/22	PEG	Public Service Enterprise Group	Unsecured	700	5.850%	Baa2	BBB	11/15/2027	+155
28	11/04/22	PNW	Arizona Public Service Co	Unsecured	400	6.350%	A3	BBB+	12/15/2032	+220
29	11/07/22	EIX	Edison International	Unsecured	550	6.950%	Baa3	BBB-	11/15/2029	+280
30	11/07/22	WEC	Wisconsin Public Service	Unsecured	300	5.350%	A2	A-	11/10/2025	+72
31	11/07/22	SRE	Southern California Gas Co	Secured	600	6.350%	Aa3	A+	11/15/2052	+205
32	11/07/22	DUK	Duke Energy Florida	Secured	500	5.950%	A1	A	11/15/2052	+167
33	11/08/22	AES	Indianapolis Power & Light	Secured	350	5.650%	A2	A-	12/1/2032	+155
34	11/08/22	AEE	Ameren Illinois Co	Secured	350	5.900%	A1	A	12/1/2052	+163
35	11/09/22	ED	Consolidated Edison Co of New York Inc	Unsecured	700	6.150%	Baa1	A-	11/15/2052	+185
36	11/16/22	D	Dominion Energy	Unsecured	850	5.375%	Baa2	BBB	11/15/32	+175
37	11/18/22	PCG	PG&E Recovery Funding LLC	Secured	215	5.045%	Aaa	AAA	07/15/34	+105
38	11/18/22	PCG	PG&E Recovery Funding LLC	Secured	200	5.256%	Aaa	AAA	01/15/40	+135
39	11/18/22	PCG	PG&E Recovery Funding LLC	Secured	568	5.536%	Aaa	AAA	07/15/49	+140
40	11/21/22	NGGLN	New England Power Company	Unsecured	300	5.936%	A3	BBB+	11/25/52	+200
41	11/28/22	EVRG	Evergy Missouri West	Secured	300	5.150%	A3	A	12/15/2027	+130
42	11/29/22	SWX	Southwest Gas Corp	Unsecured	300	5.800%	Baa1	BBB	12/1/2027	+190
43	11/29/22	BRKHEC	PacifiCorp	Secured	1,100	5.350%	A1	A+	12/1/2053	+153
44	11/30/22	PEG	Public Service Electric and Gas Co	Secured	400	4.900%	A1	A	12/15/32	+113
45	12/05/22	DUK	Duke Energy Corporation	Unsecured	500	5.000%	Baa2	BBB	12/08/25	+88
46	12/05/22	DUK	Duke Energy Corporation	Unsecured	500	5.000%	Baa2	BBB	12/08/27	+123
47	12/07/22	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	400	4.800%	A2	A-	3/15/2028	+120
48	01/03/23	ES	Connecticut Light & Power Company	Secured	500	5.250%	A1	A+	01/15/53	+135
49	01/03/23	OGE	Oklahoma Gas & Electric	Unsecured	450	5.400%	A3	A-	01/15/33	+165
50	01/03/23	EXC	Commonwealth Edison	Secured	400	4.900%	A1	A	02/01/33	+115
51	01/03/23	EXC	Commonwealth Edison	Secured	575	5.300%	A1	A	02/01/53	+140
52	01/03/23	DUK	Duke Energy Carolinas	Secured	900	4.950%	Aa3	A	1/15/2033	+120
53	01/03/23	DUK	Duke Energy Carolinas	Secured	900	5.350%	Aa3	A	1/15/2053	+145
54	01/03/23	AEP	Public Service Co. of Oklahoma	Unsecured	475	5.250%	Baa1	A-	1/15/2033	+150
55	01/03/23	ETR	Entergy Arkansas	Secured	425	5.150%	A2	A	1/15/2033	+140
56	**01/03/23**	**CMS**	**Consumers Energy**	**Secured**	**425**	**4.650%**	**A1**	**A**	**3/1/2028**	**+75**
57	01/04/23	PCG	Pacific Gas and Electric	Secured	750	6.150%	Baa3	BBB-	1/15/2033	+250
58	01/04/23	PCG	Pacific Gas and Electric	Secured	750	6.750%	Baa3	BBB-	1/15/2053	+295
59	01/04/23	ES	Public Service New Hampshire	Secured	300	5.150%	A1	A+	1/15/2053	+133
60	01/10/23	WEC	WEC Energy Group	Unsecured	650	4.750%	Baa1	BBB+	1/9/2026	+85
61	01/10/23	WEC	WEC Energy Group	Unsecured	450	4.750%	Baa1	BBB+	1/15/2028	+113
62	02/02/23	NRUC	National Rural Utilities	Unsecured	600	4.450%	A2	A-	03/13/26	+70
63	02/02/23	NRUC	National Rural Utilities (Reopening)	Unsecured	200	4.800%	A2	A-	03/15/28	+95
64	02/02/23	NRUC	National Rural Utilities (Reopening)	Secured	300	5.800%	A1	A-	01/15/33	+123
65	02/06/23	NEE	NextEra Energy Capital Holdings	Unsecured	1,250	4.900%	Baa1	BBB+	02/28/28	+110
66	02/06/23	NEE	NextEra Energy Capital Holdings	Unsecured	600	5.000%	Baa1	BBB+	02/28/30	+125
67	02/06/23	NEE	NextEra Energy Capital Holdings	Unsecured	1,000	5.050%	Baa1	BBB+	02/28/33	+140
68	02/06/23	NEE	NextEra Energy Capital Holdings	Unsecured	1,150	5.250%	Baa1	BBB+	02/28/53	+155
69	02/06/23	SR	Spire Missouri Inc	Secured	400	4.800%	A1	A	02/15/33	+120
70	**02/13/23**	**CMS**	**Consumers Energy**	**Secured**	**700**	**4.625%**	**A1**	**A**	**05/15/33**	**+97**
71	02/13/23	FTSCN	Tucson Electric Power Co	Unsecured	375	5.500%	A3	A-	04/15/53	+175
72	02/16/23	EXC	Exelon Corp	Unsecured	1,000	5.150%	Baa2	BBB	03/15/28	+113
73	02/16/23	EXC	Exelon Corp	Unsecured	850	5.300%	Baa2	BBB	03/15/33	+145
74	02/16/23	EXC	Exelon Corp	Unsecured	650	5.600%	Baa2	BBB	03/15/53	+170
75	02/21/23	CEG	Constellation Energy Generation LLC	Unsecured	750	5.600%	Baa2	BBB	03/01/28	+143
76	02/21/23	CEG	Constellation Energy Generation LLC	Unsecured	600	5.800%	Baa2	BBB	03/01/33	+185
77	02/21/23	CNP	CenterPoint Energy Resources Corp	Unsecured	600	5.250%	A3	BBB+	03/01/28	+115
78	02/21/23	CNP	CenterPoint Energy Resources Corp	Unsecured	600	5.400%	A3	BBB+	03/01/33	+145
79	02/21/23	ED	Consolidated Edison Co of New York Inc	Unsecured	500	5.200%	Baa1	A-	03/01/33	+125
80	02/22/23	NEE	NextEra Energy Capital Holdings Inc	Unsecured	2,500	6.051%	Baa1	BBB+	03/01/25	+120
81	02/27/23	AEE	Union Electric Co	Secured	500	5.450%	A2	A	03/15/53	+155
82	02/27/23	AEP	American Electric Power Co Inc	Unsecured	850	5.625%	Baa2	BBB	03/01/33	+175
83	02/27/23	DTE	DTE Electric Co	Secured	600	5.200%	Aa3	A	04/01/33	+130
84	02/27/23	DTE	DTE Electric Co	Secured	600	5.400%	Aa3	A	04/01/53	+148
85	02/27/23	EIX	Southern California Edison Co	Secured	750	5.300%	A2	A-	03/01/28	+115
86	02/27/23	EIX	Southern California Edison Co	Secured	450	5.700%	A2	A-	03/01/53	+180
87	02/27/23	PPL	PPL Electric Utilities Corp	Secured	600	5.000%	A1	A+	05/15/33	+120
88	02/27/23	PPL	PPL Electric Utilities Corp	Secured	750	5.250%	A1	A+	05/15/53	+145
89	02/28/23	NEE	Florida Power & Light Co	Secured	1,000	5.050%	Aa2	A+	04/01/28	+90
90	02/28/23	NEE	Florida Power & Light Co	Secured	750	5.100%	Aa2	A+	04/01/33	+120
91	02/28/23	NEE	Florida Power & Light Co	Secured	750	5.300%	Aa2	A+	04/01/53	+140
92	03/01/23	EIX	Edison International	Unsecured	500	8.125%	Baa3	BB+	06/15/53	+386
93	03/01/23	ES	Eversource Energy	Unsecured	750	5.450%	Baa1	BBB+	03/01/28	+123
94	03/01/23	NGGLN	KeySpan Gas East Corp	Unsecured	500	5.994%	Baa1	BBB+	03/06/33	+200
95	03/02/23	BKH	Black Hills Corp	Unsecured	350	5.950%	Baa2	BBB+	03/15/28	+170
96	03/02/23	NRG	NRG Energy Inc	Secured	740	7.000%	Baa3	BBB-	03/15/33	+310
97	03/02/23	NRG	NRG Energy Inc	Unsecured	650	10.250%	Ba3	B	PerpNC5	+592
98	03/02/23	NWN	Northwest Natural Gas Co	Secured	100	5.750%	A2	AA-	03/15/33	+170
99	03/06/23	DUK	Duke Energy Progress LLC	Secured	500	5.250%	Aa3	A	03/15/33	+128
100	03/06/23	DUK	Duke Energy Progress LLC	Secured	500	5.350%	Aa3	A	03/15/53	+148

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Recent Utility Corporate Bond Issuances
for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-31 (MRB-9)
Page: 3 of 6
Witness: MRBleckman
Date: December 2024

Line No.	(a) Issue Date	(b) Ticker	(c) Issuer	(d) Type	(e) Amt ($mm)	(f) Coupon	(g) Ratings Moody's	(h) Ratings S&P	(i) Maturity	(j) Issue Spread (bp)
1	03/06/23	SRE	San Diego Gas & Electric Co	Secured	800	5.350%	A1	A	04/01/53	+150
2	03/07/23	EVRG	Evergy Kansas Central Inc	Secured	400	5.700%	A2	A	03/15/53	+185
3	03/08/23	ETR	System Energy Resources Inc	Secured	325	6.000%	Baa1	A	04/15/28	+255
4	03/09/23	AEP	AEP Transmission Co LLC	Secured	700	5.400%	A2	A-	03/15/53	+157
5	03/09/23	IDA	Idaho Power Co	Secured	400	5.500%	A2	A-	03/15/53	+170
6	03/09/23	PPL	Kentucky Utilities Co	Secured	400	5.450%	A1	A	04/15/33	+155
7	03/09/23	PPL	Louisville Gas and Electric Co	Secured	400	5.450%	A1	A	04/15/33	+155
8	03/20/23	CNP	CenterPoint Energy Houston Electric LLC	Secured	600	4.950%	A2	A	04/01/33	+150
9	03/20/23	CNP	CenterPoint Energy Houston Electric LLC	Secured	300	5.300%	A2	A	04/01/53	+165
10	03/20/23	DUK	Duke Energy Ohio Inc	Secured	375	5.250%	A2	A	04/01/33	+175
11	03/20/23	DUK	Duke Energy Ohio Inc	Secured	375	5.650%	A2	A	04/01/53	+200
12	03/21/23	AEP	Indiana Michigan Power Co	Unsecured	500	5.625%	A3	A-	04/01/53	+190
13	03/21/23	DUK	Duke Energy Indiana LLC	Secured	500	5.400%	Aa3	A	04/01/53	+170
14	03/21/23	NI	NiSource Inc	Unsecured	750	5.250%	Baa2	BBB+	03/30/28	+155
15	03/21/23	OGE	Oklahoma Gas and Electric Co	Unsecured	350	5.600%	A3	A-	04/01/53	+190
16	03/21/23	SWX	Southwest Gas Corp	Unsecured	300	5.450%	Baa1	BBB	03/23/28	+175
17	03/23/23	PEG	Public Service Electric and Gas Co	Secured	500	4.650%	A1	A	03/15/33	+122
18	03/23/23	PEG	Public Service Electric and Gas Co	Secured	400	5.125%	A1	A	03/15/53	+142
19	03/27/23	LNT	Wisconsin Power & Light	Unsecured	300	4.950%	A3	A	04/01/33	+145
20	03/27/23	TVA	Tennessee Valley Authority	Unsecured	1,000	3.875%	Aaa	AA+	03/15/28	+45
21	03/27/23	XEL	Public Service Co of Colorado	Secured	850	5.250%	A1	A	04/01/53	+155
22	03/28/23	AEP	Southwestern Electric Power Co	Unsecured	350	5.300%	Baa2	A-	04/01/33	+178
23	03/28/23	D	Virginia Electric Power Co	Unsecured	750	5.000%	A2	BBB+	04/01/33	+150
24	03/28/23	D	Virginia Electric Power Co	Unsecured	750	5.450%	A2	BBB+	04/01/53	+175
25	03/28/23	FE	Metropolitan Edison Co	Unsecured	425	5.200%	A3	BBB	04/01/28	+160
26	03/28/23	FE	Pennsylvania Electric Co	Unsecured	300	5.150%	Baa1	BBB	03/30/26	+140
27	03/28/23	PCG	Pacific Gas and Electric Co	Secured	750	6.700%	Baa3	BBB-	04/01/53	+295
28	04/03/23	EVRG	Evergy Metro Inc	Secured	300	4.950%	A2	A+	04/15/33	+153
29	04/04/23	WEC	WEC Energy Group Inc (reopening)	Unsecured	350	4.750%	Baa1	BBB+	01/09/26	+100
30	04/19/23	EIX	SCE Recovery Funding LLC	Secured	425	4.697%	Aaa	AAA	06/15/40	+110
31	04/19/23	EIX	SCE Recovery Funding LLC	Secured	350	5.112%	Aaa	AAA	12/15/47	+120
32	05/01/23	CNP	CenterPoint Energy Resources Corp (Reopening)	Unsecured	300	5.250%	A3	BBB+	03/01/28	+100
33	05/01/23	SO	Georgia Power Co	Unsecured	750	4.650%	Baa1	BBB+	05/16/28	+105
34	05/01/23	SO	Georgia Power Co	Unsecured	1,000	4.950%	Baa1	BBB+	05/17/33	+140
35	05/01/23	XEL	Northern States Power Company	Secured	800	5.100%	Aa3	A	05/15/53	+135
36	05/08/23	AEP	Ohio Power Co	Unsecured	400	5.000%	Baa1	A-	06/01/33	+155
37	05/08/23	DTE	DTE Energy Co	Unsecured	800	4.875%	Baa2	BBB	06/01/28	+140
38	05/08/23	ES	Eversource Energy	Unsecured	450	4.750%	Baa1	BBB+	05/15/26	+105
39	05/08/23	ES	Eversource Energy	Unsecured	550	5.450%	Baa1	BBB+	03/01/28	+130
40	05/08/23	ES	Eversource Energy	Unsecured	800	5.125%	Baa1	BBB+	05/15/33	+163
41	05/08/23	EXC	Baltimore Gas and Electric Co	Unsecured	700	5.400%	A3	A	06/01/53	+158
42	05/08/23	ONCRTX	Oncor Electric Delivery Co	Secured	600	4.300%	A2	A+	05/15/28	+85
43	05/08/23	ONCRTX	Oncor Electric Delivery Co (reopening)	Secured	400	4.950%	A2	A+	09/15/52	+145
44	05/09/23	ETR	Entergy Mississippi LLC	Secured	300	5.000%	A2	A	09/01/33	+148
45	05/10/23	EIX	Edison International	Unsecured	600	5.250%	Baa2	BBB-	11/15/28	+190
46	05/15/23	AES	The AES Corp	Unsecured	900	5.450%	Baa3	BBB-	06/01/28	+200
47	05/15/23	BRKHEC	PacifiCorp	Secured	1,200	5.500%	A1	A+	05/15/54	+165
48	05/15/23	NEE	Florida Power & Light Co	Unsecured	500	4.450%	A1	A	05/15/26	+80
49	05/15/23	NEE	Florida Power & Light Co	Secured	750	4.400%	Aa2	A+	05/15/28	+95
50	05/15/23	NEE	Florida Power & Light Co	Secured	500	4.625%	Aa2	A+	05/15/30	+115
51	05/15/23	NEE	Florida Power & Light Co	Secured	750	4.800%	Aa2	A+	05/15/33	+130
52	05/15/23	PSD	Puget Sound Energy Inc	Secured	400	5.448%	A2	A-	06/01/53	+160
53	05/15/23	SO	The Southern Co	Unsecured	750	4.850%	Baa2	BBB	06/15/28	+143
54	05/15/23	SO	The Southern Co	Unsecured	750	5.200%	Baa2	BBB	06/15/33	+173
55	05/17/23	EDF FP	Electricite de France SA	Unsecured	1,000	5.700%	Baa1	BBB	05/23/28	+215
56	05/17/23	EDF FP	Electricite de France SA	Unsecured	1,000	6.250%	Baa1	BBB	05/23/33	+270
57	05/17/23	EDF FP	Electricite de France SA	Unsecured	1,000	6.900%	Baa1	BBB	05/23/53	+310
58	05/17/23	EIX	Southern California Edison Co	Secured	400	4.900%	A2	A-	06/01/26	+113
59	05/17/23	EIX	Southern California Edison Co	Secured	700	5.875%	A2	A-	12/01/53	+200
60	05/17/23	ITC	ITC Holdings Corp	Unsecured	500	5.400%	Baa2	BBB+	06/01/33	+185
61	05/17/23	ITC	ITC Holdings Corp (reopening)	Unsecured	300	4.950%	Baa2	BBB+	09/22/27	+135
62	05/17/23	NRUC	National Rural Utilities Cooperative Finance Corp	Pref/Hybrid	300	7.125%	A3	BBB	09/15/53	+353
63	05/17/23	SRE	Southern California Gas Co	Secured	500	5.200%	Aa3	A+	06/01/33	+165
64	05/17/23	SRE	Southern California Gas Co	Secured	500	5.750%	Aa3	A+	06/01/53	+190
65	05/22/23	AEP	AEP Texas Inc	Unsecured	450	5.400%	Baa2	A-	06/01/33	+172
66	05/23/23	AEE	Ameren Illinois Company	Secured	500	4.950%	A1	A	06/01/33	+127
67	05/30/23	NI	NiSource Inc.	Unsecured	450	5.400%	Baa2	BBB+	06/30/33	+175
68	05/30/23	NI	NiSource Inc.(Reopening)	Unsecured	300	5.250%	Baa2	BBB+	03/30/28	+135
69	05/31/23	AEP	American Electric Power Co Inc	Jr. Sub Notes	850	5.699%	Baa3	BBB+	08/15/25	+155
70	06/01/23	PCG	Pacific Gas and Electric Co	Secured	850	6.100%	Baa3	BBB-	01/15/29	+240
71	06/01/23	PCG	Pacific Gas and Electric Co	Secured	1,150	6.400%	Baa3	BBB-	06/15/33	+280
72	06/01/23	PCG	Pacific Gas and Electric Co (Reopening)	Secured	500	6.750%	Baa3	BBB-	01/15/53	+315
73	06/05/23	DUK	Piedmont Natural Gas Co	Unsecured	350	5.400%	A3	BBB+	06/15/33	+170
74	06/08/23	VST	Palomino Funding Trust I	Secured	450	7.233%	Baa3	BBB-	05/17/28	+338
75	06/13/23	DUK	Duke Energy Carolinas LLC	Secured	500	5.400%	Aa3	A	01/15/54	+150
76	06/13/23	DUK	Duke Energy Carolinas LLC (Reopening)	Secured	350	4.950%	Aa3	A	01/15/33	+130
77	06/15/23	EXC	PECO Energy Co	Secured	575	4.900%	Aa3	A	06/15/33	+120
78	06/20/23	SRE	Sempra Energy	Unsecured	550	5.400%	Baa2	BBB	08/01/26	+123
79	06/20/23	SRE	Sempra Energy	Unsecured	700	5.500%	Baa2	BBB	08/01/33	+180
80	06/21/23	CNP	SIGECO Securitization I	Secured	215	5.026%	Aaa	AAA	11/15/38	+118
81	06/21/23	CNP	SIGECO Securitization I	Secured	126	5.172%	Aaa	AAA	05/15/43	+145
82	06/26/23	ES	The Connecticut Light & Power Co	Secured	300	4.900%	A1	A+	07/01/33	+120
83	06/26/23	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	400	5.050%	A2	A-	09/15/28	+110
84	06/27/23	PNW	Arizona Public Service Co	Unsecured	500	5.550%	A3	BBB+	08/01/33	+180
85	07/17/23	NGGLN	Boston Gas Company	Unsecured	400	6.119%	Baa1	BBB+	07/20/53	+218
86	**07/31/23**	**CMS**	**Consumers Energy Company**	**Unsecured**	**500**	**4.900%**	**A1**	**A**	**02/15/29**	**+75**
87	07/31/23	XEL	Xcel Energy	Unsecured	800	5.450%	Baa1	BBB+	08/15/33	+153
88	08/03/23	AGR	New York State Electric & Gas	Unsecured	350	5.650%	Baa1	A-	08/15/28	+140
89	08/03/23	AGR	New York State Electric & Gas	Unsecured	400	5.850%	Baa1	A-	08/15/33	+168
90	08/03/23	PEG	Public Service Electric and Gas Co	Secured	500	5.200%	A1	A	08/01/33	+103
91	08/03/23	PEG	Public Service Electric and Gas Co	Secured	400	5.450%	A1	A	08/01/53	+115
92	08/07/23	NEE	NextEra Energy Capital Holdings	Unsecured	2,000	5.749%	Baa1	BBB+	09/01/25	+100
93	08/07/23	SRE	SDG&E	Secured	600	4.950%	A1	A	08/15/28	+90
94	08/08/23	CNP	CenterPoint Energy Inc	Unsecured	400	5.250%	Baa2	BBB	08/10/26	+90
95	08/08/23	D	Virginia Electric Power Co	Unsecured	400	5.300%	A2	BBB+	08/15/33	+128
96	08/08/23	D	Virginia Electric Power Co	Unsecured	600	5.700%	A2	BBB+	08/15/53	+150
97	08/08/23	ETR	Entergy Texas	Secured	350	5.800%	A3	A	09/01/53	+160
98	08/14/23	ETR	Entergy Arkansas	Secured	300	5.300%	A2	A	09/15/33	+120
99	08/15/23	NRG	Alexander Funding Trust	Secured	500	7.467%	Baa3	BBB-	07/31/28	+310
100	09/05/23	SO	The Southern Co	Unsecured	600	5.500%	Baa2	BBB	03/15/29	+113

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Recent Utility Corporate Bond Issuances
for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-31 (MRB-9)
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Witness: MRBleckman
Date: December 2024

Line No.	(a) Issue Date	(b) Ticker	(c) Issuer	(d) Type	(e) Amt ($mm)	(f) Coupon	(g) Ratings Moody's	(h) Ratings S&P	(i) Maturity	(j) Issue Spread (bp)
1	09/05/23	SO	The Southern Co	Unsecured	700	5.700%	Baa2	BBB	03/15/34	+148
2	09/05/23	DUK	Duke Energy Corp	Unsecured	600	5.750%	Baa2	BBB	09/15/33	+150
3	09/05/23	DUK	Duke Energy Corp	Unsecured	750	6.100%	Baa2	BBB	09/15/53	+173
4	09/05/23	BRKHEC	MidAmerican Energy Co	Secured	350	5.350%	Aa2	A+	01/15/34	+110
5	09/05/23	BRKHEC	MidAmerican Energy Co	Secured	1,000	5.850%	Aa2	A+	09/15/54	+147
6	09/05/23	WEC	WEC Energy Group Inc	Unsecured	600	5.600%	Baa1	BBB+	09/12/26	+93
7	09/06/23	BKH	Black Hills Corporation	Unsecured	450	6.150%	Baa2	BBB+	05/14/34	+195
8	09/06/23	IDA	Idaho Power Co	Secured	350	5.800%	A2	A-	04/01/54	+150
9	09/11/23	SO	Southern Company Gas Capital Corp	Unsecured	500	5.750%	Baa1	BBB+	09/15/33	+148
10	09/11/23	BRKHEC	Nevada Power Co	Secured	500	6.000%	A2	A+	03/15/54	+163
11	09/12/23	VST	Vistra Operations Co LLC	Secured	650	6.950%	Baa3	BBB-	10/15/33	+270
12	09/12/23	FE	Monongahela Power Co	Secured	400	5.850%	A3	A-	02/15/34	+160
13	09/12/23	NGGLN	Brooklyn Union Gas Company	Unsecured	400	6.388%	Baa2	BBB+	09/15/33	+212
14	09/13/23	CNP	CenterPoint Energy Houston Electric LLC	Secured	500	5.200%	A2	A	10/01/28	+85
15	09/13/23	BRKHEC	Sierra Pacific Power Co	Secured	400	5.900%	A2	A+	03/15/54	+160
16	09/18/23	LNT	Interstate Power and Light Co	Unsecured	300	5.700%	Baa1	A-	10/15/33	+145
17	09/18/23	ES	Public Service Co of New Hampshire	Secured	300	5.350%	A1	A+	10/01/33	+105
18	09/18/23	ES	NSTAR Electric Co	Unsecured	150	5.600%	A1	A	10/01/28	+115
19	09/26/23	CEG	Constellation Energy Generation LLC	Unsecured	500	6.125%	Baa2	BBB	01/15/34	+158
20	09/26/23	CEG	Constellation Energy Generation LLC	Unsecured	900	6.500%	Baa2	BBB	10/01/53	+180
21	09/26/23	EIX	Southern California Edison Co	Secured	550	5.650%	A2	A-	10/01/28	+105
22	10/02/23	PEG	Public Service Enterprise Group	Unsecured	600	5.875%	Baa2	BBB	10/15/28	+120
23	10/02/23	PEG	Public Service Enterprise Group	Unsecured	400	6.125%	Baa2	BBB	10/15/33	+150
24	10/04/23	D	Dominion Energy South Carolina Inc	Secured	500	6.250%	A2	A	10/15/53	+140
25	10/05/23	ATO	Atmos Energy	Unsecured	400	5.900%	A1	A-	11/15/33	+120
26	10/05/23	ATO	Atmos Energy	Unsecured	500	6.200%	A1	A-	11/15/53	+133
27	10/30/23	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	400	5.600%	A2	A-	11/13/26	+73
28	11/06/23	DUK	Duke Energy Florida LLC	Secured	600	5.875%	A1	A	11/15/33	+125
29	11/06/23	DUK	Duke Energy Florida LLC	Secured	700	6.200%	A1	A	11/15/53	+142
30	11/06/23	PCG	Pacific Gas and Electric Co	Secured	800	6.950%	Baa3	BBB-	03/15/34	+233
31	11/06/23	SO	Alabama Power Co	Unsecured	300	5.850%	A1	A-	11/15/33	+120
32	11/07/23	LNT	Alliant Energy Finance LLC	Unsecured	300	5.950%	Baa2	BBB+	03/30/29	+147
33	11/08/23	AEP	Kentucky Power Co	Unsecured	375	7.000%	Baa3	BBB	11/15/33	+250
34	11/08/23	ES	Eversource Energy	Unsecured	800	5.950%	Baa2	BBB+	02/01/29	+147
35	11/08/23	EVRG	Evergy Kansas Central Inc	Secured	300	5.900%	A2	A	11/15/33	+140
36	11/08/23	ONCRTX	Oncor Electric Delivery Co LLC	Secured	800	5.650%	A2	A+	11/15/33	+115
37	11/15/23	AEE	Ameren Corporation	Unsecured	600	5.700%	Baa1	BBB	12/01/26	+105
38	11/20/23	ED	Consolidated Edison Co of New York Inc	Unsecured	600	5.500%	A3	A-	03/15/34	+115
39	11/20/23	ED	Consolidated Edison Co of New York Inc	Unsecured	900	5.900%	A3	A-	11/15/53	+138
40	11/28/23	OGLETH	Oglethorpe Power Corp	Secured	400	6.200%	Baa1	BBB+	12/01/53	+175
41	12/04/23	EIX	Edison International	Pref/Hybrid	450	7.875%	Baa3	BB+	06/15/54	+366
42	12/06/23	AEP	American Electric Power Company	Unsecured	1,000	5.200%	Baa2	BBB+	01/15/29	+113
43	12/11/23	OGS	ONE Gas Inc	Unsecured	300	5.100%	A3	A-	4/1/2029	+87
44	12/11/23	VST	Vistra Operations Co LLC (Reopening)	Secured	400	6.950%	Baa3	BBB-	10/15/33	+240
45	12/18/23	AEE	Ameren Corporation	Unsecured	700	5.000%	Baa2	BBB	01/15/29	+110
46	01/02/24	DUK	Duke Energy Corp	Unsecured	550	4.850%	Baa2	BBB	1/5/2027	+75
47	01/02/24	DUK	Duke Energy Corp	Unsecured	550	4.850%	Baa2	BBB	1/5/2029	+95
48	01/02/24	D	Virginia Electric and Power Co	Unsecured	500	5.000%	A2	BBB+	01/15/34	+115
49	01/02/24	D	Virginia Electric and Power Co	Unsecured	500	5.350%	A2	BBB+	01/15/54	+127
50	01/02/24	PPL	PPL Electric Utilities Corp	Secured	650	4.850%	A1	A+	02/15/34	+92
51	**01/02/24**	**CMS**	**Consumers Energy Co**	**Secured**	**600**	**4.600%**	**A1**	**A**	**05/30/29**	**+73**
52	01/03/24	BRKHEC	PacifiCorp	Secured	500	5.100%	A2	A	02/15/29	+120
53	01/03/24	BRKHEC	PacifiCorp	Secured	700	5.300%	A2	A	02/15/31	+140
54	01/03/24	BRKHEC	PacifiCorp	Secured	1,100	5.450%	A2	A	02/15/34	+155
55	01/03/24	BRKHEC	PacifiCorp	Secured	1,500	5.800%	A2	A	01/15/55	+175
56	01/03/24	DUK	Duke Energy Carolinas LLC	Secured	575	4.850%	Aa3	A	01/15/34	+100
57	01/03/24	DUK	Duke Energy Carolinas LLC (Reopening)	Secured	425	5.400%	Aa3	A	01/15/54	+118
58	01/03/24	AEE	Union Electric Co	Secured	350	5.250%	A2	A	01/15/54	+123
59	01/04/24	WTRG	Essential Utilities Inc	Unsecured	500	5.375%	Baa2	A-	01/15/34	+140
60	01/08/24	EIX	Southern California Edison Co	Secured	500	4.875%	A2	A-	02/01/27	+75
61	01/08/24	EIX	Southern California Edison Co	Secured	900	5.200%	A2	A-	06/01/34	+120
62	01/08/24	NGGLN	National Grid PLC	Unsecured	750	5.418%	Baa2	BBB	01/11/34	+142
63	01/09/24	AQNCN	Liberty Utilities Co	Unsecured	500	5.577%	Baa2	BBB	01/31/29	+160
64	01/09/24	AQNCN	Liberty Utilities Co	Unsecured	350	5.869%	Baa2	BBB	01/31/34	+185
65	01/11/24	NGGLN	Niagara Mohawk Power	Unsecured	500	5.290%	Baa1	BBB+	01/17/34	+130
66	01/11/24	NGGLN	Niagara Mohawk Power	Unsecured	700	5.664%	Baa1	BBB+	01/17/54	+145
67	01/16/24	ES	Eversource Energy	Unsecured	350	5.000%	Baa2	BBB+	1/1/2027	+100
68	01/16/24	ES	Eversource Energy	Unsecured	650	5.500%	Baa2	BBB+	1/1/2034	+150
69	01/16/24	ES	Connecticut Light and Power Co	Secured	350	4.650%	A1	A+	1/1/2029	+75
70	01/22/24	BRKHEC	MidAmerican Energy	Secured	600	5.300%	Aa2	A	02/01/55	+98
71	01/25/24	TE	Tampa Electric	Unsecured	500	4.900%	A3	BBB+	03/01/29	+88
72	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	600	FRN	Baa1	BBB+	01/29/26	+76
73	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	1,000	4.950%	Baa1	BBB+	01/29/26	+65
74	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	900	4.900%	Baa1	BBB+	03/15/29	+95
75	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	1,100	5.250%	Baa1	BBB+	03/15/34	+120
76	01/29/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	800	5.550%	Baa1	BBB+	03/15/54	+125
77	01/29/24	BRKHEC	Northern Natural Gas Co	Unsecured	500	5.625%	A2	A-	02/01/54	+127
78	02/06/24	SR	Spire Inc	Unsecured	350	5.300%	Baa2	BBB+	03/01/26	+85
79	02/12/24	DTE	DTE Energy Co	Unsecured	1,200	5.100%	Baa2	BBB	03/01/29	+103
80	02/20/24	AWK	American Water Capital Corp	Unsecured	700	5.150%	Baa1	A	03/01/34	+92
81	02/20/24	AWK	American Water Capital Corp	Unsecured	700	5.450%	Baa1	A	03/01/54	+107
82	02/20/24	SO	Georgia Power Co	Unsecured	500	5.004%	Baa1	BBB+	02/23/27	+62
83	02/20/24	SO	Georgia Power Co	Unsecured	900	5.250%	Baa1	BBB+	03/15/34	+102
84	02/20/24	DTE	DTE Electric Co	Secured	500	4.850%	Aa3	A	12/01/26	+47
85	02/20/24	DTE	DTE Electric Co	Secured	500	5.200%	Aa3	A	03/01/34	+93
86	02/21/24	NGGLN	Massachusetts Electric Co	Unsecured	400	5.867%	Baa1	BBB+	02/26/54	+138
87	02/22/24	EXC	Exelon Corp	Unsecured	650	5.150%	Baa2	BBB	03/15/29	+88
88	02/22/24	EXC	Exelon Corp	Unsecured	650	5.450%	Baa2	BBB	03/15/34	+115
89	02/22/24	EXC	Exelon Corp (Reopening)	Unsecured	400	5.600%	Baa2	BBB	03/15/53	+130
90	02/22/24	XEL	Northern States Power Co/MN	Secured	700	5.400%	Aa3	A+	03/15/54	+97
91	02/26/24	PCG	Pacific Gas and Electric Co	Secured	850	5.550%	Baa2	BBB	05/15/29	+125
92	02/26/24	PCG	Pacific Gas and Electric Co	Secured	1,100	5.800%	Baa2	BBB	05/15/34	+153
93	02/26/24	PCG	Pacific Gas and Electric Co (Reopening)	Secured	300	6.750%	Baa2	BBB	01/15/53	+170
94	02/26/24	SO	The Southern Co (Reopening)	Unsecured	400	5.500%	Baa2	BBB	03/15/29	+85
95	02/26/24	SO	The Southern Co (Reopening)	Unsecured	400	5.700%	Baa2	BBB	03/15/34	+117
96	02/26/24	XEL	Xcel Energy Inc	Unsecured	800	5.500%	Baa1	BBB+	03/15/34	+125
97	02/26/24	EXC	Potomac Electric Power Co	Secured	375	5.200%	A2	A	03/15/34	+95
98	02/26/24	EXC	Potomac Electric Power Co	Secured	300	5.500%	A2	A	03/15/54	+110
99	02/26/24	CNP	CenterPoint Energy Houston Electric LLC	Secured	400	5.150%	A2	A	03/01/34	+90
100	02/26/24	DUK	Duke Energy Indiana LLC	Secured	300	5.250%	Aa3	A	03/01/34	+100

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Recent Utility Corporate Bond Issuances
for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-31 (MRB-9)
Page: 5 of 6
Witness: MRBleckman
Date: December 2024

Line No.	(a) Issue Date	(b) Ticker	(c) Issuer	(d) Type	(e) Amt ($mm)	(f) Coupon	(g) Ratings Moody's	(h) Ratings S&P	(i) Maturity	(j) Issue Spread (bp)
1	02/27/24	EIX	Southern California Edison Co	Secured	600	5.350%	A2	A-	03/01/26	+62
2	02/27/24	EIX	Southern California Edison Co	Secured	600	5.150%	A2	A-	06/01/29	+83
3	02/27/24	EIX	Southern California Edison Co	Secured	400	5.750%	A2	A-	04/15/54	+135
4	02/27/24	NEE	NextEra Energy Capital Holdings Inc	Pref/Hybrid	1,000	6.700%	Baa2	BBB	09/01/54	+242
5	02/28/24	PEG	Public Service Electric and Gas Co	Secured	450	5.200%	A1	A	03/01/34	+93
6	02/28/24	PEG	Public Service Electric and Gas Co	Secured	550	5.450%	A1	A	03/01/54	+108
7	03/04/24	NEE	NextEra Energy Capital Holdings Inc	Unsecured	1,000	4.850%	Baa1	BBB+	04/30/31	+142
8	03/04/24	ETR	Entergy Louisiana LLC	Secured	500	5.350%	A2	A	03/15/34	+115
9	03/04/24	ETR	Entergy Louisiana LLC	Secured	700	5.700%	A2	A	03/15/54	+135
10	03/04/24	LNT	Wisconsin Power and Light Co	Unsecured	300	5.375%	Baa1	A	03/30/34	+118
11	03/06/24	AES	AES Andes SA	Unsecured	500	6.300%	Baa3	BBB-	03/15/29	+220
12	03/07/24	AES	Indianapolis Power & Light Co	Secured	650	5.700%	A2	A-	04/01/54	+147
13	03/08/24	AES	IPALCO Enterprises Inc	Secured	400	5.750%	Baa3	BBB-	04/01/34	+170
14	03/11/24	NI	NiSource Inc	Unsecured	650	5.350%	Baa2	BBB+	04/01/34	+128
15	03/11/24	SRE	Sempra Energy	Pref/Hybrid	600	6.875%	Baa3	BBB-	10/01/54	+279
16	03/11/24	DUK	Duke Energy Progress LLC	Secured	500	5.100%	Aa3	A	03/15/34	+103
17	03/11/24	AEP	AEP Transmission Co LLC	Unsecured	450	5.150%	A2	BBB+	04/01/34	+105
18	03/11/24	DUK	Duke Energy Ohio Inc	Secured	425	5.550%	A2	A	03/15/54	+130
19	03/12/24	CEG	Constellation Energy Generation LLC	Unsecured	900	5.750%	Baa2	BBB+	03/15/54	+145
20	03/12/24	SRE	Southern California Gas Co	Secured	500	5.600%	Aa3	A+	04/01/54	+133
21	03/18/24	SRE	San Diego Gas & Electric Co	Secured	600	5.550%	A1	A	04/15/54	+115
22	03/18/24	AEP	Appalachian Power Co	Unsecured	400	5.650%	Baa1	BBB+	04/01/34	+135
23	03/19/24	ES	Public Service Co of New Hampshire (Reopening)	Secured	300	5.350%	A1	A+	10/01/33	+95
24	03/21/24	PPL	The Narragansett Electric Co	Unsecured	500	5.350%	A3	A-	05/01/34	+108
25	03/25/24	PEG	Public Service Enterprise Group Inc	Unsecured	750	5.200%	Baa2	BBB	04/01/29	+100
26	03/25/24	PEG	Public Service Enterprise Group Inc	Unsecured	500	5.450%	Baa2	BBB	04/01/34	+122
27	03/25/24	AEE	Union Electric Company d/b/a Ameren Missouri	Secured	500	5.200%	A2	A	04/01/34	+98
28	04/01/24	XEL	Public Service Co of Colorado	Secured	450	5.350%	A1	A	05/15/34	+105
29	04/01/24	XEL	Public Service Co of Colorado	Secured	750	5.750%	A1	A	05/15/54	+130
30	04/01/24	EVRG	Evergy Metro Inc	Secured	300	5.400%	A2	A	04/01/34	+110
31	04/03/24	ENGIFP	Engie SA	Unsecured	750	5.250%	Baa1	BBB+	04/10/29	+100
32	04/03/24	ENGIFP	Engie SA	Unsecured	750	5.625%	Baa1	BBB+	04/10/34	+128
33	04/03/24	ENGIFP	Engie SA	Unsecured	500	5.875%	Baa1	BBB+	04/10/54	+148
34	04/09/24	DUK	Duke Energy Corporation	Unsecured	750	3.750%	Baa2	BBB	04/01/31	MS+120
35	04/09/24	VST	Vistra Operations Co LLC	Secured	500	6.000%	Baa3	BBB-	04/15/34	+165
36	04/11/24	RWE	RWE Finance US LLC	Unsecured	1,000	5.875%	Baa2	NR	04/16/34	+135
37	04/11/24	RWE	RWE Finance US LLC	Unsecured	1,000	6.250%	Baa2	NR	04/16/54	+160
38	04/15/24	EDF	Electricite de France SA	Unsecured	650	5.650%	Baa1	BBB	04/22/29	+105
39	04/15/24	EDF	Electricite de France SA	Unsecured	650	5.950%	Baa1	BBB	04/22/34	+135
40	04/15/24	EDF	Electricite de France SA	Unsecured	750	6.000%	Baa1	BBB	04/22/64	+185
41	04/15/24	ES	Eversource Energy	Unsecured	700	5.850%	Baa2	BBB+	04/15/31	+120
42	04/15/24	ES	Eversource Energy	Unsecured	700	5.950%	Baa2	BBB+	07/15/34	+135
43	04/29/24	DTE	DTE Energy Co	Unsecured	850	5.850%	Baa2	BBB	06/01/34	+125
44	05/02/24	AEP	Ohio Power Co	Unsecured	350	5.650%	Baa1	BBB+	06/01/34	+110
45	05/06/24	D	Dominion Energy Inc	Pref/Hybrid	1,000	6.875%	Baa3	BBB-	02/01/55	+239
46	05/06/24	D	Dominion Energy Inc	Pref/Hybrid	1,000	7.000%	Baa3	BBB-	06/01/54	+251
47	05/06/24	ED	Consolidated Edison Co of New York Inc	Unsecured	400	5.375%	A3	A-	05/15/34	+90
48	05/06/24	ED	Consolidated Edison Co of New York Inc	Unsecured	1,000	5.700%	A3	A-	05/15/54	+110
49	05/06/24	EXC	Commonwealth Edison Co	Secured	400	5.300%	A1	A	06/01/34	+85
50	05/06/24	EXC	Commonwealth Edison Co	Secured	400	5.650%	A1	A	06/01/54	+105
51	05/06/24	EIX	Southern California Edison Co	Secured	750	5.450%	A2	A-	06/01/31	+97
52	05/06/24	PNW	Arizona Public Service Co	Unsecured	450	5.700%	Baa1	BBB+	08/15/34	+125
53	05/06/24	ITC	ITC Holdings Corp	Unsecured	400	5.650%	Baa2	BBB+	05/09/34	+118
54	05/06/24	OGE	OGE Energy Corp	Unsecured	350	5.450%	Baa1	BBB	05/15/29	+100
55	05/07/24	EIX	SCE Trust VIII ($25 par)	Pref/Hybrid	350	6.950%	Baa3	BB+	05/13/29	+248
56	05/07/24	ETR	Entergy Arkansas LLC	Secured	400	5.450%	A2	A	06/01/34	+100
57	05/07/24	ETR	Entergy Arkansas LLC	Secured	400	5.750%	A2	A	06/01/54	+118
58	05/07/24	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	450	5.100%	A2	A-	05/06/27	+48
59	05/07/24	NRUC	National Rural Utilities Cooperative Finance Corp	Unsecured	350	5.150%	A2	A-	06/15/29	+73
60	05/07/24	WEC	Wisconsin Electric Power Co	Unsecured	350	5.000%	A2	A-	05/15/29	+60
61	05/08/24	CNP	CenterPoint Energy Inc	Unsecured	700	5.400%	Baa2	BBB	06/01/29	+95
62	05/13/24	NI	NiSource	Pref/Hybrid	500	6.950%	Baa3	BBB-	11/30/54	+245
63	05/13/24	BKH	Black Hills Corporation	Unsecured	450	6.000%	Baa2	BBB+	01/15/35	+155
64	05/13/24	XEL	Northern States Power - WI	Secured	400	5.650%	Aa3	A	06/15/54	+105
65	05/13/24	ETR	Entergy Mississippi	Secured	300	5.850%	A2	A	06/01/54	+123
66	05/15/24	ONCRTX	Oncor Electric Delivery Company	Secured	500	3.500%	A2	A+	05/15/31	MS+80
67	05/16/24	AES	The AES Corp	Pref/Hybrid	950	7.600%	Ba1	BB	01/15/55	+320
68	05/20/24	ETR	Entergy Corp	Pref/Hybrid	1,200	7.125%	Baa3	BBB-	12/01/54	+267
69	05/20/24	AEP	AEP Texas Inc	Unsecured	500	5.450%	Baa2	BBB+	05/15/29	+100
70	05/20/24	AEP	AEP Texas Inc	Unsecured	350	5.700%	Baa2	BBB+	05/15/34	+130
71	05/20/24	ES	NSTAR Electric Co	Unsecured	600	5.400%	A2	A	06/01/34	+98
72	05/21/24	EVRG	Evergy Missouri West Inc	Secured	300	5.650%	A3	A	06/01/34	+125
73	05/28/24	NEE	Florida Power & Light Co	Secured	750	5.150%	Aa2	A+	06/15/29	+60
74	05/28/24	NEE	Florida Power & Light Co	Secured	750	5.300%	Aa2	A+	06/15/34	+80
75	05/28/24	NEE	Florida Power & Light Co	Secured	850	5.600%	Aa2	A+	06/15/54	+95
76	05/28/24	SRE	Sempra Energy (Reopening)	Pref/Hybrid	500	6.875%	Baa3	BBB-	10/01/54	+279
77	06/03/24	EXC	Baltimore Gas and Electric Co	Unsecured	400	5.300%	A3	A	06/01/34	+93
78	06/03/24	EXC	Baltimore Gas and Electric Co	Unsecured	400	5.650%	A3	A	06/01/54	+110
79	06/03/24	XEL	Southwestern Public Service Co	Secured	600	6.000%	A3	A-	06/01/54	+150
80	06/03/24	LNT	Alliant Energy Finance LLC	Unsecured	375	5.400%	Baa2	BBB+	06/06/27	+80
81	06/04/24	PSD	Puget Sound Energy Inc	Unsecured	400	5.330%	A2	A-	06/15/34	+100
82	06/04/24	PSD	Puget Sound Energy Inc	Unsecured	400	5.685%	A2	A-	06/15/54	+120
83	06/05/24	NEE	NextEra Energy Capital Holdings Inc	Pref/Hybrid	1,200	6.750%	Baa2	BBB	06/15/54	+246
84	06/05/24	DUK	Duke Energy Corp	Unsecured	750	5.450%	Baa2	BBB	06/15/34	+118
85	06/05/24	DUK	Duke Energy Corp	Unsecured	750	5.800%	Baa2	BBB	06/15/54	+140
86	06/05/24	AES	AES Andes SA	Pref/Hybrid	530	8.150%	Ba1	BB	06/10/55	+384
87	06/10/24	EMACN	EUSHI Finance Inc	Pref/Hybrid	500	7.625%	Ba1	BB+	12/15/54	+314
88	06/05/24	PNW	Pinnacle West Capital Corp	Unsecured	350	FRN	Baa2	BBB	06/10/26	+82
89	06/17/24	AEP	American Electric Power Co.	Pref/Hybrid	400	7.050%	Baa3	BBB-	12/15/54	+275
90	06/17/24	AEP	American Electric Power Co.	Pref/Hybrid	600	6.950%	Baa3	BBB-	12/15/54	+268
91	06/17/24	ONCRTX	Oncor Electric Delivery	Secured	750	5.550%	A2	A+	06/15/54	+115
92	06/17/24	AEE	Ameren Illinois Company	Secured	625	5.550%	A1	A	07/01/54	+115
93	06/17/24	NI	NiSource Inc	Unsecured	600	5.200%	Baa2	BBB+	07/01/29	+95
94	06/17/24	CNP	CenterPoint Energy Resources Corp	Unsecured	400	5.400%	A3	BBB+	07/01/34	+115
95	06/24/24	HASI	Hannon Armstrong Sustainable Infrastructure Capital Ir	Unsecured	700	6.375%	Baa3	BB+	07/01/34	+225
96	06/25/24	EIX	Edison International	Unsecured	500	5.450%	Baa2	BBB-	06/15/29	+120
97	07/15/24	NGGLN	The Brooklyn Union Gas Co (Reopening)	Unsecured	150	6.388%	Baa2	BBB+	09/15/33	+167
98	07/15/24	NGGLN	The Brooklyn Union Gas Co	Unsecured	450	6.415%	Baa2	BBB+	07/18/54	+195
99	**07/29/24**	**CMS**	**Consumers Energy Co**	**Secured**	**700**	**4.700%**	**A1**	**A**	**01/15/30**	**+68**
100	07/29/24	DTE	DTE Energy Co	Unsecured	1,200	4.950%	Baa2	BBB	7/1/2027	+80

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Recent Utility Corporate Bond Issuances

for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-31 (MRB-9)
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Witness: MRBleckman
Date: December 2024

Line No.	(a) Issue Date	(b) Ticker	(c) Issuer	(d) Type	(e) Amt ($mm)	(f) Coupon	(g) Ratings Moody's	(h) Ratings S&P	(i) Maturity	(j) Issue Spread (bp)
1	08/01/24	PEG	Public Service Electric & Gas	Secured	600	4.850%	A1	A	8/1/2034	+90
2	08/01/24	PEG	Public Service Electric & Gas	Secured	500	5.300%	A1	A	8/1/2054	+105
3	08/01/24	AGR	New York State Electric & Gas Corp	Unsecured	525	5.300%	Baa1	A-	8/15/2034	+135
4	08/06/24	ETR	Entergy Louisiana LLC	Secured	700	5.150%	A2	A	09/15/34	+130
5	08/06/24	PPL	PPL Capital Funding Inc	Unsecured	750	5.250%	Baa1	BBB+	09/01/34	+143
6	08/06/24	SR	Spire Missouri Inc	Secured	320	5.150%	A1	A	08/15/34	+130
7	08/06/24	ES	The Connecticut Light and Power Co	Secured	300	4.950%	A1	A+	08/15/34	+110
8	08/06/24	D	Virginia Electric and Power Co	Unsecured	600	5.050%	A2	BBB+	08/15/34	+120
9	08/06/24	D	Virginia Electric and Power Co	Unsecured	600	5.550%	A2	BBB+	08/15/54	+140
10	08/07/24	IDA	Idaho Power Co	Secured	300	5.200%	A2	A-	08/15/34	+125
11	08/07/24	FTSCN	Tucson Electric Power Co	Unsecured	400	5.200%	A3	A-	09/15/34	+128
12	08/08/24	WTRG	Essential Utilities Inc	Unsecured	500	4.800%	Baa2	BBB+	08/15/27	+90
13	08/08/24	NRUC	National Rural Utilities Cooperative Finance Corp	Secured	350	5.000%	A1	A-	08/15/34	+110
14	08/08/24	OGS	One Gas Inc (Reopening)	Unsecured	250	5.100%	Aaa	AA+	04/01/29	+85
15	08/08/24	SRE	Southern California Gas Co	Secured	600	5.050%	Aa3	A+	09/01/34	+110
16	08/08/24	TVA	Tennessee Valley Authority	Unsecured	1,000	4.375%	Aaa	AA+	08/01/34	+48
17	08/12/24	DUK	Piedmont Natural Gas Co Inc	Secured	375	5.100%	A3	BBB+	02/15/35	+120
18	08/12/24	CNP	CenterPoint Energy	Pref/Hybrid	400	7.000%	Baa3	BBB-	02/15/55	+325
19	08/12/24	CNP	CenterPoint Energy	Pref/Hybrid	400	6.850%	Baa3	BBB-	02/15/55	+295
20	08/12/24	ETR	Entergy Texas Inc	Secured	350	5.550%	A3	A	09/15/54	+140
21	08/12/24	OGE	Oklahoma Gas and Electric Co (Reopening)	Secured	350	5.600%	A3	A-	04/01/53	+130
22	08/19/24	DUK	Duke Energy Corp	Pref/Hybrid	1,000	6.450%	Baa3	BBB-	09/01/54	+259
23	09/03/24	FE	FirstEnergy Transmission LLC	Unsecured	400	4.550%	Baa2	BBB+	01/15/30	+92
24	09/03/24	FE	FirstEnergy Transmission LLC	Unsecured	400	5.000%	Baa2	BBB+	01/15/35	+117
25	09/03/24	NI	NiSource Inc.	Pref/Hybrid	500	6.375%	Baa3	BBB-	03/31/55	+253
26	09/03/24	PCG	Pacific Gas and Electric Co	Secured	750	5.900%	Baa2	BBB	10/01/54	+180
27	09/03/24	PCG	Pacific Gas and Electric Co	Secured	1,000	FRN	Baa2	BBB	09/04/25	+95
28	09/03/24	EXC	PECO Energy Co	Secured	575	5.250%	Aa3	A	09/15/54	+112
29	09/03/24	EIX	Southern California Edison Co	Secured	500	4.400%	A2	A-	09/06/26	+55
30	09/03/24	SO	Southern Company Gas Capital Corp	Unsecured	450	4.950%	Baa1	A-	09/15/34	+115
31	09/04/24	LNT	Inerstate Power and Light	Unsecured	350	4.950%	Baa1	A-	09/30/34	+120
32	09/04/24	LNT	Inerstate Power and Light	Unsecured	300	5.450%	Baa1	A-	09/30/54	+140
33	09/04/24	SRE	Sempra	Pref/Hybrid	1,250	6.400%	Baa3	BBB-	10/01/54	+263
34	09/04/24	SO	The Southern Co	Unsecured	750	4.850%	Baa2	BBB+	03/15/35	+110
35	09/09/24	NRUC	National Rural Utilities	Unsecured	300	FRN	A2	A-	09/16/27	+100
36	09/09/24	NRUC	National Rural Utilities	Unsecured	550	4.120%	A2	A-	09/16/27	+58
37	09/09/24	NRUC	National Rural Utilities	Unsecured	500	5.150%	A2	A-	06/15/29	+73
38	09/09/24	PCG	PG&E Corporation	Pref/Hybrid	1,000	7.375%	Ba3	B	03/15/55	+388
39	09/09/24	WEC	Wisconsin Electric Power Co	Unsecured	300	4.600%	A2	A-	10/01/34	+90
40	09/09/24	WEC	Wisconsin Electric Power Co	Unsecured	300	5.050%	A2	A-	10/01/54	+108
41	09/16/24	ALACN	AltaGas Ltd	Pref/Hybrid	900	7.200%	NR	BB	10/15/54	+357
42	09/17/24	ATO	Atmos Energy Corp	Unsecured	650	5.000%	A1	A-	12/15/54	+108
43	09/26/24	NIAENE	Niagara Energy SAC	Unsecured	1,200	5.746%	Baa3	BBB-	10/03/34	+195
44	09/30/24	AEE	Union Electric Company d/b/a Ameren Missouri	Secured	450	5.125%	A2	A	03/15/55	+102
45	10/07/24	BRKHEC	Eastern Energy Gas Holdings	Unsecured	900	5.650%	Baa1	A-	10/15/54	+135

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Peer Company Commission Authorized Equity Ratios
for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-32 (MRB-10)
Page: 1 of 1
Witness: MRBleckman
Date: December 2024

(a) Line No.	(b) State	(c) Proxy Group Company	(d) Regulated Subsidiary	(e) Docket #	(f) Case Type	(g) Date Authorized	(h) Common Equity %
1	Tennessee	Atmos Energy Corporation	Atmos Energy Corporation	D-24-00006	Natural Gas	07/29/24	62.38%
2	Kentucky	Atmos Energy Corporation	Atmos Energy Corporation	C-2021-00214	Natural Gas	05/19/22	54.50%
3	Kansas	Atmos Energy Corporation	Atmos Energy Corporation	D-19-ATMG-525-RTS	Natural Gas	02/24/20	56.32%
4	Texas	Atmos Energy Corporation	Atmos Energy Corporation	D-GUD-10900	Natural Gas	04/21/20	60.12%
5	Colorado	Atmos Energy Corporation	Atmos Energy Corporation	D-22AL-0348G	Natural Gas	05/04/23	56.50%
6	Colorado	Black Hills Corporation	Black Hills Colorado Gas, Inc.	D-23AL-0231G	Natural Gas	03/24/24	50.98%
7	Iowa	Black Hills Corporation	Black Hills Iowa Gas Utility Company, LLC	D-RPU-2021-0002	Natural Gas	12/28/21	50.01%
8	Nebraska	Black Hills Corporation	Black Hills Nebraska Gas, LLC	D-NG-109	Natural Gas	01/26/21	50.00%
9	Arkansas	Black Hills Corporation	Black Hills Energy Arkansas, Inc.	D-21-097-U	Natural Gas	10/10/22	45.00%
10	Wyoming	Black Hills Corporation	Cheyenne Light, Fuel and Power Company	D-20003-214-ER-22	Electric	12/13/22	52.00%
11	Arkansas	CenterPoint Energy, Inc.	CenterPoint Energy Resources Corp.	D-17-010-FR	Natural Gas	09/23/21	52.55%
12	Indiana	CenterPoint Energy, Inc.	Indiana Gas Company, Inc.	Ca-45468	Natural Gas	11/17/21	55.62%
13	Indiana	CenterPoint Energy, Inc.	Southern Indiana Gas and Electric Company	Ca-45447	Natural Gas	10/06/21	55.49%
14	Minnesota	CenterPoint Energy, Inc.	CenterPoint Energy Resources Corp.	D-G-008/GR-21-435	Natural Gas	08/18/22	51.00%
15	Texas	CenterPoint Energy, Inc.	CenterPoint Energy Resources Corp.	D-OSS-23-00015513	Natural Gas	06/26/24	60.61%
16	Texas	CenterPoint Energy, Inc.	CenterPoint Energy Houston Electric, LLC	D-49421	Electric	03/09/20	42.50%
17	Kentucky	NiSource Inc.	Columbia Gas of Kentucky	C-2021-00183	Natural Gas	12/28/21	52.64%
18	Maryland	NiSource Inc.	Columbia Gas of Maryland	C-9680	Natural Gas	11/17/22	52.97%
19	Ohio	NiSource Inc.	Columbia Gas of Ohio	C-21-0637-GA-AIR	Natural Gas	01/26/23	50.60%
20	Pennsylvania	NiSource Inc.	Columbia Gas of Pennsylvania	D-R-2020-3018835	Natural Gas	02/19/21	54.19%
21	Indiana	NiSource Inc.	Northern Indiana Public Service Company	Ca-45967	Natural Gas	07/31/24	58.51%
22	Oregon	Northwest Natural Gas Company	Northwest Natural Gas Company	D-UG-435	Natural Gas	10/24/22	50.00%
23	Oklahoma	ONE Gas, Inc.	Oklahoma Natural Gas Company	Ca-PUD202100063	Natural Gas	11/30/21	58.55%
24	Texas	ONE Gas, Inc.	Texas Gas Service Company, Inc.	D-OSS-23-00014399	Natural Gas	01/31/24	59.07%
25	Missouri	Spire Inc.	Spire Missouri Inc.	C-GR-2021-0108	Natural Gas	10/27/21	54.28%
26	Illinois	WEC Energy Group, Inc.	North Shore Gas Company	D-23-0068	Natural Gas	11/16/23	55.58%
27	Illinois	WEC Energy Group, Inc.	The Peoples Gas Light and Coke Company	D-23-0069	Natural Gas	11/16/23	52.33%
28	Wisconsin	WEC Energy Group, Inc.	Wisconsin Electric Power Company	D-5-UR-110	Electric	12/29/22	59.01%
29	Wisconsin	WEC Energy Group, Inc.	Wisconsin Gas LLC	D-5-UR-110	Natural Gas	12/29/22	54.52%
30	Wisconsin	WEC Energy Group, Inc.	Wisconsin Public Service Corporation	D-6690-UR-127	Natural Gas	12/22/22	53.79%
	Average Equity Ratio						**54.05%**

Source: Individual state commission electronic docket records search.

Selection Criteria:
1. Regulated subsidiary of the Company's ROE proxy group in Case No. U-21490
2. Rate order issued from January 1, 2020 through September 30, 2024.
3. Rate order available through online docket search that includes an authorized equity ratio
4. For each regulated subsidiary, latest authorized equity ratio for each state / jurisdiction.

Note: Excludes final orders received by in-state proxy DTE Energy as well as the Company.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
State Regulatory Evaluations
for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-33 (MRB-11)
Page: 1 of 1
Witness: MRBleckman
Date: December 2024

Line No.	(a) Tier	(b) State	(c) Company	(d) Equity Ratio	(e) ROE	(f) (d) x (e) Rate of Return
1	Tier 1A	Alabama	Alabama Power	55.00%	10.87%	5.98%
2	Tier 1B	Florida	FPL	60.00%	10.80%	6.48%
3		Georgia	Georgia Power	56.00%	10.50%	5.88%
4		Pennsylvania	UGI (PA)	54.02%	9.85%	5.32%
5	Tier 1C	Wisconsin	WEC	52.40%	10.16%	5.32%
6		North Carolina	Duke Energy	53.00%	9.95%	5.27%
7		Iowa	IPL (IA)	51.00%	9.65%	4.92%
8	Average	Michigan[1]	Consumers Energy	50.01%	9.90%	4.95%

Source: Columns (a)-(c): August 2024 S&P Global Market Intelligence Report - RRA Regulatory Focus - State Regulatory Evaluations - Energy.
Columns (d) & (e): Company materials, S&P Capital IQ, investor presentations, and credit rating reports.
Column (f): Column (d) times column (e).

[1]In August 2024, Michigan's state regulatory ranking was downgraded from Above Average Tier 1C to Average.

Equity Research

WELLS FARGO

Industry Update — December 8, 2023

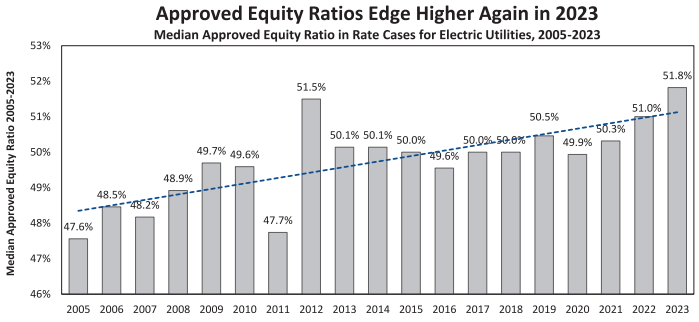
Utilities

Figure of the Week: Approved Equity Ratios, 2005-2023

Our Call

Figure of the Week

Click image to enlarge in HTML view.



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UW=Underweight: Total return on stock expected to lag the Overweight- and Equal Weight-rated stocks within the analyst's coverage universe over the next 12 months. SELL

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As of December 7, 2023
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44.0% of companies covered by Wells Fargo Securities, LLC Equity Research are rated Equal Weight.
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Wells Fargo Securities, LLC has provided investment banking services for 30.8% of its Equity Research Overweight-rated companies.
Wells Fargo Securities, LLC has provided investment banking services for 30.4% of its Equity Research Equal Weight-rated companies.
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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Cumulative Annual Interest Savings
for the Projected Year Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-35 (MRB-13)
Page: 1 of 1
Witness: MRBleckman
Date: December 2024

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)
Line			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
1	S&P Senior Secured Debt Credit Rating		BBB-	BBB	BBB	BBB	BBB+	BBB+	BBB+	A-	A	A	A	A	A	A	A	A	A	A	A	
2	Debt Issued - First Mortgage Bonds ($ millions)	A		$ -	$ 600	$ 500	$ 600	$ -	$ 725	$ 750	$ 500	$ 250	$ 450	$ 535	$ 1,900	$1,001	$ 1,661	$ 335	$ 800	$ 2,025	$ 1,300	$13,931
3	Interest Spread Differential vs. BBB-	B		1.31%	1.31%	1.31%	0.93%	0.99%	1.24%	0.82%	0.82%	0.53%	0.72%	0.61%	1.71%	0.85%	0.74%	0.56%	0.89%	1.32%	1.33%	
4	Annual Interest Savings ($ millions)	A x B		$ -	$ 8	$ 7	$ 6	$ -	$ 9	$ 6	$ 4	$ 1	$ 3	$ 3	$ 32	$ 8	$ 12	$ 2	$ 7	$ 27	$ 17	
5	Cumulative Annual Interest Savings ($ millions)			$ -	$ 8	$ 14	$ 20	$ 20	$ 29	$ 35	$ 39	$ 41	$ 44	$ 47	$ 80	$ 88	$ 100	$ 102	$ 109	$ 136	$ 153	**$ 153**
																					Annual savings repeats throughout entire life of the debt.	
6	BBB- Rating Issuance Spread	C	N/A	N/A	NMF	4.40%	2.17%	2.55%	2.47%	1.71%	1.69%	1.63%	1.83%	1.47%	2.64%	1.97%	2.01%	1.35%	2.29%	2.69%	2.43%	
7	Current Rating Issuance Spread (Line 2)	D	N/A	N/A	NMF	3.09%	1.24%	1.56%	1.23%	0.90%	0.87%	1.11%	1.11%	0.86%	0.93%	1.12%	1.27%	0.79%	1.39%	1.37%	1.09%	
8	Issuance Spread Differential vs. BBB-	C - D	-	-	-	1.31%	0.93%	0.99%	1.24%	0.82%	0.82%	0.53%	0.72%	0.61%	1.71%	0.85%	0.74%	0.56%	0.89%	1.32%	1.33%	

Source: All issuance spreads per the Barclays Bank Utility Deal listing. Initial data began during calendar year 2008. 2024 represents deals year to date as of October 25, 2024.
Line 3: Annual average fixed rate issuance spread versus BBB-, calculated in line 8.
Line 6: Annual average fixed rate BBB- issuance spread.
Line 7: Annual average fixed rate issuance spread for current ratings shown in Line 1.
Line 8 = Line 6 - Line 7.

S&P Global

RRA Regulatory Focus

RRA Regulatory Focus Quarterly Regulatory Evaluations

August 7, 2024

RRA State Regulatory Evaluations — Energy

Lillian Federico, Research Director, Energy

Contributors: Brian Collins, Jim Davis, Russell Ernst, Lisa Fontanella, Monica Hlinka, Jason Lehmann, Dan Lowrey

Editor: Majda Shabbir

For detailed data

Access RRA's State Regulatory Rankings July 2024.

Regulatory Research Associates, a group within S&P Global Commodity Insights, evaluates the regulatory climate for energy utilities in each of the jurisdictions within the 50 states and the District of Columbia — a total of 53 jurisdictions — on an ongoing basis. S&P Global Commodity Insights produces content for distribution on S&P Capital IQ Pro.

To learn more or to request a demo, visit spglobal.com/marketintelligence.

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Executive Summary

Introduction

RRA evaluates the regulatory climate for energy utilities in each of the jurisdictions RRA evaluates the regulatory climate for energy utilities in each of the jurisdictions within the 50 states and the District of Columbia — a total of 53 jurisdictions — on an ongoing basis. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by each jurisdiction's energy utilities.

Each evaluation is based upon consideration of the numerous factors affecting the regulatory process, including gubernatorial involvement, legislation and court activity, and may be adjusted as events occur that cause RRA to modify its view of the regulatory risk for a given jurisdiction.

RRA reviews the ranking of a particular jurisdiction on an ongoing basis as developments occur and then holistically reviews the rankings when preparing the quarterly comprehensive ranking reports. The issues considered are discussed in RRA Research Notes, Commission Profiles, Topical Special Reports and Rate Case analyses. RRA also considers information obtained from contacts with the commissioners and staff, as well as company and government personnel. The final evaluation is an indicator of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative and court actions.

It is important to note that RRA's rankings are from an investor perspective and are intended to provide insight into the relative risk associated with owning the securities of the jurisdictions in question. They are not an assessment of whether regulators are "doing a good job." In addition, the rankings look at not only the commission's actions but those taken by the jurisdiction's legislature, courts and chief executive, as well as the various stakeholders that intervene in the regulatory process.

About This Report

This report provides a discussion of recent changes in RRA's energy regulatory rankings, with details regarding the rationale for these changes. The report also identifies jurisdictions with ongoing proceedings or developing issues that have the potential to impact the relative regulatory risk for utilities operating within a given jurisdiction and, by extension, the ranking of that jurisdiction. The report also provides a discussion of key regulatory issues that impact the sector outlook as a whole. Finally, the report includes an overview of RRA's ranking methodology and the issues RRA examines in deriving the rankings.

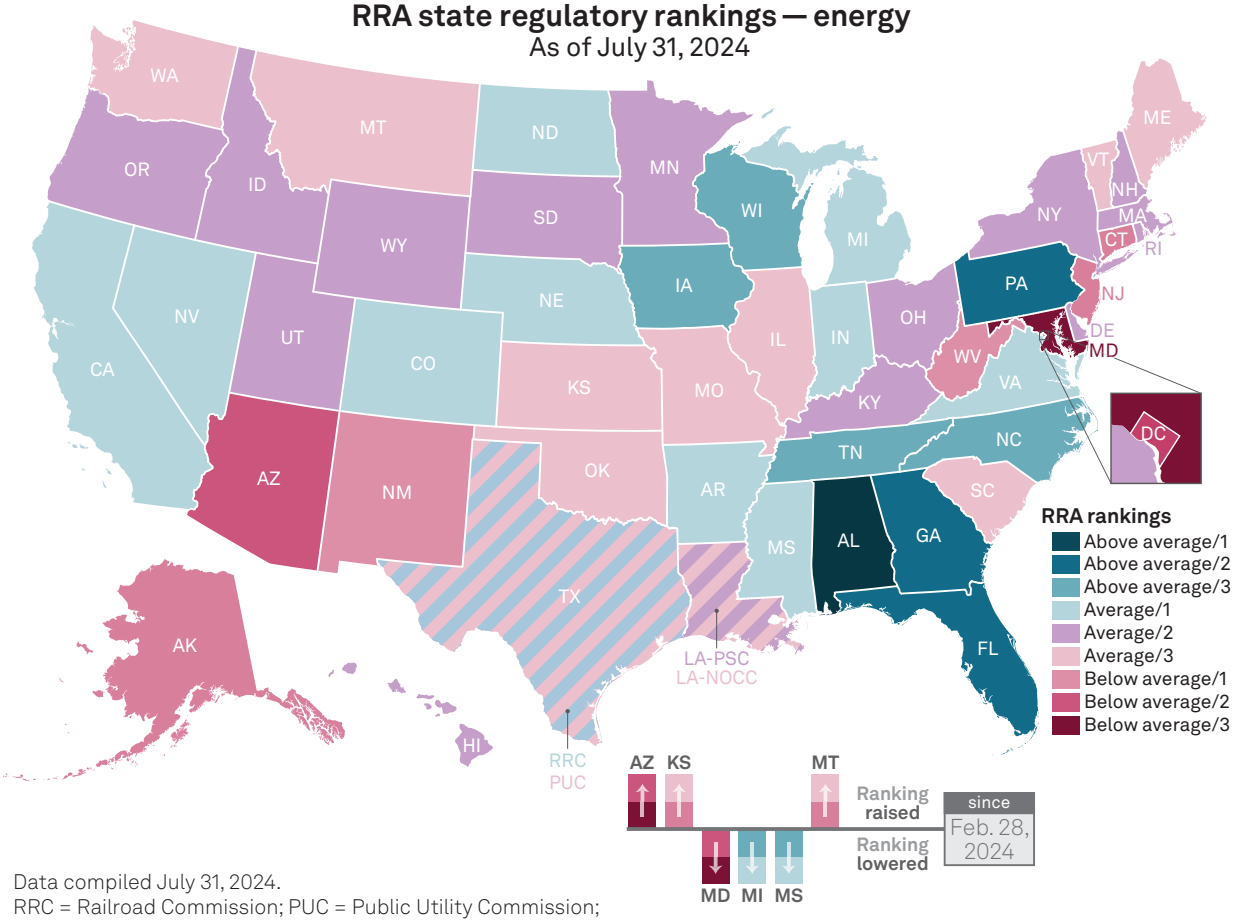
The Take

In light of recent and ongoing developments, Regulatory Research Associates has altered the regulatory rankings of six state-level jurisdictions under coverage and identified nine jurisdictions that bear watching, given recent commission, legislative, gubernatorial and/or court activity.

Developments continue to unfold on a variety of key issues across the regulated utility sector nationwide on an ongoing basis, including evolving public policy related to the energy transition, accelerated capital spending driven largely by programs to meet a variety of societal goals, and higher inflation and interest rates than the US had seen in the prior four decades.

State regulators will play a pivotal role in determining the direction and magnitude of these impacts on the financial performance of the utilities that fall under their purview. How the individual jurisdictions meet these challenges will continue to inform RRA's prospective comparative risk assessments.

RRA state regulatory rankings — energy
As of July 31, 2024



Data compiled July 31, 2024.
RRC = Railroad Commission; PUC = Public Utility Commission;
PSC = Public Service Commission; NOCC = New Orleans City Council.
Map credit: Joe Felizadio.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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Recent ranking changes

Following a comprehensive review of the current rankings conducted during July, RRA made six ranking changes. RRA is raising the ranking of **Arizona**, **Kansas** and **Montana**, while lowering the rankings of **Maryland**, **Michigan** and **Mississippi**. The reasons for these changes are discussed in the paragraphs that follow.

Recent rate case decisions issued by the **Arizona** Corporation Commission (ACC) have been relatively constructive. The commission's decision for Pinnacle West Capital Corp. subsidiary Arizona Public Service Co. earlier in 2024 in particular represents a marked improvement over a 2021 ACC ruling that incorporated one of the lowest equity return authorizations observed by RRA in the last 40 years. Several recent commission electric rate orders have also authorized the state's investor-owned utilities to implement a constructive system reliability benefit mechanism to recognize rate base additions between rate cases. Based on these developments, RRA upgraded its rating of the Arizona regulatory environment for energy utilities to Below Average/2 from Below Average/3.

RRA also raised the ranking of the **Kansas** regulatory climate to Average/3 from Below Average/1 to recognize the recent enactment of legislation that allows the use of plant-in-service accounting for electric utility infrastructure investments that are made between a utility's base rate proceedings. Prospectively, the utilities will be permitted to defer, for future recovery, 90% of the depreciation expense and rate of return associated with "qualifying electric plant" investments. The resulting regulatory asset balances, which are to accrue carrying charges at the utility's weighted average cost of capital and be amortized over a 20-year period once included in rates, are to be adjusted to reflect any prudence disallowances ordered by the Kansas Corporation Commission. The new law is expected to mitigate the impact of regulatory lag for the electric utilities operating in the state and improve their prospects for earning their authorized returns.

Additionally, RRA also raised the ranking of the **Montana** regulatory climate to Average/3 from Below Average/1, in recognition of the constructive aspects of recent electric and gas rate case decisions issued by the Montana Public Service Commission for NorthWestern Energy Corp. In these proceedings, the Montana PSC authorized returns on equity that exceeded nationwide averages approved in settled cases for both electric and gas utilities. The authorized electric return on equity (ROE) exceeded nationwide average for all electric cases, while the authorized gas ROE approximated the nationwide average. In addition, the orders allow NorthWestern Energy to defer, for later rate recovery, incremental wildfire expenses that are capped annually. Given that the Montana PSC relies upon historical test periods and average rate base valuations that tend to exacerbate regulatory lag and that the magnitude of wildfire-associated costs appears to be accelerating rapidly for many utilities across the US Northwest, RRA views the ability of NorthWestern Energy to defer its wildfire expense for future recovery as constructive from an investor viewpoint. In pending rate cases before the Montana PSC, NorthWestern Energy is seeking a new balancing account for wildfire management costs, which may help to further reduce regulatory lag as it pertains to investments in wildfire mitigation programs and insurance costs.

By contrast, the **Maryland** regulatory climate has become increasing risky from an investor standpoint since the governor changed in January 2023. The incoming governor, Democrat Wes Moore, quickly removed three members of the Maryland Public Service Commission from office, including the chairman. The incoming chair, who has now been in the position for a little over a year, is a former attorney in the Office of People's Counsel (OPC). In the wake of this change, the OPC has become more vocal and taken a more contentious stance in regulatory proceedings.

RRA state regulatory evaluations

State-by-state listing — Energy

Jurisdiction	Ranking	Jurisdiction	Ranking	Jurisdiction	Ranking
Alabama	Above Average/1	Louisiana — NOCC	Average/3	Ohio	Average/2
Alaska	Below Average/1	Louisiana — PSC	Average/2	Oklahoma	Average/3
Arizona*	Below Average/2	Maine	Average/3	Oregon	Average/2
Arkansas	Average/1	Maryland**	Below Average/3	Pennsylvania	Above Average/2
California	Average/1	Massachusetts	Average/2	Rhode Island	Average/2
Colorado	Average/1	Michigan**	Average/1	South Carolina	Average/3
Connecticut	Below Average/2	Minnesota	Average/2	South Dakota	Average/2
Delaware	Average/2	Mississippi**	Average/1	Tennessee	Above Average/3
District of Columbia	Below Average/2	Missouri	Average/3	Texas — PUC	Average/3
Florida	Above Average/2	Montana*	Average/3	Texas — RRC	Average/1
Georgia	Above Average/2	Nebraska	Average/1	Utah	Average/2
Hawaii	Average/2	Nevada	Average/1	Vermont	Average/3
Idaho	Average/2	New Hampshire	Average/2	Virginia	Average/1
Illinois	Average/3	New Jersey	Below Average/1	Washington	Average/3
Indiana	Average/1	New Mexico	Below Average/1	West Virginia	Below Average/1
Iowa	Above Average/3	New York	Average/2	Wisconsin	Above Average/3
Kansas*	Average/3	North Carolina	Above Average/3	Wyoming	Average/2
Kentucky	Average/2	North Dakota	Average/1		

Data compiled July 31, 2024.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission.
* Ranking raised since Feb. 28, 2024.
** Ranking lowered since Feb. 28, 2024
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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One of the new commissioners is a former state legislator, while the other is an attorney who has represented various stakeholder interests before state and federal regulators. Since these changes, the commission's decisions have become more restrictive from an investor viewpoint, culminating in a June 2024 decision rejecting a multiyear rate plan proposed by Exelon Corp. subsidiary Potomac Electric Power Co., and raising questions regarding future use of that framework in the state.

Contemporaneous with this decision, Anthony O'Donnell, a long-time commissioner who did not participate in issuing the order, resigned, creating uncertainty with respect to the future makeup of the commission and opening up the prospect for another more consumer-oriented replacement.

In light of these developments, RRA is again lowering the ranking for Maryland regulation, this time to Below Average/3 from Below Average/2. This is the third reduction in the jurisdiction's ranking since mid-2023.

RRA is also lowering the ranking of **Michigan** regulation — to Average/1 from Above Average/3. While the jurisdiction remains more constructive than average from an investor viewpoint, the outcomes of recent rate proceedings have been mixed and could indicate a tightening in the regulatory climate.

RRA had placed the state on watch following a 2022 rate case decision in which the Michigan Public Service Commission authorized DTE Energy Inc. subsidiary DTE Electric Co. (DTE-E) an increase in rates that was less than 10% of that requested. At the time, RRA viewed the decision to be an anomaly.

The company filed a new rate case less than three months later, asserting that existing rates and projected electricity sales could not sustain its major capital investment program. Even though the ultimate outcome of this case was more constructive, DTE-E filed a third case within four months of the decision (on March 28, 2024), which is pending. The filing has met significant resistance from consumer groups who characterize the request as "absurd in both the astounding dollars and obnoxious timing," implying that this case will be more contentious than usual.

In a July 2 fully litigated electric rate decision for American Electric Power Co. subsidiary Indiana Michigan Power Co. (IMP), the commission authorized the company a rate increase that was about half of what IMP had requested. Rate of return and expense items accounted for most of the revenue requirement differences; among the items disallowed by the PSC were costs associated with employee incentive compensation and enhanced customer service technology, as well as a company-proposed inflation adjustment. Similar to the DTE-E proceedings, the commission voted to keep IMP's ROE unchanged despite recent increases in interest rates.

While a recently decided (July 23) gas rate case for CMS Energy subsidiary Consumers Energy Co. (CE) was settled rather than fully litigated, the stipulated revenue requirement increase was also less than half of that requested by CE and the authorized ROE remained unchanged from the last case.

While the approved ROEs for DTE, IMP and CE remain above prevailing industry averages, they compare less favorably to these averages, which have risen, albeit modestly, in recent periods.

Against this backdrop, six major utility rate cases are pending, including the aforementioned DTE-E electric rate case, most of which are driven at least in part by capital spending programs intended to comply with state reliability and energy transition policies; outcomes consistent with the above recently completed cases could render it difficult for the companies to continue to support these initiatives.

Also of concern, the electric utilities have been subject to more intensive scrutiny since extensive outages ensued in August 2021, following a major storm.

The **Mississippi** energy utilities continue to operate under streamlined, formulaic alternative rate plans in lieu of general base rate cases. The plans provide for annual rate adjustments and reflect timely recognition of new investments and fluctuations in operating costs. When specified, authorized equity returns as calculated under the plans have generally exceeded prevailing industry averages. However, RRA is lowering the rating of Mississippi regulation at this time to Average/1 from Above Average/3. The change partially reflects the relative inexperience of the three new commissioners that were seated at the Mississippi Public Service Commission earlier in 2024 but is also necessary to maintain a normalized balance in RRA's relative ranking of US regulatory bodies.

In conjunction with the prior review conducted during February 2024, RRA changed the ranking of **Virginia** regulation, raising it to Average/1 from Average/2, to reflect the removal of significant regulatory uncertainty with the election of two individuals to fill long-standing vacancies on the Virginia State Corporation Commission.

RRA also noted that in December 2023, RRA had lowered the ranking of the **Illinois** regulatory climate to Average/3 from Average/2 to reflect the impact of adverse rulings issued for Exelon Corp. subsidiary Commonwealth Edison Co. and Ameren Corp. subsidiary Ameren Illinois Co. in their respective multiyear grid and rate plan proceedings.

Jurisdictions to watch

In addition to the jurisdictions discussed above, where RRA has observed a shift in the regulatory climate, there are nine states where current trends and expected near-term developments could signal a shift in the level of regulatory risk for investors. Even though RRA recently revised the ranking of the regulatory climates in Arizona, Connecticut and Illinois, these jurisdictions continue to bear monitoring.

While RRA raised the ranking of **Arizona** regulation as part of its current review (discussed in the preceding section of this report), ongoing issues merit continued scrutiny, including the ACC's actions earlier in 2024 to reexamine certain long-standing rules, raising the prospect of a rollback of the commission's renewable energy requirements, among other things. While some commissioners have asserted that the rules have unnecessarily burdened ratepayers, the state's major electric utilities are continuing to transition toward more renewable heavy generation portfolios, and a disruption in the policy could have unforeseen consequences for the companies. In addition, three of the ACC's five commissioner seats are up for election this year, as are the governor and both chambers of the Arizona legislature. Changes in the makeup of these branches of state government could result in significant commission policy changes.

After lowering the ranking of **Connecticut** regulation in August 2023, RRA has continued to closely monitor the jurisdiction, which continues to be one of the most challenging in the US. Changes are currently underway to the makeup of the Connecticut Public Utilities Regulatory Authority (PURA), which under state law can be comprised of up to five members. Gov. Ned Lamont (Democrat) recently announced that long-standing commissioner John Betkoski (Democrat), who is serving beyond the end of his term, will be stepping down at the end of 2024. At the same time, Lamont announced the nomination of former state legislator and utility government affairs employee, David Arconti, Jr, (Democrat) as a new PURA commissioner to begin serving Aug. 5, subject to confirmation by the General Assembly in 2025. The other current members of the PURA, Chair Marissa Gillett (Democrat) and Michael Caron (Republican) continue to serve beyond the expiration of their terms.

Recent rate case decisions have demonstrated significant constriction in the regulatory climate and have created additional uncertainty surrounding the overall tenor of regulatory policy in the state. An appeal is ongoing of a 2023 rate case decision, in which the PURA authorized Avangrid Inc. subsidiary The United Illuminating Co. an 8.63% that reflected a 47-basis-point penalty for management and operational performance issues. Even without the penalty, the implied base ROE of 9.10% was among the lowest approved for an energy utility in recent years.

There are two gas rate cases pending for other Avangrid subsidiaries, as well as a legislatively mandated alternative ratemaking proceeding where the PURA is reviewing rules governing multiyear rate plans, earnings-sharing mechanisms, revenue decoupling and potential performance-based ratemaking measures for the electric utilities.

Even though RRA recently lowered the ranking of Illinois to reflect restrictive **Illinois** Commerce Commission (ICC) rate case rulings issued in late 2023, the state continues to bear watching, as Exelon Corp. subsidiary Commonwealth Edison Co. (ComEd) and Ameren Corp. subsidiary Ameren Illinois Co. have revised grid plan filings, pending ICC consideration. The commission is expected to render decisions on the proposals in December.

Further, the ICC's determinations in gas proceedings in late 2023 raise the possibility of the commission continuing to disregard the recommendations put forth by its own internal experts to the detriment of the state's utilities, raising the potential for further constriction in the regulatory climate. Three of the five commissioners are relatively new, having been in office for about a year; so, even though one of the "new" commissioners has served before, the commissioners are evolving in terms of how they work together. In addition to the revised grid plan requests, there is one pending rate case for a relatively small gas utility.

Iowa remains a jurisdiction to watch, considering the Iowa Utilities Commission's (IUC) actions in recent advanced ratemaking decisions regarding new renewable generation projects. In October 2023, the IUC made modifications to a settlement for Alliant Energy Corp. subsidiary Interstate Power and Light Co. (IPL), including a reduction in the authorized ROE for new solar generation; the settlement had specified a 10.75% ROE, but the IUC authorized a 10.25% ROE. While being higher than prevailing industry averages, the modified ROE is below previously approved ROEs for these types of facilities.

Prior to that, in April 2023, the IUC approved Berkshire Hathaway Inc. subsidiary MidAmerican Energy Co.'s Wind PRIME project but rejected a settlement regarding the associated advance ratemaking principles, leaving the ROE to be determined in a future rate case. On rehearing, the parties reached a revised agreement that the IUC approved without modification in December 2023, including an authorization of a 10.75% ROE for the project. However, in the ruling, one commissioner expressed concerns about approving a "premium ROE" within mature renewable energy markets, potentially indicating an eventual conclusion to the practice of approving premium ROEs for these types of investments.

RRA state regulatory evaluations — Energy*

(By category, jurisdictions to watch highlighted)

Above Average/1	Above Average/2	Above Average/3	Average/1	Average/2	Average/3	Below Average/1	Below Average/2	Below Average/3
Alabama	Florida	Iowa	Arkansas	Delaware	Illinois	Alaska	Arizona	Maryland
	Georgia	North Carolina	California	Hawaii	Kansas	New Jersey	Connecticut	
	Pennsylvania	Tennessee	Colorado	Idaho	Louisiana — NOCC	New Mexico	Dist. of Columbia	
		Wisconsin	Indiana	Kentucky	Maine	West Virginia		
			Michigan	Louisiana — PSC	Missouri	New Mexico		
			Mississippi	Massachusetts	Montana	West Virginia		
			Nebraska	Minnesota	Oklahoma			
			Nevada	New Hampshire	South Carolina			
			North Dakota	New York	Texas — PUC			
			Texas — RRC	Ohio	Vermont			
			Virginia	Oregon	Washington			
				Rhode Island				
				South Dakota				
				Utah				
				Wyoming				

Data compiled July 31, 2024.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission.
*Within a given subcategory, states are listed in alphabetical order, not by relative ranking.
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It is noteworthy that two of the three current commissioners are relatively new to the IUC, having joined in May 2023. Consequently, two pending rate cases may face some uncertainty. IPL is in the midst of its first major electric and gas base rate case since 2019; hearings are underway after certain parties signed a nonunanimous settlement. Black Hills Iowa Gas Utility Co. LLC also has a case in progress — its first in about three years.

Kentucky continues to bear watching, as the Kentucky Public Service Commission's pattern of imposing modifications to rate case settlements over the past couple of years remains a cause for concern. The most recent rate case decision for a large utility occurred in January 2024, when the PSC authorized American Electric Power Co. Inc. subsidiary Kentucky Power Co. a rate increase that was meaningfully below the stipulated hike the parties had agreed to in a settlement; the revenue requirement difference stemmed largely from an adverse ruling on transmission-related cost recovery. The commission also rejected a settlement provision that called for the company to implement a distribution reliability rider.

Separately, legislation enacted earlier in 2023 prohibits the Kentucky PSC from approving requests to retire fossil fuel-fired facilities, unless the utility can demonstrate that the plant's retirement would not adversely impact ratepayers or the region's electric grid reliability. The Kentucky PSC recently approved one such proposal — by PPL Corp. subsidiaries Louisville Gas and Electric Co. and Kentucky Utilities Co. — that will result in meaningful changes to the composition of the companies' generation portfolios.

On a constructive note, a separate bill signed in 2023 allows the electric utilities to securitize certain costs associated with retired generation facilities and storm restoration efforts. The PSC recently approved Kentucky Power's securitization request. Even so, it is unclear how the commission will approach future requests.

The term of former Chairman Kent Chandler, a Democrat, expired June 30, and he left the commission instead of seeking reappointment. Gov. Andy Beshear, a Democrat, has not named a replacement. This development adds uncertainty to the state's regulatory climate at the same time that investors are seeking clarity regarding the commission's stance on a variety of regulatory matters.

New Jersey bears watching at this juncture, as Public Service Enterprise Group Inc. subsidiary Public Service Electric and Gas Co. — the largest utility in the state — is in the midst of its first combination electric and gas base rate case in several years. Proceedings are also underway for two of the major gas local distribution companies (LDCs), New Jersey Resources Inc. subsidiary New Jersey Natural Gas Co. and Elizabethtown Gas Co., with Elizabethtown Gas affiliate South Jersey Gas Co. expected to file a case by the end of 2024. The latter two LDCs are held by South Jersey Industries Inc., which is owned by Infrastructure Investments Fund US Holding 2 LP.

With these cases, as well as various energy transition proceedings under way, including a review of the state's Energy Master Plan, the New Jersey Board of Public Utilities is operating with one vacancy and three new members who took office in 2023, including the recently named president.

Due to uncertainty caused by changes in the composition of the **Oklahoma** Corporation Commission (OCC), the combative stance taken in recent proceedings by one of the long-time OCC members and the commission's decision to depart from customary practice and require significant changes to a rate case settlement, RRA lowered its ranking of Oklahoma regulation in November 2023. RRA continues to consider Oklahoma a state to watch, as two of the major energy utilities in the state have substantial rate requests pending.

The regulatory climate in **Texas**, as it pertains to the electric utilities under the purview of the Public Utility Commission of Texas, continues to bear watching. The regulatory framework in Texas and the PUC has been the focus of intense scrutiny, since a 2021 severe weather event caused widespread multiday outages and price spikes within Electric Reliability Council of Texas (ERCOT). While various proceedings are ongoing to transform the framework, the dramatic controversies that arose following that event have largely abated. Recent wildfire and severe storm activity could cause renewed focus on the utilities and the market structure in Texas.

Gov. Greg Abbott's reelection in 2022 provided a measure of stability, though there continues to be turnover at the PUC. One commissioner is serving beyond the end of term that expired in 2021, and both the PUC chair and a newly appointed commissioner are serving pending confirmation by the Senate when the legislature reconvenes in 2025.

Against this backdrop, both CenterPoint Energy Inc. subsidiary CenterPoint Energy Houston Electric Co. and American Electric Power Co. subsidiary AEP Texas Inc. filed rate cases in the first quarter of 2024 and certain intervenors took restrictive positions in their direct testimony in these cases. While a settlement was reached in the AEP Texas case, CenterPoint has filed a motion to withdraw its case in light of ongoing controversy surrounding the company's response to outages caused by Hurricane Beryl and the PUC has initiated a review of CenterPoint's actions during and following the storm.

Several of the utilities have also filed system resiliency proposals in accordance with 2023 legislation; these proceedings may prove challenging in light of the recent weather-related events.

The **Wyoming** regulatory climate bears watching, as the legal and legislative ramifications of a contentious electric general rate case decision for Berkshire Hathaway Inc. subsidiary PacifiCorp continue to play out. The utility has already filed a federal suit against the Wyoming Public Service Commission's order issued in January, arguing that the commission failed to account for the costs of maintaining reserve capacity, as mandated by the Federal Energy Regulatory Commission. PacifiCorp also plans to pursue action in state court, although the company has not specified when it plans to file.

In addition, multiple pieces of legislation enacted during the 2024 session addressed several issues that arose in recent commission proceedings, including recovery of costs associated with neighboring states' environmental policies and cost-tracking mechanisms to allow utilities to recover changes in certain electric supply costs between rate cases.

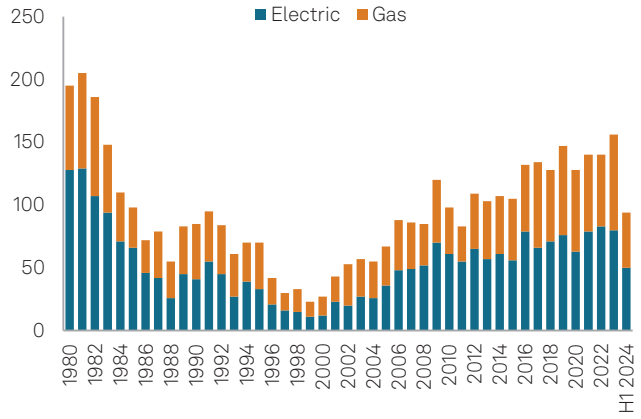
Outlook

Developments continue to unfold on a variety of key issues across the regulated utility sector nationwide. Accelerating capital spending to address a variety of public policy goals, inflation and rising interest rates present challenges for utilities and regulators and are driving an active rate case agenda across the US.

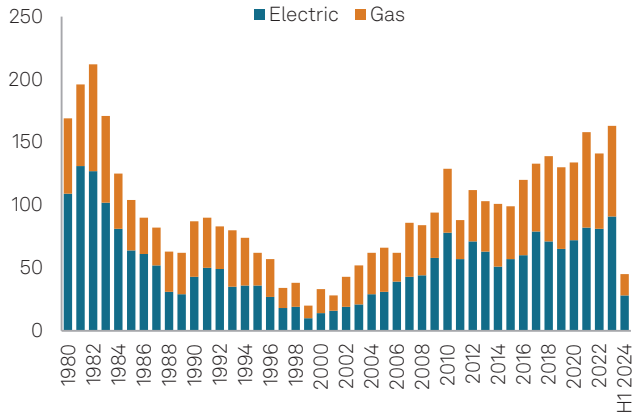
There were 164 electric and gas rate cases decided for the US investor-owned energy utilities in RRA's coverage universe during 2023, with an aggregate $9.3 billion of rate increases approved in those cases. During the first half of 2024, 45 cases were decided, netting $2.3 billion in rate increases.

The covered companies filed 156 new electric and gas rate cases, including limited-issue rider proceedings in 2023, with 94 filed in the first half of 2024. The combined rate increases requested in the 2023 cases aggregated to more than $18.1 billion, while those sought in the 2024 filings added up to almost $12.3 billion.

Major rate cases fillings, 1980-2022



Major rate cases decisions, 1980-2022



Data compiled July 24, 2024.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights
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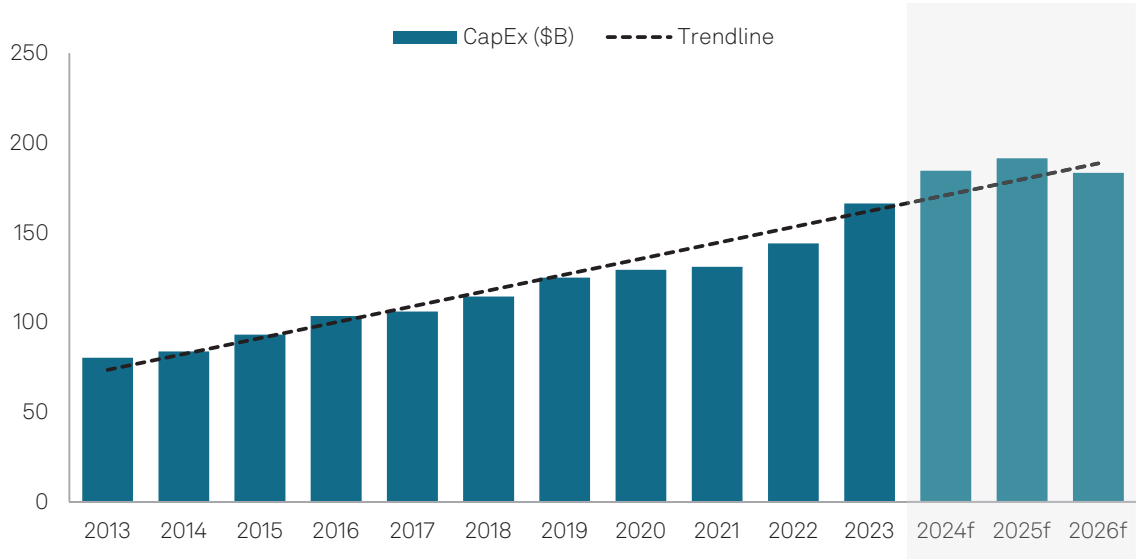
RRA anticipates this trend of robust rate case activity will persist for the foreseeable future, driven by continued expansion in capital spending.

Capital spending has risen steadily since 2006, when the energy utilities included in RRA's sample of the publicly traded US energy utilities reported total actual capital spending of about $52 billion; actual capital spending for the group came in at $166 billion in 2023.

According to data gathered by RRA in March, spending is expected to expand to $184 billion in 2024, increase to $191 billion in 2025 and moderate to $183 billion in 2026, bringing the total for the forecast period (2024–2026) to $559 billion.

Energy actual and estimated capital spending



Data compiled March 27, 2024.
Capex = capital expenditure; f = forecast.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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The impacts of severe weather events, such as hurricanes, winter storms and wildfires, continue to play a more prominent role in utility financial outlooks and are contributing to the active rate case agenda.

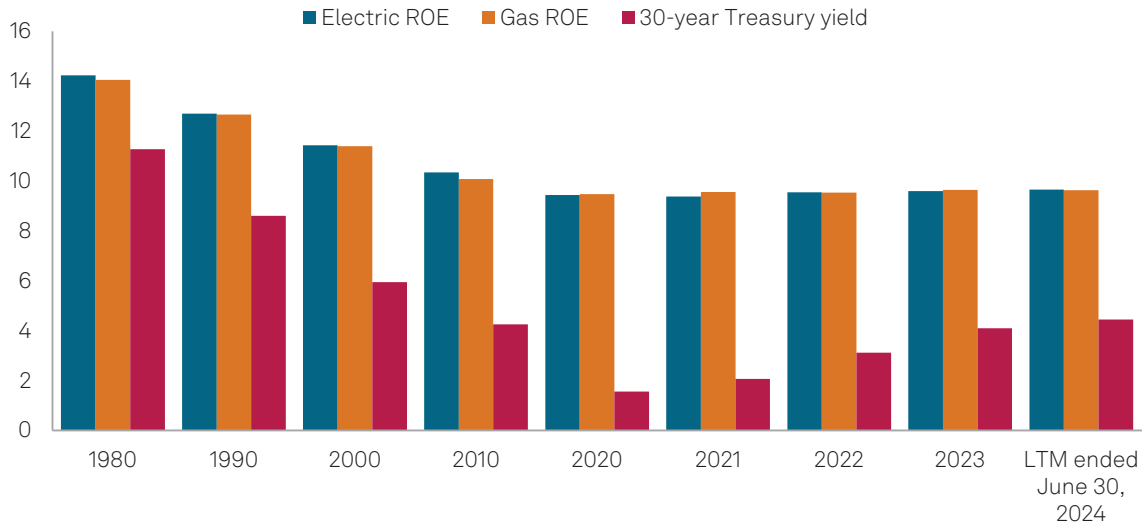
The need to recover the related costs, together with the previously listed factors, will continue to put upward pressure on rates, exacerbating prevailing concerns about ratepayer impacts and affordability, and rendering it challenging for companies to reflect higher financing costs in their authorized returns.

The spread between average authorized ROEs and US Treasury bond yield contracted to roughly 550 basis points in 2023 from almost 800 basis points in 2020. The spread has continued to shrink in 2024, such that for the 12 months ended June 30, 2024, the spread approximated 520 basis points.

Still, the spread remains higher than it was during previous periods. For example, during the early 1980s — another time when the industry faced aggressive capital spending and persistently high levels of inflation and interest rates — the spread between Treasury yields and authorized ROEs was less than 300 basis points.

Average US utility authorized ROEs; 30-year US Treasury bond yields

Select calendar years, 1980-2023, LTM June 30, 2024



Data compiled July 24, 2024.
ROE=return on equity; LTM = last 12 months.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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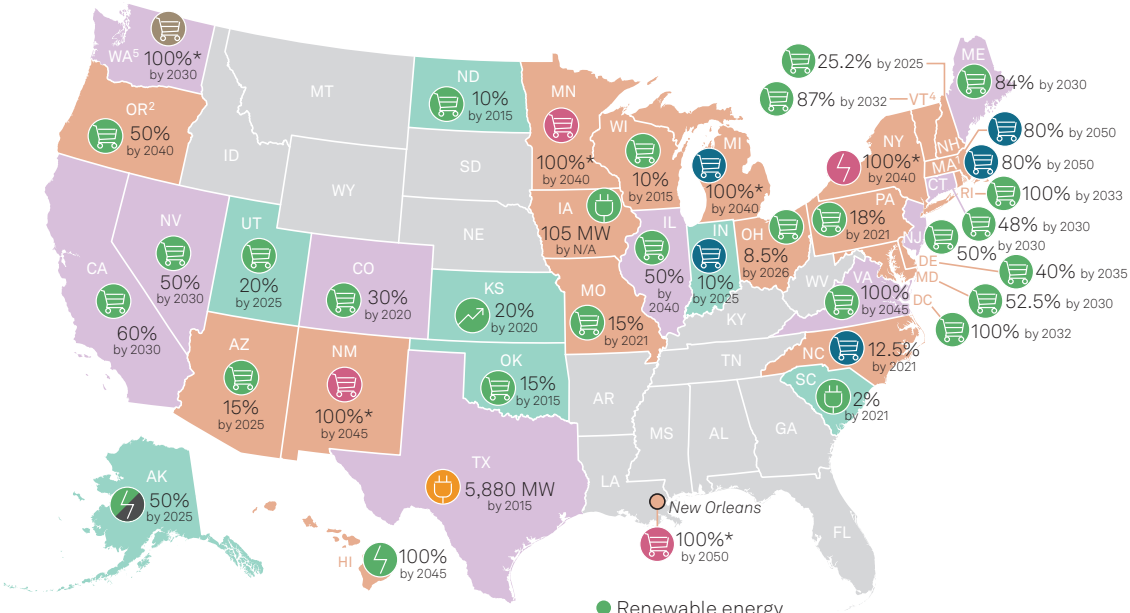
The evolving energy transition presents unique challenges for the electric and gas utility sector, but also offers potential for growth. Much of the evolution has come via state legislative initiatives and energy issues continue to be a focus in the current legislative session.

Energy issues will be a factor in the 2024 US presidential election, as well as state level elections, with gubernatorial elections scheduled in 11 states, legislative elections in 44 states and utility commissioners on the ballots in 10 states.

State renewable and clean energy standards and goals



Mandatory renewable, clean energy standards
Nonbinding energy goals
Additional goals on top of a mandatory standard

Renewable energy
Clean energy
Carbon-free
Greenhouse gas neutral
Alternative energy
Solar energy

Electric generation
Installed capacity
Peak demand
Retail sales

California	100%	2045	Illinois	100%	2050	New Jersey	100%	2035	Washington	100%	2045
Colorado	100%[3]	2050	Maine	100%	2050	Texas	10,000 MW	2025			
Connecticut	100%	2040	Nevada	100%	2050	Virginia	100%	2040			

Data compiled July 29, 2024.
Targets indicate the final requirement and do not include interim steps. The data also does not include voluntary targets adopted by utilities, corporations, public power districts, etc.
* There are interim steps within the renewable portfolio standard that allow for a target to be met with renewable energy resources; however, the carbon-free target is the ultimate target resource policy.
[1] Massachusetts currently has in place a Clean Energy Standard and a separate Renewable Portfolio Standard. The 40% renewables by 2030 standard does not have a stated expiration date; the standard is to increase by 1% each year and will reach 100% renewable energy by 2090. The clean energy standard requires 80% clean energy by 2050.
[2] The state's clean energy targets legislation requires retail electricity providers to reduce emissions by 100% by 2040; while it is a separate policy, it is complementary and works in tandem with the renewable portfolio standard.
[3] The goal is in place for a retail utility that provides service to more than 500,000 customers, such as Xcel Energy, or any utility that decides to opt in.
[4] Legislation enacted in June 2024 modifes and increases the state's renewable portfolio standard to 100% retail sales by 2030 or 2035, depending on the size of the provider. The state's largest utility, Green Mountain Power, must reach the 100% target by 2030.
[5] Washington has an additional 15% renewable energy standard in place. The state's 2045 target of 100% renewable and nonemitting resources is a mandate and not a voluntary goal.
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These factors raise the overall level of uncertainty, or investor risk, across the sector. State regulators will play a pivotal role in determining the direction and magnitude of these impacts on the financial performance of the utilities that fall under their purview. How the individual jurisdictions meet these challenges will continue to inform RRA's prospective comparative risk assessments.

RRA's rankings process

RRA ranks the regulatory climate in a total of 53 state-level jurisdictions, including the District of Columbia and the New Orleans City Council, and two regulatory bodies in Texas — the Public Utility Commission of Texas regulates electric utilities, while the Railroad Commission of Texas regulates gas local distribution companies.

RRA maintains three principal ranking categories — Above Average, Average and Below Average — with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint and Below Average indicating a less constructive, higher-risk regulatory climate.

The numbers 1, 2 and 3 within each principal ranking category indicate relative position. The designation 1 indicates a stronger or more constructive ranking from an investor viewpoint; 2, a midrange rating; and 3, a less constructive rating.

Hence, if you were to assign numeric values to each of the nine resulting categories, with a "1" being the most constructive from an investor viewpoint and a "9" being the least constructive from an investor viewpoint, then Above Average/1 would be a "1" and Below Average/3 would be a "9."

Methodology

RRA designed the rankings to reflect the interest of equity and fixed-income investors across more than 30 individual metrics. The metrics are scored based on the covering analysts' subjective judgment and then aggregated to create a single score for each state, with certain categories, such as the state's history with respect to authorized equity returns, practice with respect to rate case test years and presence, or lack of alternative ratemaking provisions, weighted more heavily than others.

RRA then ranks the states from lowest to highest and distribute them among the nine categories to create an approximate normal distribution. The team then reviews the distribution and may adjust individual state rankings based on the covering analysts' recommendations, subject to review by a designated panel of senior analysts.

The variables that RRA considers in determining each state's ranking are largely the broad issues detailed in state commission profiles and those that arise in the context of rate cases, generic policy proceedings, legislation and gubernatorial directives.

RRA's articles and reports on these issues are accessible through the S&P Capital IQ Pro platform, as are the jurisdictional commission profiles and RRA's database of major investor-owned utility rate case decisions going back to 1980.

RRA State Regulatory Evaluations*

Above Average/1	Average/1	Below Average/1
Alabama	Arkansas	Alaska
	California	New Mexico
	Colorado	New Jersey
	Michigan	West Virginia
	Mississippi	
	Indiana	
	Nebraska	
	Nevada	
	North Dakota	
	Texas — RRC	
	Virginia	
Above Average/2	**Average/2**	**Below Average/2**
Florida	Delaware	Arizona
Georgia	Hawaii	Connecticut
Pennsylvania	Idaho	District of Columbia
	Kentucky	
	Louisiana — PSC	
	Massachusetts	
	Minnesota	
	New York	
	New Hampshire	
	Ohio	
	Oregon	
	Rhode Island	
	South Dakota	
	Utah	
	Wyoming	
Above Average/3	**Average/3**	**Below Average/3**
Iowa	Illinois	Maryland
North Carolina	Louisiana — NOCC	
Tennessee	Kansas	
Wisconsin	Maine	
	Missouri	
	Montana	
	Oklahoma	
	South Carolina	
	Texas — PUC	
	Vermont	
	Washington	

Data compiled July 31, 2024.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission.
* Within a given subcategory, states are listed in alphabetical order, not by relative ranking.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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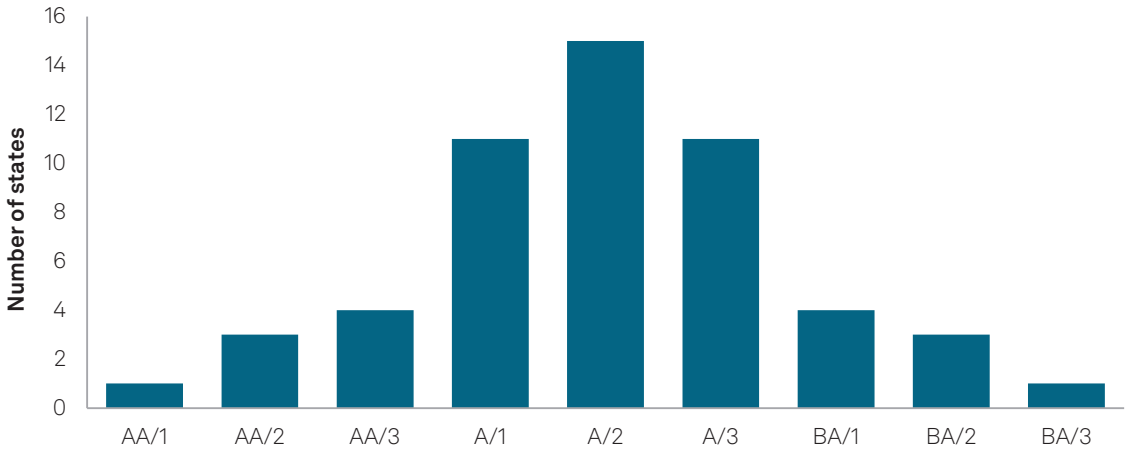
As implied by the above discussion, the rankings reflect the state regulatory commission's decisions and the impact of the actions taken by the governor, the legislature, the courts and consumer advocacy groups. The policies examined pertain largely to rate cases and the ratemaking process, but RRA also consider issues such as industry restructuring, corporate governance, treatment of proposed mergers and those related to the ongoing energy transition.

In the charts within this report that depict the rankings by category, the jurisdictions within each category are listed in alphabetical order rather than by relative position within the category.

State regulatory rankings distribution — energy



Data compiled July 31, 2024.
AA = Above Average; A = Average; BA = Below Average.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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RRA endeavors to maintain an approximately normal distribution, with most rankings in the three average categories and the remainder split almost evenly between the Above Average and Below Average categories.

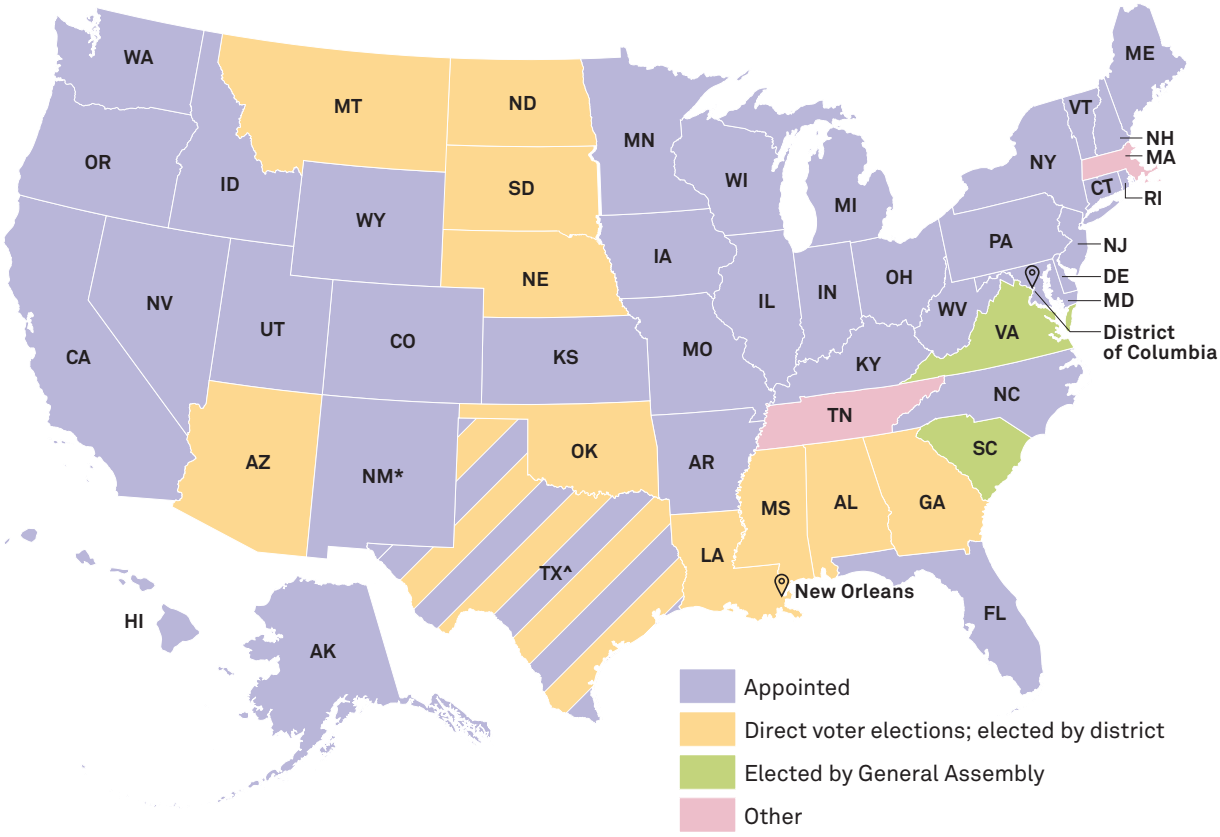
Overview of issues considered in the ranking process

The summaries below provide an overview of the variables RRA looks at, including a brief discussion of how each can impact the ranking of a given regulatory environment.

Governor/Mayor — Actions of the governor (or the mayor in the District of Columbia/City of New Orleans) may impact a jurisdiction's ranking. RRA takes no view on which political party is the more constructive option but does consider to what extent energy issues were of focus of recent elections, whether the governor seeks to become involved in the regulatory process and the type of influence the governor seeks to exert.

Commissioner selection process/membership — RRA examines how commissioners are selected in each state. All else being equal, RRA attributes a greater level of investor risk to states where commissioners are elected rather than appointed. Generally, energy regulatory issues are less politicized when they are not subject to debate in the context of an election.

Commissioner selection methods in US



Data compiled July 31, 2024.
* Prior to Jan. 1, 2023, commissioners were chosen through general elections.
^ The Public Utility Commission of Texas members are appointed by the governor, while members of the Railroad Commission of Texas are elected in statewide elections.
Source: Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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Realistically, a commissioner candidate who indicates support for the utilities and their shareholders or appears amenable to rate increases is unlikely to be popular with voters. In addition, there might not be specific experience requirements to run for commissioner, so a newly elected candidate may have a steeper learning curve with respect to utility regulatory and financial issues, which could make discerning the decisions that an individual might make more difficult and could increase regulatory uncertainty.

There have been some notable instances, however, in which energy issues played a key role in gubernatorial/senatorial elections in states where commissioners are appointed, with detrimental consequences for the utilities.

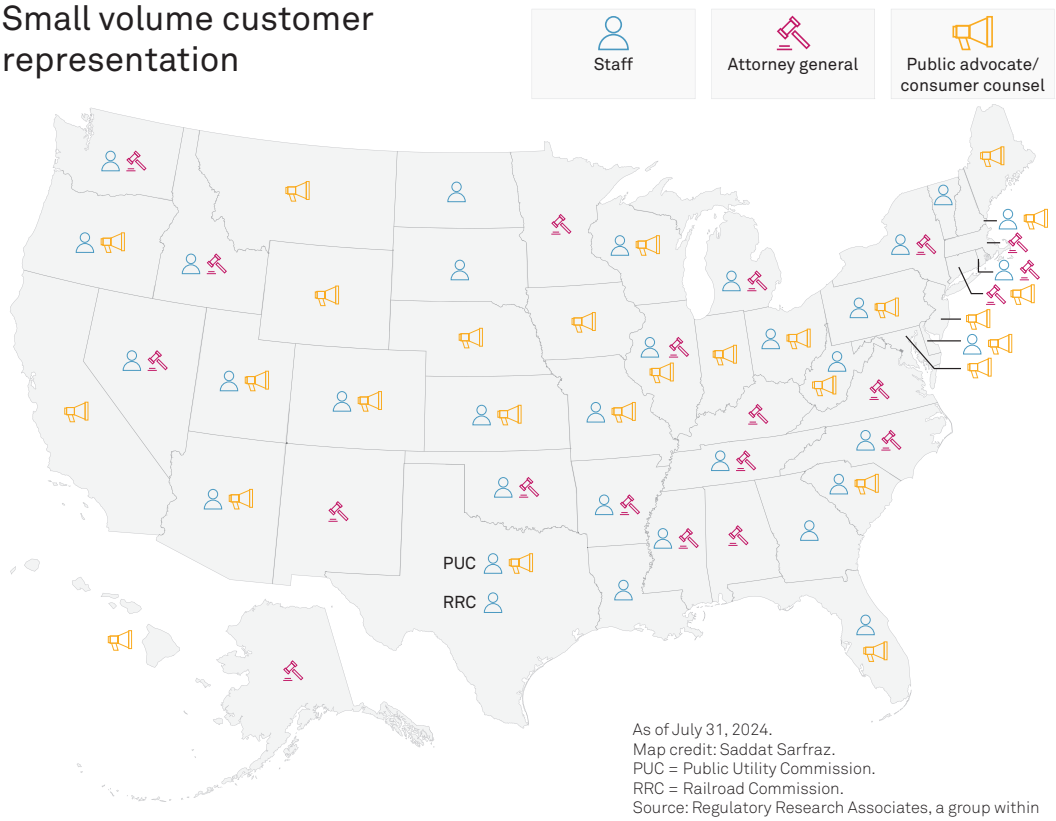
In addition, RRA looks at the commissioners themselves and their backgrounds. Experience in economics and finance and/or energy issues is generally seen as a positive sign. Previous employment by the commission or a consumer advocacy group is sometimes viewed as a negative indicator.

New commissioners with little experience or exposure to utility issues represent the highest level of risk simply because there is no way to foresee their actions or the time they will take to "get up to speed." Controversy or "scandal" surrounding an individual and/or the potential for a conflict of interest are also crucial factors to consider.

Similarly, a high rate of turnover, extended vacancies, and leaving commissioners serving for a long period of time beyond the end of their terms all add to the level of regulatory risk in RRA's view.

Commission staff/consumer interest — Most commissions have a staff that participates in rate proceedings. The staff may represent the consumer interest, act as advisors to the commissioners or play a less defined role. In addition, there may or may not be additional state-level organizations that are charged with representing the interests of a certain class or classes of customers, such as the attorney general or a consumer advocate, coalitions of cities in which the utility operates, private consortia or lobbying groups that represent certain stakeholder groups and/or large-volume commercial and industrial customers that intervene directly in rate cases.

Small volume customer representation



As of July 31, 2024.
Map credit: Saddat Sarfraz.
PUC = Public Utility Commission.
RRC = Railroad Commission.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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Generally, the greater the number of consumer intervenors, the greater the level of uncertainty for investors, as in most instances, the only party representing investors' interests is the company. The level of risk for investors also depends on the caliber and influence of the intervening parties and the level of contentiousness in the rate case process. Even though a commission may not adopt an extreme position taken by an intervenor, the inclusion of an extreme position in the record for the case widens the range of possible outcomes, increasing the risk of a negative outcome for investors. RRA's opinion on these issues is largely based on experience and observations.

Settlements — An increasing number of cases in recent years have been resolved by settlements rather than through a fully litigated process. There are often clear incentives for utilities and entities with vested interests in the sector to compromise. Utilities often obtain settlement benefits in the form of key utility policy objectives and more timely and favorable rate case outcomes than would otherwise be achievable. In some instances, however, settlement negotiations can be protracted and extend the duration of a rate case.

A settlement may set out all of the typical rate case parameters, such as rate of return and rate base, but many are "black box" settlements. These black box settlements are filed when the parties settle all, or nearly all, of their differences in the proceeding, but none of the parties want to disclose the final outcome on a given issue to avoid establishing a precedent.

Or, during settlement discussions, each party may have contemplated a certain revenue change amount as acceptable and may have performed calculations regarding the rate base and rate-of-return parameters behind their revenue requirement positions. Different values for these inputs, however, could be used in varying combinations to determine the same revenue requirement.

All else being equal, the ability of the parties to reach an agreement without having to go through a fully litigated proceeding is considered constructive, particularly since it reduces the likelihood of an after-the-fact court review. However, the agreements are generally less detailed than a fully litigated decision; so, there is a lack of clarity regarding how certain key issues were resolved.

In some instances, the parties may agree on only certain issues and will execute a partial settlement on those issues, while the remaining issues in the case will be litigated.

Rate case timing — For each state commission, RRA considers whether there is a set time frame within which a rate case must be decided, the length of any such statutory time frame and the degree to which the commission adheres to that time frame.

About two-thirds of state commissions nationwide have a rule or statute that requires a rate case to be decided within seven to 12 months of filing; very few have requirements that a case be completed in less than seven months.

Shorter time frames may apply for limited-issue proceedings or if the parties reach an agreement.

RRA generally views a set time frame as preferable, as it provides a degree of certainty as to when any new revenue may begin to be collected. In some states, however, the time frame may be extended with the company's agreement.

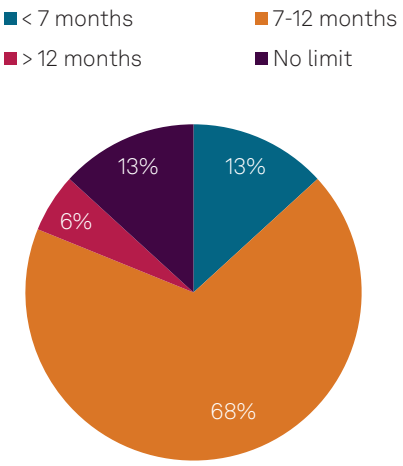
In addition, a shorter time frame for a decision generally reduces the likelihood that the actual conditions, during the first year the new rates will be in effect, will vary markedly from the test period utilized to set new rates, thus keeping regulatory lag to a minimum.

Interim procedures — RRA views the ability to implement all or a portion of a proposed rate increase on an interim basis prior to a final decision as constructive.

In jurisdictions that allow interim rate increases, the utility is required to refund any related over-collections, generally with interest, if the commission approves a rate change that is below the interim rates.

Implementation of an interim increase may be permitted by state law or may require prior approval by the commission, which may not be easy to obtain. Certain states allow a commission to establish an effective date for new rates prior to the final order in the case. The company would then be permitted to recoup any revenue not collected between the effective date and the decision date.

Rate case time frame



Data compiled as of July 31, 2024.
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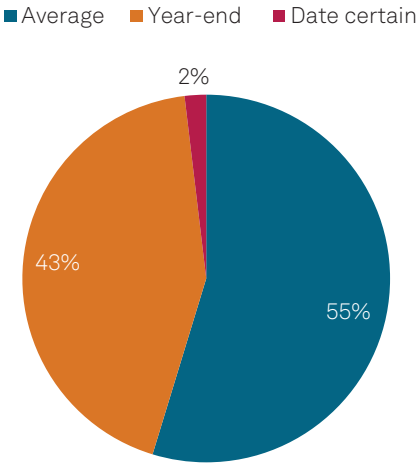
Rate base — A utility's rate base is essentially the company's "prudent" capital investment as determined by the applicable regulatory authorities, net of accumulated depreciation and other adjustments. Rate base is the net asset base of an electric, gas or water utility upon which an allowed rate of return — usually the company's weighted average cost of capital — is applied. The rate base value is a key variable that regulatory bodies use in a rate case to determine a utility's revenue requirement.

A commission's rate base policies can impact a utility's ability to earn its authorized ROE. State statutes often outline these policies, and the commission usually does not have much latitude with respect to these overall policies.

A key factor in assessing whether the company has been accorded a reasonable opportunity to earn the authorized return is the methodology the commission uses to determine rate base.

Commissions are nearly evenly split between those that employ a year-end, or terminal, valuation and those that utilize an average approach, with one using a "date certain" methodology. In some instances, the commission may employ a different rate base valuation method, depending on the utility type or case type or based on the test year selected by the company. For example, a forward-looking test year may be used in a limited-issue rider proceeding or a multiyear rate plan, even though a historical test year is used in traditional single-step base rate cases. Some states allow the utility to choose between a forecast or historical test year but require that an average rate base be used if a forecast test year is requested, while a year-end rate base must be used if a historical test period is selected.

Rate base valuation method



Data compiled July 31, 2024.
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In general, assuming that rate bases are rising, i.e., new investment is outpacing depreciation, a year-end valuation is preferable from an investor viewpoint.

This again relates to how well the parameters used to set rates reflect actual conditions that will exist during the rate-effective period; hence, the more recent the valuation, the more likely it is to approximate the actual level of rate base being employed to serve customers once the new rates are placed into effect.

Some commissions permit post-test-year adjustments to rate base for 'known and measurable' items. Generally, this practice benefits the utilities when operating costs are rising and/or the company is making significant investments in infrastructure and other capital items.

The rules with respect to what constitutes a known and measurable adjustment, however, are not always specific, and there can be a good deal of controversy about what is and is not acceptable under state law or commission rules.

Another key consideration is whether state law and/or the commission generally permits the inclusion in rate base of construction work in progress (CWIP) for a cash return. CWIP represents assets that are not yet operational but ultimately will serve customers. Some states prohibit the inclusion in rate base of items that are not currently, i.e., during the test year or within a reasonably short period of time following the end of the test year, 'used and useful' in providing service to customers. Thus, CWIP must be excluded.

In these instances, the companies are permitted to accrue allowance for funds used during construction (AFUDC), which is essentially booking a return on the construction investment as a regulatory asset that is recoverable from ratepayers once the project in question becomes operational. While this method bolsters earnings, it does not augment cash flow and does not support credit metrics.

Investors generally view the inclusion of CWIP in rate base for a cash return as constructive since it helps to maintain cash flow metrics during a large construction cycle. In addition, if the company is not able to time its next rate case to coincide with the in-service date of a project, there may be a time period where the plant is operating and, therefore, the company can no longer accrue AFUDC but the utility is incurring operations and maintenance costs and booking depreciation expense, none of which are yet reflected in rates.

This becomes particularly challenging when the utility's construction program consists of several smaller projects with short ramp-up times, making it more difficult for the company to file a case quickly enough to reflect each new project.

Test year — The rate case test year is simply the 12-month period used as a baseline in examining the utility's actual revenues, expenses and rate base. In assessing the level of regulatory risk, RRA examines whether a historical test year is chosen or a future 12-month period with a forecast of the utility's revenues, expenses and rate base.

Almost two-thirds of the 53 jurisdictions covered by RRA utilize a test year that is historical at the time of filing, which increases regulatory lag and uncertainty for investors.

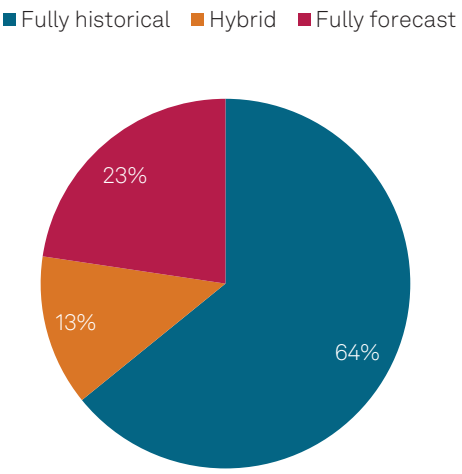
A fully forecast test year is generally considered to be most constructive, particularly in periods of robust capital spending, high inflation and rising interest rates.

Under a hybrid approach, the test year is partially forecast at the time the case is filed but is fully historical by the time the case is decided. The company generally files updates during the proceeding to reflect actual results as they become available.

Some jurisdictions use different test period types for different kinds of proceedings or utilities. For example, the commission may use a historical test year for single-year base rate cases but the use forward-looking test years for multiyear rate cases, alternative regulation plans and/or adjustment clauses.

Many jurisdictions allow for known and measurable adjustments to the test year, but there is considerable variability regarding how far beyond the end of the test year these adjustments may go, and statutes governing the definition of known and measurable can be ambiguous. Consequently, there can be wide disagreement among the rate case parties as to which adjustments qualify.

Rate case test year



Data compiled July 31, 2024.
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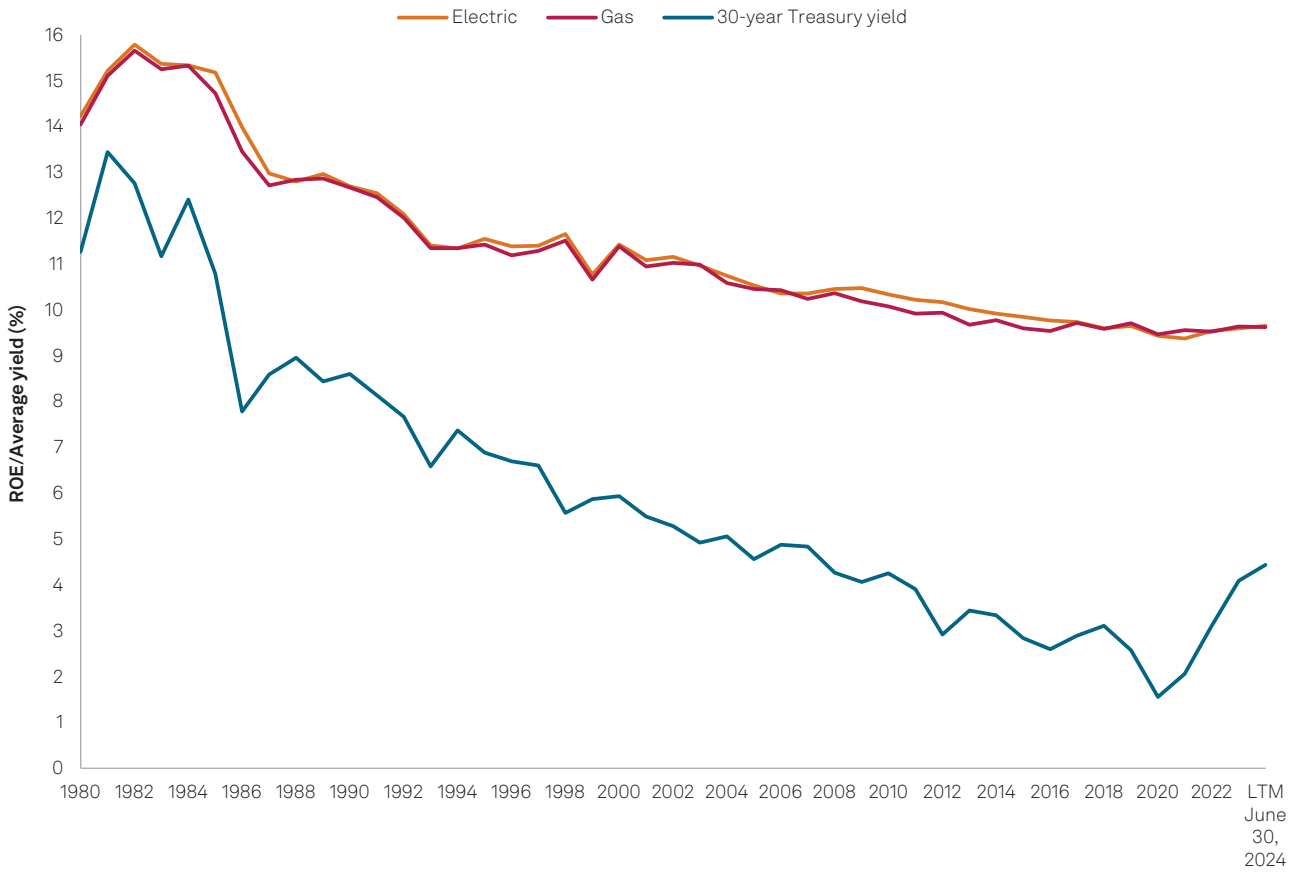
Conversely, in periods where there is only a modest amount of capital spending, i.e., depreciation is outpacing new spending, low inflation and falling interest rates, the use of a historical test year and the associated regulatory lag would work in the utility's favor, as rates would likely reflect higher costs than the utility incurs.

Rate of return — The capital structure, debt cost rates and authorized equity return combine to determine the company's weighted average cost of capital, which is known as the return on rate base in the context of a rate case.

Return on equity (ROE) — The authorized ROE is perhaps the single-most litigated issue in any rate case. Commissions generally rely on financial formulas, such as the discounted cash flow, capital asset pricing model and risk premium approaches, as applied to a proxy group of companies with similar risk characteristics.

Average authorized ROE for US utilities, 30-year Treasury bond yields

Calendar years 1980 - 2023. LTM June 30, 2024



Data compiled July 24, 2024
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
LTE = Last 12 months.
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While these financial models appear objective, there are subjective judgments that go into many aspects of the analysis: the appropriate peer group, the level of risk in the subject company's operations and how it may differ from that of the proxy group and whether there are any other factors that warrant an adjustment to the base calculations.

In establishing rankings, RRA looks at the ROEs historically authorized utilities in a given state and compares them to nationwide industry averages, as calculated in RRA's Major Rate Case Decisions Quarterly Update reports. When referring to these "averages," RRA means the simple average of the ROEs approved in cases decided in a particular period; returns carried over from prior years are not included in the averages.

How the authorized ROEs in a given state compare to prevailing nationwide industry averages is only one aspect of RRA's analysis. Any given utility may be authorized a relatively high ROE, but factors such as the age or "staleness" of the test period, rate base valuation method, adjustments to the company-proposed rate base and expenses, and the way the commission chooses to calculate test year revenue and other adjustments may render it unlikely that the company will earn the authorized return.

Hence, a given rate case decision may be restrictive from an investor viewpoint, even though the authorized ROE is equal to or above the average.

Capital structure — The equity layer in the authorized capital structure is another aspect of a commission rate case decision that may impact the utility's ability to earn the authorized ROE. Most commissions utilize the company's actual capital structure at a given point in time, but in some instances, the commission may rely on an imputed capital structure that represents a mix of debt and equity that the commission views as more reasonable or economically efficient. These are known as hypothetical capital structures.

The commission may include short-term debt and/or other items not generally considered to be part of the utility's cost of capital for financial reporting purposes, such as job development investment tax credits, customer deposits or accumulated deferred taxes (as an alternative to reflecting accumulated deferred tax balances as an offset to rate base). These are generally considered "ratepayer supplied capital" and are accorded a blended cost based on the company's financial weighted average cost of capital or may be assigned a cost rate of zero. Such capital structures are known as regulatory capital structures.

If a commission uses a capital structure that is more highly leveraged than the company's actual structure, this will lower the authorized overall return and the revenue requirement ultimately approved and render it more difficult for the company to earn the authorized return on its actual equity, all else being equal.

Senior capital cost rates — The costs of long- and short-term debt are generally set at the weighted average interest rate on the outstanding issuances. While it is rare, a commission may choose to exclude a recent debt refinancing that alters the company's debt cost rate or may determine that the company was slow to take advantage of opportunities to refinance debt at a lower cost rate. If this occurs, and the senior capital cost rates used to set rates are lower than those that the company will experience while rates are in effect, then the utility will have a more difficult time earning its authorized ROE.

The cost of preferred stock, where there is any, is set based on the guaranteed dividend rate on the outstanding shares.

Accounting — RRA looks at whether a state commission has permitted unique or innovative accounting practices designed to bolster earnings. Such treatment may be approved in response to extraordinary events, such as severe weather events or the COVID-19 pandemic, and changes in federal tax laws, or for volatile expenses, such as fuel and pension costs. Generally, such treatment involves deferral of expenditures that exceed the level of such costs reflected in base rates. In some instances, the commission may approve an accounting adjustment, such as a change in depreciation rates, to temporarily bolster certain financial metrics or to eliminate over-earnings without requiring a full-blown rate case.

Actions taken to address emerging issues and their impact on the utilities are also key. For example, in the wake of the energy transition movement, an increasing number of fossil generation facilities and legacy meters are being retired early. Other types of utility assets are also at risk of becoming "stranded" costs as the transition progresses. In some states, companies have been permitted to accelerate depreciation of certain facilities to complete recovery of the investment prior to an accelerated shutdown of the asset. In others, the utilities are permitted to defer the remaining book value at closure as a regulatory asset that is to be recovered over a period of years; the unamortized balance may or may not be accorded a return.

Alternative regulation — RRA generally views as constructive the adoption of alternative regulation plans that are designed to streamline the regulatory process and accelerate cost recovery or allow utilities to augment earnings in some way. These plans can be broadly or narrowly focused.

Narrowly focused plans may allow the company to retain a portion of cost savings relative to a base level of some expense type (e.g., fuel, purchased power, pension cost, etc.), permit a company to retain a portion of off-system sales revenues for shareholders or provide a company an enhanced ROE for achieving operational performance and/or customer service metrics or for investing in certain types of projects (e.g., demand-side management programs, renewable resources, new traditional plant investment, etc.).

Broad-based plans include ROE-based sharing mechanisms, formula-based rates and MRPs that apply to all cost-of-service issues rather than specific investments or expenses. These types of plans may also include performance-based incentives.

The use of plans with somewhat broader scopes, such as ROE-based earnings-sharing plans, is, for the most part, considered to be constructive, but it depends upon the level of the ROE benchmarks specified in the plan — if any deadband that applies is symmetrical around the ROE target, and whether variations from the benchmark or outside the deadband are shared symmetrically.

Formula-based ratemaking plans generally refer to frameworks where the commission establishes a revenue requirement, including a target ROE, capital structure and rate of return for an initial rate base as part of a traditional cost-of-service base rate proceeding. Once the initial parameters are set, rates may adjust periodically to reflect changes in expenses, revenue and capital investment. These changes generally occur on an annual basis, and there may be limitations on the percentage change that can be implemented in a given year or a period of years.

Others use multiyear rate plans, under which the commission approves a succession of rate changes that are designed to consider anticipated changes in revenues, expenses and rate base. The commission may approve a static authorized ROE, or the plan may provide for adjustments to the ROE during the plan's term. These plans often include true-up mechanisms to ensure that the company makes the investments it committed to at the time the plan was approved. The plans often include earnings-sharing mechanisms and may also include PBR provisions or stay-out provisions, preventing a company from filing a successive rate case until a future point in time.

Court actions — This aspect of state regulation is particularly difficult to evaluate. Common sense would dictate that a court action that overturns restrictive commission rulings is a positive. However, the tendency for commission rulings to come before the courts and for extensive and sometimes protracted litigation as appeals go through several layers of court review may add an untenable degree of uncertainty to the regulatory process. Also, as is the case with commissioners, RRA looks at whether judges are appointed or elected, as political considerations are more likely to influence elected jurists.

Legislation — While RRA's commission profiles provide statistics regarding the makeup of each state legislature, RRA has not found a specific correlation between the quality of energy legislation enacted and the political party controlling the legislature.

If the governor and legislature are of the same political party, it is less likely that controversy will arise around key policy initiatives, which may directly or indirectly impact the energy regulatory framework. In instances where energy issues are a main focus, a lack of consensus between the legislative and executive branches of the state government can create uncertainty and increase risk for utility investors and other industry stakeholders.

Key considerations with respect to legislation include how prescriptive newly enacted laws are; whether the bill is clear or ambiguous and open to varied interpretations; whether it balances ratepayer and shareholder interests rather than only "protecting" the consumer; whether the legislation takes a long-term view or is a "knee-jerk" reaction to a specific set of circumstances; and whether it could constrict the utilities' opportunities to achieve their business objectives.

Legislative activity impacting utility regulatory issues has been robust in recent years as state policymakers, utilities and industry stakeholders seek to address 'disruptors' that challenge the traditional regulatory framework.

RRA follows these developments closely to assess whether the states take a balanced, sustainable approach and how the adopted policies will affect legacy utility providers.

Corporate governance — The term corporate governance generally refers to a commission's ability to intervene in a utility's financial decision-making process through required preapproval of all securities issuances, limitations on leverage in utility capital structures, dividend payout limitations, ring-fencing protocols and authority over mergers. Corporate governance may also include oversight of affiliate transactions.

RRA views a modest level of corporate governance provisions to be the norm, and in some circumstances, these provisions, such as ring fencing, have protected utility investors as well as ratepayers. However, a degree of oversight that would allow the commission to "micromanage" the utility's operations, limit the company's financial flexibility or significantly reduce the company's ability to pursue strategic mergers would be viewed as restrictive.

In recent years, RRA has observed an increasing emphasis on environmental, social and governance issues, and supplier and workforce diversity and social justice issues. In many instances, these policies are part of the ongoing energy transition. At this time, RRA takes no view on whether policymakers/regulators should adopt these practices, but when specific policies or targets are implemented, RRA evaluates how compliance costs are addressed.

M&A activity — The pace of merger activity fluctuates over time and consequently, so does the importance of a commission's merger policies.

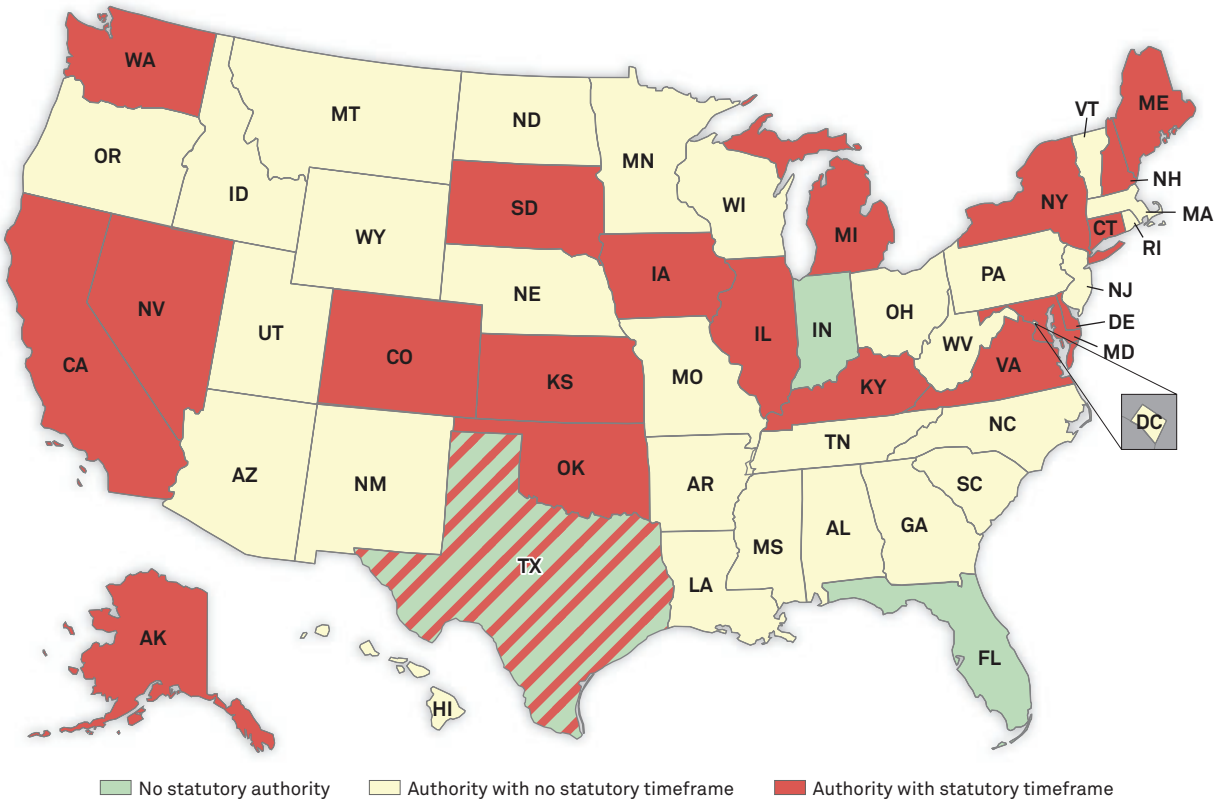
Deals involving regulated utilities are subject to review by all but three of the 53 state-level jurisdictions followed RRA follows.

The review process and standards vary widely for the 50 jurisdictions where commission preapproval is required. In 20 of the jurisdictions, the commission must complete a merger review within a prescribed period, but the remaining jurisdictions have no timeline for their merger reviews, which means a commission could effectively "pocket veto" a transaction by delaying a decision until either the merger agreement between the applicants expires or pursuing the transaction is no longer feasible.

The definition of what constitutes a transaction that is subject to review can vary widely and may include sales of individual assets or a marginal minority interest, as well as larger transactions where a controlling interest or the whole company is changing hands. State law often lacks specificity with respect to what constitutes a transaction that is subject to regulatory review.

In cases where the state commission has authority over mergers, RRA reviews the type of approval standard that is contained in state law and/or has been applied in specific situations.

Utility mergers — statutory authority



As of July 31, 2024.
In Texas, mergers involving electric utilities are subject to commission review; mergers involving local gas distribution companies are not.
Map credit: Arleigh Andes.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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For discussion purposes, RRA groups the statutory standards into three general buckets: public interest, which is generally thought to be the least restrictive; no net ratepayer harm, which is somewhat more restrictive; and net ratepayer benefit, which is the most restrictive.

In many instances, regulators have broad discretion to interpret what the statutes mean by these terms. So, the standard of review is often more readily apparent by looking at how prior transactions were addressed than by reading the statutory language — one commission's public interest might be another's net ratepayer benefit.

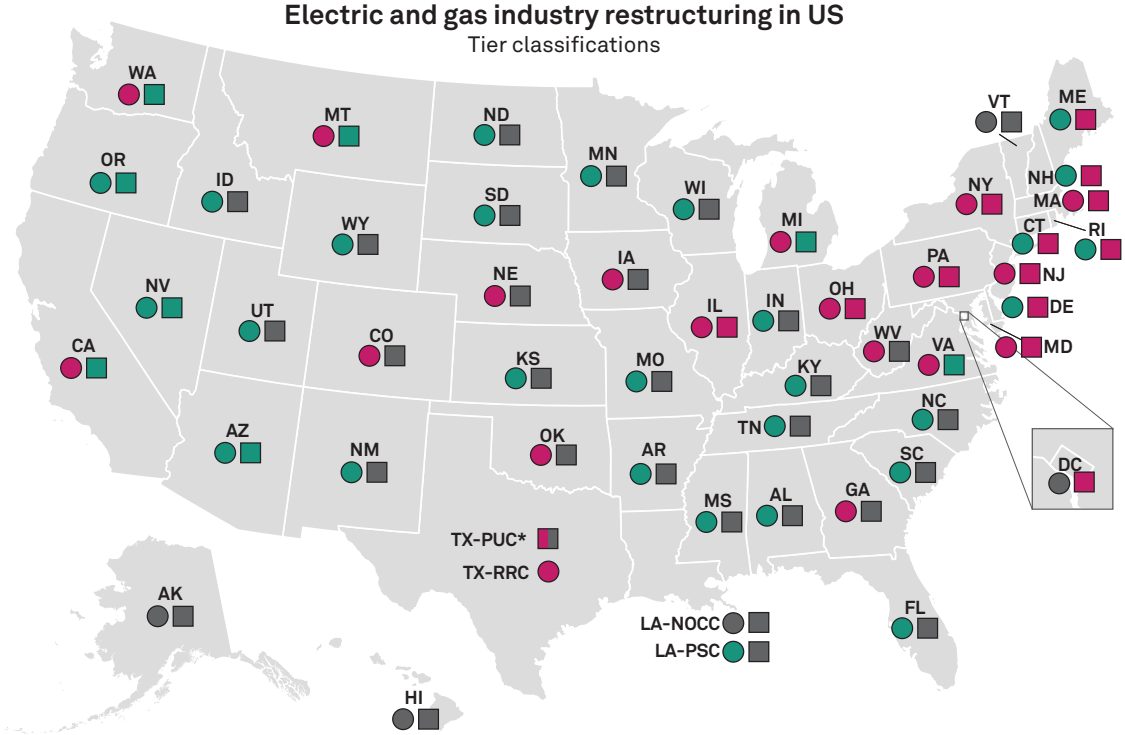
In addition, RRA considers whether the parties reached a settlement and, if so, whether the commission honored that settlement or required additional commitments. RRA also examines how politicized the process was: Did the governor (or the mayor in the District of Columbia and the City of New Orleans) play a role? Did the transaction garner much local media attention in the affected jurisdiction?

More narrowly, RRA reviews the conditions placed on the commission's approval of these transactions, including whether the company will be permitted to retain a portion of any merger-related cost savings, if guaranteed rate reductions or credits are required that are or are not directly related to merger savings, whether certain assets were required to be divested, the type of local control and workforce commitments required, whether there are requirements for certain types of investment to further the state's public policy goals that may or may not be consistent with the companies' business models and if the related costs will be recoverable from ratepayers and whether the commission placed stringent limitations on capital structure and/or dividend policy or composition of the board of directors.

Electric regulatory reform/industry restructuring — Electric industry restructuring refers to the implementation of a framework under which some or all retail customers can obtain their generation service from a competitive supplier of their choice. In a movement that began in the mid-1990s, about 20 jurisdictions implemented retail competition for all or a portion of the customers in the utilities' service territories. The last of the transition periods ended as recently as 2011, when restructuring-related rate freezes concluded for certain Pennsylvania utilities.

Electric and gas industry restructuring in US

Tier classifications



Gas tiers

Tier 1 — All customers are permitted to competitively procure their gas supply, irrespective of volumes.

Tier 2 — Select customers are permitted to competitively procure their gas supply, usually based on volume.

Tier 3 — All customers procure their gas supply from the utility under bundled rates.

Power tiers

Tier 1 — Power prices are competitively determined for all retail customers within the jurisdiction; both standard-offer-service and retail-access customers.
Retail access is permitted for all customers.

Tier 2 — Retail access is permitted to at least some customers/customer classes. Competitively priced power is limited to retail access customers. Power prices for standard-offer-service customers remain regulated.
For the most part, utilities remain vertically integrated.

Tier 3 — Power prices are fully regulated for all retail customers. All retail customers must purchase their power from the franchised utility. Utiities are vertically integrated.

As of July 31, 2024.
NOCC = New Orleans City Council; PSC = Public Service Commission; PUC = Public Utility Commission; RRC = Railroad Commission.
* One in the Electric Reliability Council of Texas territory; three outside of it.
Map credit: Joe Felizadio.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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Once the transition periods were completed, RRA focused more on how standard-offer or default service is procured for customers who do not select an alternative provider and how much, if any, market-price risk the utility must absorb. RRA classifies each of the regulatory jurisdictions into one of three tiers based on their relative electric industry restructuring status.

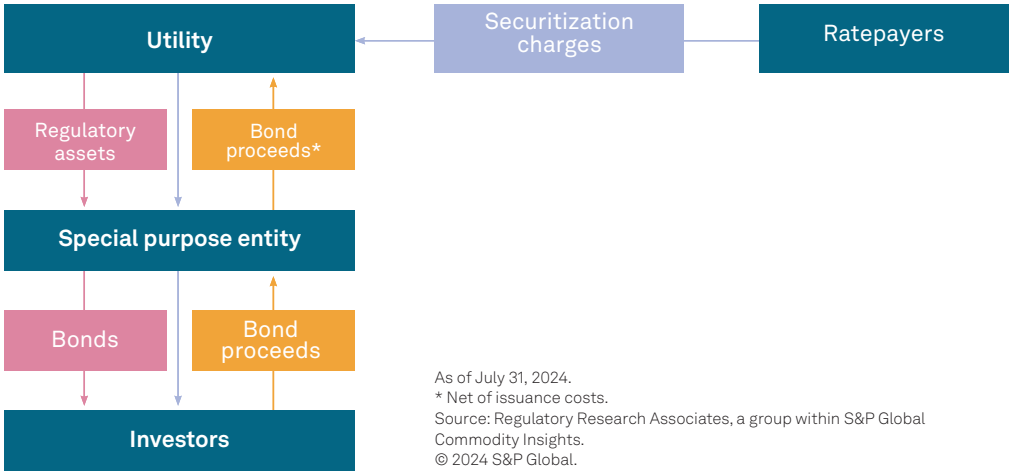
Gas regulatory reform/industry restructuring — Retail competition for gas supply is more widespread than electric retail competition, and the transition was far less contentious, as the magnitude of stranded asset costs was much smaller due to the more disaggregated structure of the industry.

Large-volume customers in most states can select their gas supply provider; the availability of gas customer choice is much more limited for small-volume customers. Like electric retail competition, RRA generally does not view a state's decision to implement retail competition for gas service as either positive or negative from an investor viewpoint. RRA primarily considers how stranded costs are addressed and how default-service, obligation-related costs are recovered.

Securitization — As it pertains to utilities, securitization refers to the issuance of bonds backed by a specific existing revenue stream that regulators and/or state legislators have 'guaranteed.' This does not mean that the securities are backed by the 'full faith and credit' of the jurisdiction but instead provides certainty that the revenue collections and/or underlying assets cannot be deemed imprudent and disallowed in the future.

Securitization generally requires a utility to assign an eligible regulatory asset and a designated revenue stream for that asset to a 'bankruptcy remote' special-purpose entity or trust; in some instances, a state financing authority fulfills this role. The trust or financing authority, in turn, issues bonds that the transferred revenue stream will service. The proceeds from the bond issuance flow to the utility and, in many cases, are used to retire outstanding higher-cost debt and/or buy back common equity, thus lowering the company's weighted average cost of capital.

Securitization flow chart



As of July 31, 2024.
* Net of issuance costs.
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While it is unclear if securitization requires legislation, a specific legislative mandate generally improves the rating accorded securitization bonds and lowers the associated cost of capital, given that a legislatively supported revenue stream may be more difficult to rescind than a stand-alone order of a state commission. In RRA's experience, no state commission has authorized securitization in the absence of enabling legislation.

Securitization is viewed as an attractive option because it allows regulators to minimize the customer rate impacts related to the recovery of a particular utility asset. The carrying charge on the asset would be the lower interest rate applied to a highly rated, usually AAA, corporate bond rather than the utility's weighted average cost of capital or even the interest rate on typical utility bonds, which are generally rated BBB and carry higher interest rates.

At the same time, securitization reduces the investment risk for the utility by providing the utility with up-front recovery of its investment in what are usually non-revenue-producing assets. The company can then redeploy those investment dollars elsewhere.

Securitization has been used for various purposes to finance energy efficiency and conservation investment, address stranded costs associated with the implementation of retail competition or the extension of energy transition policies, reduce the impact on ratepayers of recovery of extraordinary storm costs or unusually high deferred balances or to finance bankruptcy reorganization plans.

Adjustment clauses — Adjustment clauses have been widely utilized to allow utilities to recover fuel and purchased power costs outside of base rate cases, as these costs are generally subject to a high degree of variability. In some instances, a baseline level is reflected in base rates, with only deviations from that amount addressed in the adjustment clause, whereas in others, the entire annual fuel/purchased power cost amount is reflected in the clause.

Over time, the types of costs recovered through these mechanisms were expanded in some jurisdictions to include items such as pension and healthcare costs, demand-side management program costs, Federal Energy Regulatory Commission-approved regional transmission organization costs, new generation plant investment, and transmission and distribution infrastructure spending.

RRA generally views the use of these types of mechanisms as constructive but also looks at the frequency with which the adjustments occur and whether: there is a true-up mechanism; adjustments are forward-looking or based on a historical period; a cash return on CWIP is permitted for mechanisms involving new investments; the mechanism includes an earnings-sharing mechanism that offers the utility upside earnings potential; or incentive(s) for making certain types of investment or for achieving benchmark performance that provide the opportunity to increase earnings.

Another class of adjustment clauses, known as revenue decoupling mechanisms, allows utilities to adjust rates between rate cases to reflect fluctuations in revenues versus the level approved in the most recent base rate case due to various factors.

Some of these factors, such as weather, are beyond a utility's control, and the mechanism can work both ways — it can allow the company to raise rates to recoup revenue losses associated with weather trends that reduce customer usage, and conversely, it can also require the company to reduce rates when weather trends cause usage to be higher than normal.

As energy efficiency initiatives have expanded, decoupling mechanisms have also been implemented to reduce the disincentive for utilities to pursue these types of programs by making the utilities whole for reductions in sales volumes and revenues associated with customer participation.

Some of these mechanisms also allow the utility to adjust rates to reflect fluctuations in customer usage that are brought about by broader economic issues, such as demographic shifts, large commercial/industrial customers migrating to other service areas, businesses shutting down due to changes in their respective industries, recessions and, theoretically, broad-based crises like the COVID-19 pandemic.

RRA considers a decoupling mechanism that adjusts for all three of these factors to be a "full" decoupling mechanism and designates those that address only one or two of these factors as "partial" decoupling mechanisms.

Generally, an adjustment mechanism would be viewed as less constructive if there are provisions that limit the utility's ability to fully implement revenue requirement changes under certain circumstances, e.g., if the utility is earning more than its authorized return or if the adjustment exceeds a certain threshold.

Integrated resource planning — RRA generally considers the existence of a resource-planning process to be constructive from an investor viewpoint, as it may provide the utility at least some measure of protection from hindsight prudence reviews of its resource acquisition decisions. In some cases, the process may also provide for preapproval of the ratemaking parameters and/or a specific cost for a new facility. RRA views these types of provisions as constructive, as the utility can make more informed decisions as to whether it will proceed with a proposed project based on the expected level of support a utility proposal receives from regulators.

Renewable energy/emissions requirements — Goals for renewable energy deployment and emissions reductions have become increasingly intertwined in recent years and often need to be viewed in tandem.

As with retail competition, RRA does not take a stand as to whether the implementation of renewable portfolio standards or an emissions reduction mandate is positive or negative from an investor viewpoint. However, RRA considers whether there is a defined preapproval and/or cost-recovery mechanism for investments in projects designed to comply with these standards.

RRA also reviews if there is a mechanism, such as a rate increase cap, that limits the impact of the related public policy goals on customers. Such a mechanism could impede the utility's ability to recover program-related costs, pursue additional investments and/or recover increased costs related to other facets of its business. RRA also looks at whether incentives, such as an enhanced ROE, are available for these types of projects.

The proliferation of renewables, particularly those that are customer-sited or distributed resources, and the related rise of battery storage and electric vehicles have raised questions regarding the traditional centralized industry framework and whether that framework needs to change, ushering in a second phase of electric industry restructuring. How these changes are implemented is something RRA considers in its rankings.

With respect to emissions, the threat of a federal carbon emissions standard for utilities and the spread of state-level initiatives have caused many companies to rethink legacy coal-fired generation, causing plants to be shut down sooner than anticipated. The way the commissions address these potential stranded costs also poses a risk for investors and is factored into the rankings.

The zero-carbon movement has also caused utilities/states to reexamine investments in nuclear facilities and, in some cases, to develop programs designed to support the continued operation of those facilities, even though they may not be economic from a competitive-market standpoint. RRA also considers the way these issues are addressed.

Rate structure — RRA looks for existing rate structures related to economic development or load retention. If such structures are in place, RRA examines whether and how any associated revenue shortfall is addressed. More broadly, RRA looks at any steps taken in rate cases to reduce/eliminate interclass rate subsidies, i.e., to equalize rates of return across customer classes.

In addition, RRA considers whether the commission has adopted or moved toward a straight-fixed-variable rate design, under which a greater portion of a company's fixed costs are recovered through the fixed monthly customer charge, thus providing the utility greater certainty of recovering its fixed costs.

This is increasingly important in an environment where weather patterns are more volatile, energy efficiency/conservation programs proliferate and large amounts of nonrevenue-producing capital spending are required to upgrade and harden the grid.

In conjunction with the influx of renewables and distributed generation, issues surrounding the level of compensation owed to customer-owners for excess power they put back into the grid have become increasingly important and, in some instances, controversial. The way these pricing arrangements, known as net metering, are structured can impact the ability of the utilities to recover their fixed distribution system costs and, by extension, their ability to earn their authorized returns.

RRA also looks at whether the state has implemented policies to address electric vehicle charging and time-of-use rates, as well as tariffs for renewable natural gas.

Fixed vs. variable costs

Fixed	Variable
Depreciation	Gas commodity
Delivery O&M	Electric commodity
Property taxes	Generation O&M
Return on investment	
Customer service	

Data compiled as of July 31, 2024
O&M=operations and maintenance.
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.
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Further Reading

Jurisdictions with ranking changes

New investment rider among key aspects of case ruling for Arizona Public Service

Evergy-backed cost recovery bill approved by Kan. state House

ONE Gas Kan. utility backs condensed performance-based approach to ratemaking

NorthWestern files Mont. rate cases to address $1B of capital expenditures

Parties recommend significant disallowances in Chesapeake's Md. rate case

Md. regulators reject Exelon multiyear plan, opt for one-time rate increase

Md. governor to consider handful of energy bills as legislative session ends

Mich. commission staff supports smaller electric rate increase for DTE Energy

Mich. regulators adopt settlement, pare back rate increase for Consumers Energy

Mich. regulators halve electric rate request by Indiana Michigan Power

Recent developments signal shifts in energy regulatory climate in 2 states

Jurisdictions to watch

Ariz. regulators focus on renewables, test years, other varied issues

Decision on tap in Avangrid's Conn. gas rate cases

Iberdrola deal to buy rest of Avangrid to face some regulatory scrutiny

United Illuminating files brief urging court to reverse negative rate decision

Conn. lawmakers look to update state climate goals, study gas phaseout options

Commonwealth Edison seeks to address regulatory uncertainty with new grid plan

With new grid plan filing, Ameren seeks to assuage commission's prior concerns

Commission to resolve post-hearing issues in Alliant's Iowa base rate case

Alliant's Iowa settlement includes 5-year electric rate increase moratorium

Black Hills Iowa Gas requests $20.7M rate hike for capex, higher operating costs

Rider risk profile a prominent focus in Columbia Gas' Ky. rate change request

Elizabethtown Gas files 1st rate case since acquisition by infrastructure fund

Okla. commission staff concerned with AEP utility's rider, tree trimming plans

Okla. commission staff criticizes vegetation management practices at OGE utility

Parties reach unopposed settlement in AEP Texas rate case

Settlement talks begin in CenterPoint's Texas rate case amid storm controversy

Texas governor appoints consumer advocate to PUC

Wyo. consumer advocate seeks additional conditions in Enbridge-Dominion deal

Low-carbon standard, rates, reliability top list for Wyo. lawmakers

Industry trends

Energy authorized returns edge higher in H1 2024

First-half 2024 utility rate requests above average but trail 2023's record

Flurry of energy rate case activity underway in US

Utility capex primed for profusion in 2024 and beyond

RRA reference reports

Demystifying rate base mechanics can be instructive for industry practitioners

Understanding main aspects of case process empowers utility sector participants

For detailed information about each jurisdiction's policies and regulatory ranking, visit the Commissions page on S&P Capital IQ Pro.

For a full listing of past and pending rate cases, rate case statistics and upcoming events, visit the Energy Research Home Page on S&P Capital IQ Pro.

For a complete, searchable listing of RRA's in-depth research and analysis, please go to the Energy Research Library S&P Capital IQ Pro.

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About Regulatory Research Associates

Regulatory Research Associates, a group within S&P Global Commodity Insights, is the leading authority on utility securities and regulation. Understanding the financial and strategic impact of federal and state regulation is a key to success in the energy business. For more than 40 years, Regulatory Research Associates has been the leading provider of independent research, expert analysis, proprietary data and consultation on utility securities and regulation. S&P Global Commodity Insights produces content for distribution on S&P Capital IQ Pro.

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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
($000)

Case No.: U-21806
Exhibit No.: A-37 (JRB-2)
Page: 1 of 4
Witness: JRByrom
Date: December 2024

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2023	(c) Projected 12-Mos Ending 10/31/2026
1	Billing & Payment	15,054	10,868
	Labor	2,391	2,448
	Material	842	824
	Contractor	6,664	1,546
	Non-Labor Overhead	-	-
	Non-Labor Other	5,157	6,050
2	Customer Interactions	21,634	20,978
	Labor	15,749	15,550
	Material	36	46
	Contractor	4,835	4,382
	Non-Labor Overhead	-	-
	Non-Labor Other	1,013	999
3	Total CXCO O&M Expenses	36,689	31,846
	Labor	18,141	17,998
	Material	878	870
	Contractor	11,499	5,928
	Non-Labor Overhead	-	-
	Non-Labor Other	6,171	7,049

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
($000)

Case No.: U-21806
Exhibit No.: A-37 (JRB-2)
Page: 2 of 4
Witness: JRByrom
Date: December 2024

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2023	(c) Projected 12-Mos Ending 10/31/2026
1	Customer Billing	8,687	9,492
	Labor	2,072	1,928
	Material	840	824
	Contractor	666	707
	Non-Labor Overhead	-	-
	Non-Labor Other	5,109	6,032
2	Customer Payment Programs	6,368	1,376
	Labor	320	519
	Material	2	-
	Contractor	5,998	838
	Non-Labor Overhead	-	-
	Non-Labor Other	49	18
3	Total Billing & Payment O&M Expenses	15,054	10,868
	Labor	2,391	2,448
	Material	842	824
	Contractor	6,664	1,546
	Non-Labor Overhead	-	-
	Non-Labor Other	5,157	6,050

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Add Description
($000)

Case No.: U-21806
Exhibit No.: A-37 (JRB-2)
Page: 3 of 4
Witness: JRByrom
Date: December 2024

Line No.	(a) Description	(b) Actual 12-Mos Ending 12/31/2023	(c) Projected 12-Mos Ending 10/31/2026
1	Analytics & Outreach	2,656	2,325
	Labor	2,065	1,742
	Material	4	-
	Contractor	520	509
	Non-Labor Overhead	-	-
	Non-Labor Other	67	74
2	Business Customer Care	1,826	1,776
	Labor	1,557	1,474
	Material	1	-
	Contractor	235	258
	Non-Labor Overhead	-	-
	Non-Labor Other	34	44
3	Credit & Assistance	2,270	2,562
	Labor	1,544	1,713
	Material	10	46
	Contractor	534	651
	Non-Labor Overhead	-	-
	Non-Labor Other	183	152
4	Customer Contact Center	12,998	13,243
	Labor	10,029	9,940
	Material	21	-
	Contractor	2,255	2,595
	Non-Labor Overhead	-	-
	Non-Labor Other	693	708
5	Digital Customer Operations	1,884	1,072
	Labor	555	682
	Material	0	-
	Contractor	1,292	369
	Non-Labor Overhead	-	-
	Non-Labor Other	36	21
6	Total Customer Interactions O&M Expenses	21,634	20,978
	Labor	15,749	15,550
	Material	36	46
	Contractor	4,835	4,382
	Non-Labor Overhead	-	-
	Non-Labor Other	1,013	999

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
($000)

Case No.: U-21806
Exhibit No.: A-37 (JRB-2)
Page: 4 of 4
Witness: JRByrom
Date: December 2024

Line No.	Description	(a)	(b) Actual 12 Mos Ending Dec 31, 2023	(c) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2023	(d) Merit & Inflation 12 Mos Ending Dec 31, 2024	(e) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	(f) Merit & Inflation 12 Mos Ending Dec 31, 2025	(g) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	(h) Merit & Inflation 10 Mos Ending Oct 31, 2026	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending Oct 31, 2026
					(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	Billing & Payment		15,054	15,054	482	15,536	373	15,909	331	(5,373)	10,868
	Labor		2,391	2,391	77	2,468	59	2,527	53	(132)	2,448
	Material		842	842	27	869	21	890	19	(85)	824
	Contractor		6,664	6,664	213	6,877	165	7,042	147	(5,643)	1,546
	Non-Labor Overhead		0	0	0	0	0	0	0	0	0
	Non-Labor Other		5,157	5,157	165	5,322	128	5,450	114	487	6,050
2	Customer Interactions		21,634	21,634	692	22,327	536	22,862	476	(2,361)	20,978
	Labor		15,749	15,749	504	16,253	390	16,643	347	(1,440)	15,550
	Material		36	36	1	37	1	38	1	7	46
	Contractor		4,835	4,835	155	4,990	120	5,110	106	(834)	4,382
	Non-Labor Overhead		0	0	0	0	0	0	0	0	0
	Non-Labor Other		1,013	1,013	32	1,046	25	1,071	22	(94)	999
3	Total CXCO O&M Expenses		36,689	36,689	1,174	37,863	909	38,771	808	(7,734)	31,846
	Labor		18,141	18,141	581	18,721	449	19,171	399	(1,571)	17,998
	Material		878	878	28	906	22	928	19	(78)	870
	Contractor		11,499	11,499	368	11,867	285	12,152	253	(6,477)	5,928
	Non-Labor Overhead		0	0	0	0	0	0	0	0	0
	Non-Labor Other		6,171	6,171	197	6,368	153	6,521	136	393	7,049

Notes

	12-Mo Ending 2024	12-Mo Ending 2025	10-Mo Ending 2026
Annual inflation rates per Company witness Rayl	3.2%	2.4%	2.5%
Number of months in the period	12	12	10
Pro-rated inflation rate	3.2%	2.4%	2.1%

EXHIBIT A-38 (JRB-3)
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OFFICER PLAN

Category	2023 MEASURE	Weighting
Safety	**Employee Safety** (Recordable Incident Rate (70% weighting) & High-Risk Injuries (30% weighting) and Zero fatalities)	**5%**
People	**Culture Index** (Employee Empowerment, Employee Engagement and DEI)	**5%**
Customer	**Customer Experience** - CXi (Survey measuring Customer Experience)	**5%**
Reliability	**Electric Reliability** - SAIDI (System Average Interruption Duration Index)	**5%**
Price	**Affordability** (O&M Savings through Waste Elimination)	**5%**
Environmental	**Methane Emission Reduction** (Reduction of Methane Emissions through replacements of Mains and Services, and through implantation of gas venting protocols)	**5%**
	Total Operational Goals	**30%**
Financial	**Earnings** (Earnings Per Share)	**70%**
	Total Financial Goals	**70%**

NON-OFFICER PLAN

Category	2023 MEASURE	Weighting
Safety	**Employee Safety** (Recordable Incident Rate (70% weighting) & High-Risk Injuries (30% weighting) and Zero fatalities)	**8%**
People	**Culture Index** (Employee Empowerment, Employee Engagement and DEI)	**8%**
Customer	**Customer Experience** - CXi (Survey measuring Customer Experience)	**8%**
Reliability	**Electric Reliability** - SAIDI (System Average Interruption Duration Index)	**8%**
Price	**Waste Elimination** (O&M Savings through Waste Elimination)	**8%**
Environmental	**Methane Emission Reduction** (Reduction of Methane Emissions through replacements of Mains and Services, and through implantation of gas venting protocols)	**8%**
	Total Operational Goals	**50%**
Financial	**Earnings** (Earnings Per Share)	**50%**
	Total Financial Goals	**50%**

2023 Plan Year

	50% Threshold	75%	100% Target	125%	150%	175% Max
Employee Safety (Recordable Incidents Rate, High-Risk Injuries[1], & No fatalities[2])	a.1.65 b. 32	a.1.28 b.30	**a.1.07** **b.27**	a.0.97 b.25	a.0.87 b.23	a.0.77 b.20
Culture Index (Empowerment, Employee Engagement & DEI. Average Results from semi-annual employee survey)	1 of 3 indexes at target	2 of 3 indexes at target	**All 3 indexes at target**	2 indexes at target &1 index above target	1 index at target & 2 indexes above target	3 indexes above target
Customer Experience (Survey Measuring CXi)	66	68	**73**	74	75	80
Electric Reliability (SAIDI in minutes)	185	180	**170**	160	155	150
Waste Elmination[3] (O&M Savings through Waste Elimination)	$30M	$35M	**$45M**	$50M	$55M	$65M
Methane Emission (Reduction through replacement of mains and services)	414MT	436MT	**459MT**	485MT	510MT	551MT

1 High-Risk = Recordable or non-recordable injury caused by a release of high energy
2 A fatality = zero payout for employee safety
3 The Company is not seeking recovery of this measure as it is financial in nature.

OFFICER PLAN

Category	2024 MEASURE	Weighting
Safety	**Employee Safety** (Recordable Incident Rate & High-Risk Injuries (equally weighted) and Zero fatalities)	**5.0%**
People	**Culture Index** (Employee Empowerment, Employee Engagement and DEI)	**5.0%**
Customer	**Customer Experience** - CXi (Survey measuring Customer Experience)	**5.0%**
Reliability	**Electric Reliability** - SAIDI (System Average Interruption Duration Index)	**5.0%**
Price	**Affordability** (O&M Savings through Waste Elimination)	**5.0%**
Environmental	**Methane Emission Reduction** (Reduction of Methane Emissions through replacements of Mains and Services, and through implantation of gas venting protocols)	**5.0%**
	Total Operational Goals	**30%**
Financial	**Earnings** (Earnings Per Share)	**70%**
	Total Financial Goals	**70%**

NON-OFFICER PLAN

Category	2024 MEASURE	Weighting
Safety	**Employee Safety** (Recordable Incident Rate & High-Risk Injuries (equally weighted) and Zero fatalities)	**8.3%**
People	**Culture Index** (Employee Empowerment, Employee Engagement and DEI)	**8.3%**
Customer	**Customer Experience** - CXi (Survey measuring Customer Experience)	**8.3%**
Reliability	**Electric Reliability** - SAIDI (System Average Interruption Duration Index)	**8.3%**
Price	**Affordability** (O&M Savings through Waste Elimination)	**8.3%**
Environmental	**Methane Emission Reduction** (Reduction of Methane Emissions through replacements of Mains and Services, and through implantation of gas venting protocols)	**8.3%**
	Total Operational Goals	**50%**
Financial	**Earnings** (Earnings Per Share)	**50%**
	Total Financial Goals	**50%**

2024 Plan Year

	50% Threshold	75%	100% Target	125%	150%	175% Max
Employee Safety (Recordable Incidents Rate, High-Risk Injuries[1], & No fatalities[2])	a.1.76 b. 25	a.1.23 b.20	**a. 0.96** **b.13**	a. 0.92 b.12	a. 0.86 b.11	a. 0.75 b. 10
Culture Index (Empowerment, Employee Engagement & DEI)	1 index at Target[3]	2 index at Target[3]	**All 3 indexes at Target[3]**	2 indexes at Target &1 Index above Target	1 index at Target & 2 Indexes above Target	3 Indexes above Target
Customer Experience (Survey Measuring CXi)	64	67	**69**	71	75	81
Electric Reliability (SAIDI in minutes)	185	180	**170**	160	155	150
Affordability[4] (O&M Savings through Waste Elimination)	$45M	$55M	**$63M**	$66M	$70M	$74M
Methane Emission (Reduction through replacement of mains and services)	278 MT	290 MT	**302 MT**	335 MT	366 MT	375 MT

1 High-Risk = Recordable or non-recordable injury caused by a release of high energy
2 A fatality = zero payout for employee safety
3 Target = 2023 Q4 actual +2 points (Averaged results from semi-annual employee survey).
4 The Company is not seeking recovery of this measure as it is financial in nature.

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21806
Exhibit No.: A-40 (AMC-2)
Page: 1 of 1
Witness: AMConrad
Date: December 2024

Consumers Energy Company
Target Pay Level Market Analysis
Non-officer

Exempt Jobs:
2023 Market study

Job Family	# of Employees	Avg. Annual Salary	Market Data	Avg. Salary vs.Market
ACCOUNTING	57	$ 119,713	$ 118,774	0.8%
ACCOUNTS PAYABLE & RECEIVABLE	10	$ 110,566	$ 113,107	-2.3%
ADMINISTRATIVE SUPPORT	27	$ 82,377	$ 83,273	-1.1%
ANALYTICS	74	$ 105,353	$ 118,512	-12.5%
ASSET PROCUREMENT	11	$ 111,410	$ 107,617	3.4%
BENEFITS	12	$ 115,376	$ 110,897	3.9%
BUSINESS DEVELOPMENT	16	$ 153,694	$ 172,482	-12.2%
BUSINESS PROCESS & SERVICE QUALITY	66	$ 111,928	$ 122,559	-9.5%
BUSINESS QUALITY MANAGEMENT	43	$ 121,252	$ 116,157	4.2%
BUSINESS STRATEGY & PLANNING	109	$ 139,969	$ 155,648	-11.2%
BUSINESS SYSTEMS ANALYSIS	26	$ 108,516	$ 106,798	1.6%
CAPITAL MARKETS	1	$ 214,968	$ 203,509	5.3%
CHEMICAL	3	$ 141,224	$ 138,126	2.2%
CIVIL	30	$ 120,374	$ 116,758	3.0%
COMMUNICATIONS	20	$ 114,805	$ 113,059	1.5%
COMPENSATION	5	$ 133,897	$ 126,437	5.6%
CONSTRUCTION PROJECT MANAGEMENT	91	$ 152,035	$ 145,579	4.2%
CORPORATE AFFAIRS	29	$ 133,030	$ 130,812	1.7%
CORPORATE GOVERNANCE	4	$ 151,356	$ 160,777	-6.2%
CO-WORKER CONNECTIONS	11	$ 137,856	$ 139,283	-1.0%
CREDIT & COLLECTIONS	1	$ 89,256	$ 98,664	-10.5%
CUSTOMER SERVICE	48	$ 97,034	$ 118,660	-22.3%
CYBER SECURITY	59	$ 133,272	$ 134,382	-0.8%
DATA SCIENCE	31	$ 126,565	$ 133,349	-5.4%
DATABASE ADMINISTRATION	4	$ 130,068	$ 136,222	-4.7%
DESIGN SERVICES	1	$ 99,312	$ 91,355	8.0%
DIVERSITY EQUITY & INCLUSION	7	$ 116,225	$ 114,366	1.6%
DOCUMENTATION & RECORD KEEPING	7	$ 90,239	$ 100,259	-11.1%
ELECTRICAL	190	$ 116,740	$ 121,291	-3.9%
EMPLOYEE RELATIONS	18	$ 134,082	$ 146,942	-9.6%
ENGINEERING & TECHNICAL LEADERSHIP	184	$ 152,808	$ 168,952	-10.6%
ENVIRONMENTAL & EMPLOYEE HEALTH & SAFETY	67	$ 122,660	$ 125,669	-2.5%
ETHICS & COMPLIANCE	37	$ 117,428	$ 112,589	4.1%
EXPLORATION & PRODUCTION OPERATIONS	85	$ 134,818	$ 130,069	3.5%
FACILITIES MANAGEMENT & PLANNING	7	$ 129,250	$ 120,736	6.6%
FINANCIAL CONTROL	12	$ 121,612	$ 115,736	4.8%
FINANCIAL FORECASTING	80	$ 129,339	$ 123,312	4.7%
HR TECHNOLOGY	8	$ 117,119	$ 118,599	-1.3%
INDUSTRIAL	10	$ 114,785	$ 116,382	-1.4%
INFORMATION & TECHNOLOGY LEADERSHIP	61	$ 176,882	$ 188,536	-6.6%
INFORMATION & TECHNOLOGY MANAGEMENT	42	$ 134,603	$ 136,185	-1.2%
INTERNAL AUDIT	8	$ 145,898	$ 143,930	1.3%
INVESTOR RELATIONS	3	$ 140,648	$ 144,942	-3.1%
LABOR RELATIONS	10	$ 114,526	$ 122,415	-6.9%
LABORATORY SERVICES	22	$ 112,214	$ 114,111	-1.7%
LEARNING & DEVELOPMENT	78	$ 105,004	$ 107,389	-2.3%
MACHINE OPERATIONS	6	$ 154,816	$ 142,851	7.7%
MANUFACTURING PLANT MANAGEMENT	5	$ 159,552	$ 167,302	-4.9%
MARKETING GENERALISTS	45	$ 110,123	$ 112,753	-2.4%
MECHANICAL	102	$ 119,942	$ 123,872	-3.3%
ORGANIZATIONAL DEVELOPMENT	11	$ 115,905	$ 123,060	-6.2%
PAYROLL	4	$ 102,894	$ 98,055	4.7%
PHYSICAL SECURITY	10	$ 112,711	$ 123,920	-9.9%
POWER GEN TRANSMISSION & DISTRIBUTION	284	$ 125,126	$ 129,781	-3.7%
PROCUREMENT	53	$ 106,457	$ 107,994	-1.4%
PROGRAM MANAGEMENT	32	$ 127,771	$ 135,002	-5.7%
PROJECT & PROGRAM MANAGEMENT	81	$ 130,136	$ 133,316	-2.4%
PROPERTY MANAGEMENT	1	$ 108,432	$ 116,209	-7.2%
RATES & REGULATION	15	$ 127,956	$ 132,005	-3.2%
REAL ESTATE MANAGEMENT	22	$ 109,952	$ 116,665	-6.1%
REGULATORY AFFAIRS	8	$ 136,152	$ 130,405	4.2%
RELATIONSHIP MANAGEMENT	37	$ 137,901	$ 130,545	5.3%
REPAIR & MAINTENANCE TRADES	20	$ 129,395	$ 128,588	0.6%
RISK MANAGEMENT	26	$ 135,774	$ 132,329	2.5%
SALES & MARKETING	29	$ 139,183	$ 133,779	3.9%
SOFTWARE DEVELOPMENT	17	$ 118,806	$ 123,078	-3.6%
SOFTWARE PRODUCT ENGINEERING	182	$ 125,398	$ 134,835	-7.5%
SUPPLY CHAIN PLANNING & OPERATIONS	46	$ 113,269	$ 111,316	1.7%
SYSTEMS ADMINISTRATION & REPORTING	11	$ 130,667	$ 124,606	4.6%
SYSTEMS ARCHITECTURE	25	$ 144,929	$ 143,783	0.8%
SYSTEMS OPS & PRODUCTION CONTROL	10	$ 110,416	$ 110,771	-0.3%
TALENT ACQUISITION	9	$ 126,773	$ 125,210	1.2%
TAX	14	$ 143,069	$ 131,567	8.0%
TECHNICAL ANALYST	217	$ 108,986	$ 112,293	-3.0%
TECHNOLOGY SUPPORT	17	$ 102,950	$ 111,194	-8.0%
TELECOM & INTERNET	5	$ 114,734	$ 128,597	-12.1%
TREASURY	5	$ 164,309	$ 146,701	10.7%
UTILITIES OPERATIONS	361	$ 132,275	$ 131,725	0.4%
WAREHOUSING & DISTRIBUTION	18	$ 106,536	$ 102,292	4.0%
WORKFORCE ANALYTICS	3	$ 167,512	$ 174,026	-3.9%

Non-Exempt:
2023 Market study

Job Family	# of Employees	Avg. Annual Salary	Market Data	Avg. Salary vs.Market
ACCOUNTING	5	$ 73,715	$ 75,490	-2.4%
ACCOUNTS PAYABLE & RECEIVABLE	81	$ 62,168	$ 61,947	0.4%
ADMINISTRATIVE SUPPORT	50	$ 62,308	$ 53,256	14.5%
ASSET PROCUREMENT	3	$ 64,743	$ 65,382	-1.0%
BENEFITS	3	$ 74,103	$ 72,248	2.5%
BUSINESS PROCESS & SERVICE QUALITY	15	$ 72,882	$ 69,642	4.4%
CREDIT & COLLECTIONS	5	$ 58,885	$ 63,268	-7.4%
CUSTOMER SERVICE	28	$ 60,870	$ 65,995	-8.4%
CYBER SECURITY	15	$ 53,792	$ 67,252	-25.0%
DOCUMENTATION & RECORD KEEPING	14	$ 62,451	$ 63,124	-1.1%
EMPLOYEE RELATIONS	5	$ 65,079	$ 58,977	9.4%
ENGINEERING TECHNOLOGISTS & TECHNICIANS	310	$ 80,717	$ 87,495	-8.4%
ENVIRONMENTAL & EMPLOYEE HEALTH & SAFETY	4	$ 62,634	$ 51,633	17.6%
ETHICS & COMPLIANCE	34	$ 66,151	$ 71,911	-8.7%
FACILITIES MANAGEMENT & PLANNING	2	$ 71,136	$ 66,885	6.0%
HEAVY EQUIPMENT & CONSTRUCTION TRADES	4	$ 59,717	$ 58,293	2.4%
LABORATORY SERVICES	33	$ 70,448	$ 80,861	-14.8%
LEGAL PROFESSIONALS	4	$ 85,628	$ 88,962	-3.9%
MACHINE OPERATIONS	92	$ 69,988	$ 75,895	-8.4%
PAYROLL	14	$ 60,014	$ 59,672	0.6%
POWER GEN TRANSMISSION & DISTRIBUTION	119	$ 66,576	$ 68,390	-2.7%
PROCUREMENT	12	$ 65,986	$ 72,362	-9.7%
PROJECT & PROGRAM MANAGEMENT	149	$ 75,996	$ 81,315	-7.0%
PROPERTY MANAGEMENT	8	$ 59,725	$ 65,352	-9.4%
REGULATORY AFFAIRS	15	$ 68,205	$ 73,363	-7.6%
REPAIR & MAINTENANCE TRADES	24	$ 74,436	$ 71,102	4.5%
SALES & MARKETING	2	$ 73,008	$ 61,351	16.0%
TALENT ACQUISITION	1	$ 65,832	$ 57,989	11.9%
UTILITIES OPERATIONS	71	$ 71,769	$ 74,855	-4.3%
WAREHOUSING & DISTRIBUTION	3	$ 53,054	$ 65,704	-23.8%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Annual Employee Incentive Compensation
($000)

Case No.: U-21806
Exhibit No.: A-41 (AMC-3)
Page: 1 of 2
Witness: AMConrad
Date: December 2024

Line No.	(a) Description	(b) Actual 12-Mos Ended 12/31/2023	(c) Projected 12-Mos Ending 10/31/2026
1	Officer	613	560
	Labor	613	560
	Material	0	0
	Contractor	0	0
	Other	0	0
	Business Expenses	0	0
2	Non-Officer	1021	986
	Labor	1021	986
	Material	0	0
	Contractor	0	0
	Other	0	0
	Business Expenses	0	0
3	Total "Annual Incentive" O&M Expenses	1634	1546
	Labor	1634	1546
	Material	0	0
	Contractor	0	0
	Other	0	0
	Business Expenses	0	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Annual Incentive
($000)

Case No.: U-21806
Exhibit No.: A-41 (AMC-3)
Page: 2 of 2
Witness: AMConrad
Date: December 2024

Line No.	Description	(a)	(b) Actual 12 Mos Ended Dec 31, 2023	(c) Base O&M for Merit & Inflation 12 Mos Ended Dec 31, 2023	(d) Merit & Inflation 12 Mos Ending Dec 31, 2024	(e) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	(f) Merit & Inflation 12 Mos Ending Dec 31, 2025	(g) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	(h) Merit & Inflation 10 Mos Ending Oct 31, 2026	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending Oct 31, 2026
					(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	Officer		613	613	20	536	13	548	11	(97)	560
	Labor		613	613	20	536	13	548	11	(97)	560
	Material				0		0		0		0
	Contractor				0		0		0		0
	Other				0		0		0		0
	Business Expenses				0		0		0		0
2	Non-Officer		1,021	1,021	33	944	23	967	20	(110)	986
	Labor		1,021	1,021	33	944	23	967	20	(110)	986
	Material				0		0		0		0
	Contractor				0		0		0		0
	Other				0		0		0		0
	Business Expenses				0		0		0		0
3	Total "Annual Incentive" O&M Expenses		1,634	1,634	52	1,480	36	1,515	32	(207)	1,546
	Labor		1,634	1,634	52	1,480	36	1,515	32	(207)	1,546
	Material		0	0	0	0	0	0	0	0	0
	Contractor		0	0	0	0	0	0	0	0	0
	Other		0	0	0	0	0	0	0	0	0
	Business Expenses		0	0	0	0	0	0	0	0	0

Notes

	12-Mo Ending 2024	12-Mo Ending 2025	10-Mo Ending 2026
Annual inflation rates per Company witness Rayl	3.2%	2.4%	2.5%
Number of months in the period	12	12	10
Pro-rated inflation rate	3.2%	2.4%	2.1%

Natural Gas Delivery Plan

2025 – 2035

Revision 5

Date: December 1, 2024

Document Owner: Executive Director – Gas Strategy & Projects

2025 – 2035

Natural Gas Delivery Plan

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Acronyms

AGA – American Gas Association

AMI – Advanced Metering Infrastructure

AMR – Automated Meter Reading

API – American Petroleum Institute

ARMA – Association of Records Managers and Administrators

Bcf – Billion Cubic Feet

BYOD – Bring Your Own Device

C&I – Commercial and Industrial

CAGR – Compounded Annual Growth Rate

CARE Program - Consumers Affordable Resource for Energy

CE – Consumer's Energy

CG – City Gate

CIP – Critical Infrastructure Protection

CO2e – The number of metric tons of CO2 emissions with the same global warming potential as one metric ton of another greenhouse gas

CoE – Center of Excellence

DIMP – Distribution Integrity Management Program

DR – Demand Response

ECAP – Enterprise Corrective Action Program

ECO – Enterprise Contractor Oversight

EIRP – Enhanced Infrastructure Replacement Program

ETR – Estimated Time of Restoration

FT – Firm Transport

GCM – Gas Communication Module

GCR – Gas Cost Recovery

GIS – Geographic Information System

GRN – Gamma-ray Neutron

GSMS – Gas Safety Management System

GTIE – Gas Technical Information Excellence

HCA – High-Consequence Area

HP – High Pressure

hp – Horsepower

IaaS – Infrastructure as a Service

IT – Information Technology

LAUF – Lost and Unaccounted for (gas)

LDCs – Local Distribution Companies

LFERW – Low Frequency Electric Resistance Welded

MCA – Moderate Consequence Area
MMbtu – Million British Thermal Units
MMCFD – Million Cubic Feet per Day
MP – Medium Pressure
MPSC – Michigan Public Service Commission
NERC – North American Electric Reliability Corporation
O&M – Operations and Maintenance
OTSRA – Operational Technology Security Reference Architecture
PAAS – Platform as a Service
PHMSA – Pipeline & Hazardous Materials Safety Administration
PIPES – Pipeline Inspection, Protection, Enforcement, and Safety Act
Plan – Natural Gas Delivery Plan
psi – Pounds Per Square Inch
psig – Pounds Per Square Inch Gauge
PSMS – Pipeline Safety Management System
RCV – Remote-Control Valve
RM – Regulated Diaphragm Meter
RORs – Random Outage Rates
RNG – Renewable Natural Gas
RP – Recommended Practice
RTU – Remote Terminal Units
SaaS – Software as a Service
SEA – Statewide Energy Assessment, an MPSC report dated September 11, 2019 (Case No. U-20464)
SCADA – Supervisory Control and Data Acquisition
SCC – Stress Corrosion Cracking
SMB – Small Business, as described in the Company's gas demand response pilot
SP – Standard Pressure, also referred to as utilization pressure
TC – Top Connect Meter
TCF – Trillion Cubic Feet
TED-I – Transmission Enhancements for Deliverability and Integrity
TOD – Transmission Operated by Distribution
TP – Transmission Pressure
USM – Ultrasonic meters
VSR – Vintage Service Replacement
WC – Inches of Water Column

Revision History

Revision	Approval Date	Revision Description
0	12/16/2019	Initial Document
1	12/11/2020	First Revision
2	12/01/2021	Second Revision
3	12/01/2022	Third Revision
4	12/01/2023	Fourth Revision
5	12/01/2024	Fifth Revision

I. Executive Summary

A. Introduction

Consumers Energy Company's ("Consumers Energy" or the "Company") natural gas system serves Michigan safely, reliably, and affordably, providing energy for residential and business space heating, water heating, meal preparation, grain drying, industrial processes, and electricity generation.

Technological changes and environmental concerns create a time of unprecedented change in the energy industry. Consumers Energy embraces these challenges as opportunities for the coming decades by carefully planning for the future.

This annually updated *Natural Gas Delivery Plan* ("NGDP" or the "Plan") maps the Company's vision to safely serve customers with natural gas for the next 10 years. The Company's Commission-approved *Clean Energy Plan,* along with the *Electric Distribution Infrastructure Investment Plan* chart the path for its electric business.

Natural gas is fundamental for keeping customers warm in colder months, and delivering reliable and affordable energy for Michigan's businesses and high heat industrial processes. The Plan is founded on the Company's commitment to providing safe, affordable, reliable, and increasingly clean natural gas for Michigan.

The Plan reflects the Michigan Public Service Commission's ("MPSC" or the "Commission") previous Orders in which Consumers Energy received insights on the natural gas system through the 2019 Statewide Energy Assessment ("SEA"), and also from the outcome of the Company's latest gas rate case, Case No. U-21490.

In updating this Plan, Consumers Energy weighed input from peer gas utilities, industry experts, MPSC staff, and other key external stakeholders to best understand how to serve customers and the State of Michigan.

The Plan outlines the next decade of investments in natural gas infrastructure, planning for natural gas supply and demand, and operational changes in accordance with the industry best practice of a Pipeline Safety Management System ("PSMS") protocol from the American Petroleum Institute ("API") Recommended Practice ("RP") 1173, or as Consumers Energy identifies it, as an expanded Gas Safety Management System ("GSMS").

Four key external drivers are critical to the natural gas business future:

External Drivers	Key Factors
Safety	Employees, customers, and the public must safely co-exist with natural gas assets. That means Consumers Energy must anticipate risks and mitigate them proactively.
Increasing Regulation	Safety incidents across the nation's gas infrastructure and changing policies regarding carbon and methane emissions continue to present new rules and increased regulatory oversight at the state and federal levels.
Changing Supply and Demand Patterns	The plan anticipates domestic natural gas supply growth adequate to meet increases in long-term demand, enabled by mid-stream investment. This will limit real commodity price increases over the longer term as the North American natural gas market expands.
Environmental Focus	The impact of natural gas use on climate change through carbon emissions and methane emissions is becoming a focal point of environmentally conscious customers, regulators and other stakeholders as coal-based emissions from electric generation continue a downward trend.

The Plan documents the Company's analysis and stakeholder input on these drivers and is built on the following four objectives that provide flexibility to adapt and perform as an energy provider that customers, regulators, and the people of Michigan can count on.

Objectives	Natural Gas Delivery Plan Outcomes
Safe	Ensure the safety of customers and the communities we serve by maintaining pace of retiring vintage materials throughout the gas system to reduce risk of incidents that could adversely affect the public, customers, and employees or contractors.
Reliable	Improved reliability, resilience, and system flexibility in preparation for more variable climate patterns, variable supply sourcing options, and regulatory and maintenance activities, with improved equipment reliability.
Affordable	Stable, predictable, and reasonable total bills, including gas asset investment costs, the commodity costs of natural gas, and costs to support additional regulatory requirements.
Clean	Reduction of the Company's and its customers' contribution to climate change through gas system decarbonization. Gas system decarbonization will include options for reducing methane emissions across the delivery system and investment in renewable natural gas to help customers offset emissions associated with natural gas use.

Throughout the development of this Plan, the gathering of stakeholder input, and the SEA report, the Company considered the long-term future of the natural gas business along with the potential outcomes of current trends. The resulting plan informs shorter-term activities and regulatory filings to best serve customers.

The Plan will guide the Company's actions today, and provide an evolving framework to monitor initial assumptions, gather new stakeholder input, adjust to potential new expectations for the future, and remain on a transparent pathway to a safe, reliable, affordable, and clean natural gas system for Michigan.

B. Consumers Energy's Natural Gas System

The Company's natural gas system serves approx. 1.8 million customers across Michigan's lower peninsula and is comprised of four Asset Classes: Storage, Compression, Transmission, and Distribution.

Natural gas follows this flow through the Company's system in the following way:

- Consumers Energy receives gas supply into its transmission pipelines that operate between 400–1,185 pounds per square inch ("psi"), which are considered transmission pressure ("TP") lines.
- Compressor stations are used to increase the pressure of natural gas for transportation in the system and for withdrawal from or injection into storage fields.
- City gate stations move gas from the transmission pipeline system to feed distribution mains that operate as high-pressure ("HP") lines between 60–400 psi and medium pressure ("MP") lines between 2-60psi.
- Gas is then routed throughout the distribution system and delivered to residential and business customers that operate on MP lines, and standard-pressure ("SP") lines at less than 1 psi.

An illustration of a typical natural gas system layout is shown in Figure 1 with system statistics listed in Appendix A.

Key attributes and focuses across the primary asset classes include the following:

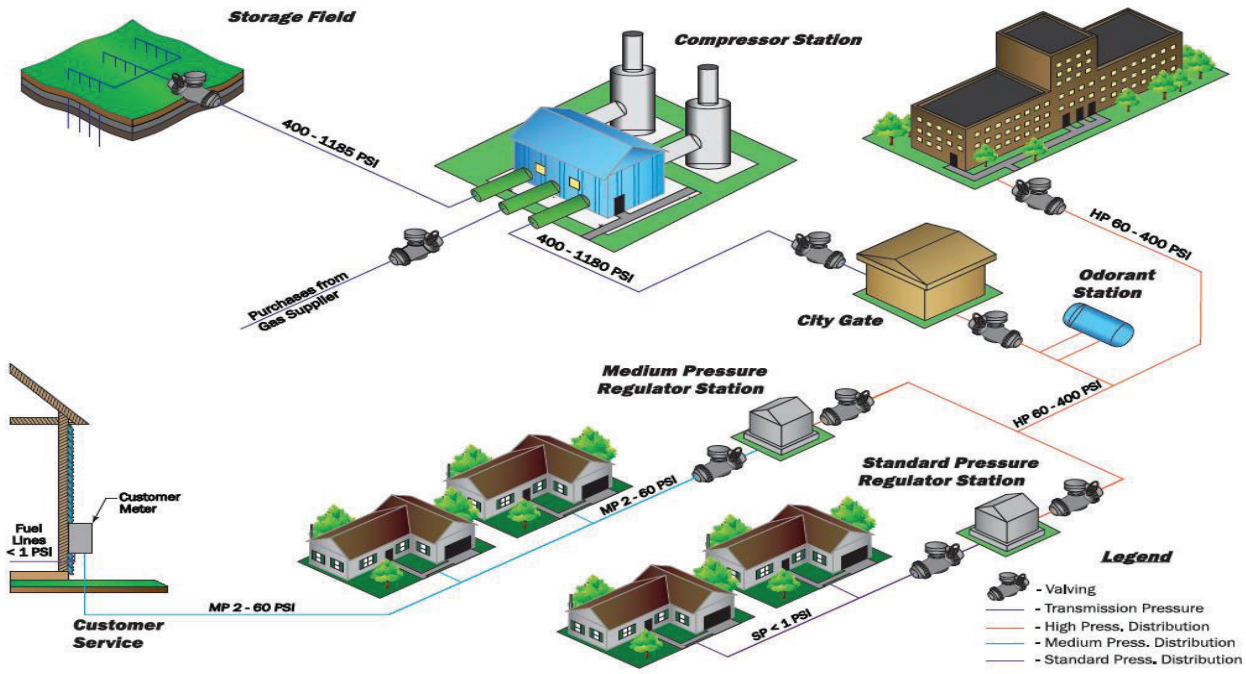
Storage: Storage assets play an important role in customer affordability and system resiliency. The Plan calls for execution of well inspection, well rehabilitation, increased remote well monitoring, and strategic new well drilling to optimize storage fields. This work increases efficiency and resiliency while lowering risk and cost.

Compression: Gas compression assets inject gas into and withdraw gas from storage fields, inject gas onto the Company's system from interstate pipelines, and boost transmission and distribution gas pressures seasonally. The Plan outlines how the compression fleet is optimized, which may include the addition of certain equipment for reliability, and retirement of antiquated compression assets.

Transmission: Gas transmission pipelines are the 'expressways' of the gas system, transmitting large quantities of gas at high pressures in large diameter pipes ranging from 4 inches to 36 inches. The Company's goal is to meet the capacity needs of Michigan as well as to optimize the transmission system in terms of age, materials, and technology to ensure public safety.

Distribution: The distribution system includes some of the Company's oldest facilities that are situated closest to customers. Therefore, replacing aging infrastructure to reduce risk and expanding remote monitoring in this area is a critical focus.[1]

Figure 1: Typical Natural Gas System Layout



[1] U.S. Department of Transportation, Gas Distribution System Annual Report for Calendar Year 2023, submitted 03/12/2024.

C. Pipeline Supply

Consumers Energy's system accesses seven interstate pipelines and one major intrastate pipeline.

This interconnectivity provides diverse access to supply from Appalachia, the Rockies, Canada, the Gulf Coast, and Mid-Continent production basins.

Interstate pipeline supply into Consumers Energy's system generally ranges from 600 million cubic feet per day ("MMCFD") to 1,400 MMCFD. Overall, pipeline supply is required to fill storage in the summer season while meeting customer demand.

A mix of pipeline supply and storage supply withdrawals are used during the winter season to ensure reliability and affordability to customers.

D. Operational Capabilities

The Plan requires essential operational capabilities in the areas of people, process, and technology to ensure 10-year goals and outcomes are achieved.

People

Consumers Energy is focused on ensuring the Company has the right people, with the right skills and culture, at the right place and time. To deliver on this vision, the Company is focusing on creating the right employee experience, attracting and retaining qualified and talented candidates, ensuring the right skills are there for the right jobs, and make certain a diverse, equitable, and inclusive workforce.

Process

To ensure the Company continues to best position itself for the future uncertainties, it will also assess operating models (e.g., governance, roles, responsibilities, structure, ways of working) and will adjust as required. Primary operating models include the CE Way and Gas Safety Management Systems. See *Operational Capabilities* below for further discussion.

Technology

To fully enable the goals and outcomes of the Plan, the Company invests in digital capabilities to keep assets safe, secure, operating, and maintained. Key technologies involve monitoring capabilities, improving data analytics, physical and cyber security upgrades, and incorporating more predictive capabilities. See *Technology* below for planned digital investments.

E. Climate Goals

The Company is committed to reducing fugitive methane and carbon emissions from the delivery system, while also better understanding the emissions from the natural gas upstream suppliers and end-use customers. This commitment is demonstrated in the Company's Scope 1 net zero methane emissions goal by 2030 and Scope 3 customer net zero carbon emissions goal by 2050. These goals align with the MI Healthy Climate Plan and Federal Executive Order ("EO") 14008.

Please see *Gas System Decarbonization* for additional discussion.

II. Consumers Energy Natural Gas Delivery Plan

A. Vision Statement

The Company's vision is to ***deliver safe, reliable, and affordable natural gas to our customers while transforming the system to deliver cleaner fuels for a decarbonized and equitable future.***

B. Objectives

The Plan has four objectives to guide future investment decisions across the full system of storage, compression, transmission, and distribution. These objectives are: Safe, Reliable, Affordable, and Clean. Consumers Energy will include energy and environmental justice as an additional key objective in future revisions.

These objectives help prioritize investment decisions based on factors such as risk, cost, and various impacts to the customer to ensure successful outcomes for the Plan.

The Plan reflects a thorough analysis of the natural gas system, the natural gas commodity market, trends and practices across the industry, as well as customer trends. Consumers Energy intends to routinely review the inputs and assumptions that led to the creation of the Plan, update it as appropriate, and continue to share the Company's vision with stakeholders across Michigan.

1. SAFE

The **safety** of employees, customers, the public, and the system is the Company's top priority. It is critical the Company protects not only customers, but the communities served. To ensure a safe system, the following focus areas remain paramount:

- Reduce system risk to ensure the safety of the community and our customers.
- Focusing on process enhancements to improve gas system safety.
- Enhancing reliability and expanding 24/7 monitoring of the system.
- Modernizing the entire natural gas system, including the remediation of distribution and transmission assets, and replacing higher-risk vintage distribution mains and services.
- Using remote control, real-time data monitoring, probabilistic risk modeling to better identify safety concerns across all asset classes.

The Company is also placing an emphasis on **best practices in GSMS** (API RP 1173), and **records management**. Consumers Energy will use operational metrics to measure factors spanning the safety of personnel, assets, processes, as well as physical and cybersecurity.

2. RELIABLE

Consumers Energy creates and maintain a **reliable** system through dependable assets, measured through metrics such as gas flow deliverability, and total system resilience. The Company issues a **resilient storage and market supply plan for peak demand days**, and proactively balances peak customer demand primarily with storage and use of EWR.

Considering the 2019 Ray incident, the SEA, and the need to ensure **energy delivery resiliency and system reliability**, the Company assesses the system's ability to adapt to winter single failures, and the agility needed to respond to potential changes in the natural gas market environment and connected systems.

The American Gas Foundation[2] provides definitions for both resilience and reliability as follows:

- **Resilience** is defined as ***a system's ability to prevent, withstand, adapt to, and quickly recover from a high-impact, low-likelihood event such as a major disruption in a transmission pipeline.***
- **Reliability** is defined as ***a system's ability to maintain energy delivery under standard operating conditions, such as the normal fluctuations in demand and supply.***

The Company agrees with those definitions and considers both reliability and resilience critical to the Company and its customers. This shows the value of Consumers Energy having an underground transportation network that is highly reliable and resilient in delivering energy without interruption.[3]

In addition, the Company assesses gas system resiliency needed due to potential climate change risk, as part of our publicly available *Climate Change Risk, Vulnerability and Resiliency Report*[4].

3. AFFORDABLE

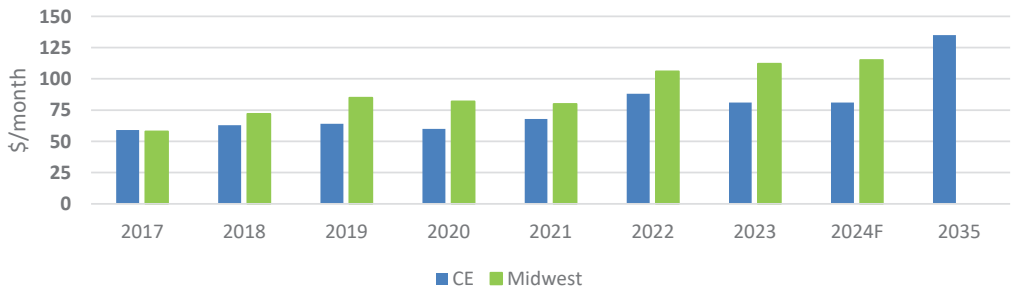
There is consistent **focus on delivering affordable** gas to customers with competitive and predictable prices. Consumers Energy analyzes average customer bills (total cost and cost per Mcf) against the Midwest average to manage total costs to the customer.

Customer bills are expected to increase over the next several years due to inflation, capital investments, and market forces. **The Company has a responsibility to keep bills as low as reasonably possible for all customers** and will work with customers to mitigate these rising costs as follows:

- The Company helps customers use less natural gas by providing energy-efficient products and resources. This includes winterization kits for homes and businesses and promoting customer assistance available.
- The Company offers energy waste reduction choices for all classes of natural gas customers.
- The Company offers tariff options to customers to create additional benefit of enabling decreased transportation costs for C&I customers during peak times.
- The Company is committed to supporting low-income customers through the Consumers Affordable Resource for Energy ("CARE") Program.

Figure 2 shows customer bill history in blue against the Midwest average and the average monthly residential bill per year forecast over the next 10 years.

Figure 2: Average Monthly Residential Customer Bill History and Forecast



[2] American Gas Foundation. Building-a-Resilient-Energy-Future-Full-Report_FINAL_1.13.21.pdf (gasfoundation.org)

[4] *Climate Change Risk, Vulnerability and Resiliency Report*

As shown in Figure 2, the average monthly bill increased approximately 5% year over year since 2017. This is below the Midwest average growth rate of approximately 10%. Moving forward, the residential bill is expected to grow approximately 5% per year through 2035.

The Company also ensures commodity costs are in line with market conditions. It will invest in the long-term infrastructure investment requirements needed to ensure safe, reliable, and compliant gas delivery while also maintaining competitive, affordable, and predictable customer bills.

4. CLEAN

Consumers Energy is committed to Michigan, its natural resources, and a sustainable climate for generations to come.

The Company's proposed *Clean Energy Plan*, as filed with and approved by the MPSC in June 2022, proposes to end coal use by 2025, increases renewables and energy efficiency, and meets customer needs with 90 percent clean energy resources. The *Clean Energy Plan* puts the Company on a trajectory to meet its net zero carbon emissions goal for the electric system by 2040.

In support of Michigan's Healthy Climate Plan 2050 carbon neutrality goal, as well as other national and international efforts, the Company is evaluating changes to the natural gas business to reduce, offset, and replace methane and carbon emissions, including customer end-use. The primary "clean" outcome is to achieve net-zero methane emissions by 2030, which is a first step and important component of the decarbonization plan.

Additionally, the Company committed in 2022 to expand on its clean energy goals to include all emissions, including upstream suppliers and downstream customers, that are part of the entire gas delivery system to be carbon neutral by 2050. Which includes an interim goal of 20% reduction in customer emissions by 2030. The initial step towards reducing customer end-use emissions is the launch of the MI Clean Air carbon offset voluntary program for residential, commercial, and industrial customers.

Key pathways to achieve net zero carbon emissions by 2050 include: energy waste reduction ("EWR"), carbon offsets, renewable natural gas ("RNG"), and potentially other decarbonization technologies in the future (e.g., hydrogen, carbon capture sequestration, electrification, geothermal, etc.). In 2024, the MI Clean Air Program was expanded to offer customers a voluntary option to offset emissions associated with natural gas use through renewable natural gas.

C. Alignment with Objectives, Goals, and Outcomes

The investments described in this Plan are necessitated by federal and state regulatory requirements, ensure safety, reliability, and the environment, while keeping customer bills affordable and predictable.

The Company will track these—as well as short-term operational metrics—by measuring and analyzing leading and lagging indicators, displayed below in Figure 3.

As the Company evolves its strategy, energy and environmental justice (EEJ) will be a meaningful component of how the Company plans investments. See *Operational Capabilities* below for how the Company is assessing EEJ and how the Company will ensure a clean and equity energy future for all customers and all communities.

Figure 3: Natural Gas Delivery Plan Objectives, and Outcomes

Objective	Delivery Plan	Outcome	Year Ending 2024	2030 Target
Safe	Achieve zero incidents by replacing high-risk materials in service, distribution, and transmission	Implement probabilistic risk model	40%	100%
		Sustain GSMS maturity level	3.37	≥4.0
Reliable	Ensure supply reliability and system resilience by improving fleet reliability, leveraging storage, and using multiple interconnections	Maintain Gas Flow Deliverability	95%	95%
		Increase Resilience	88.7%	>91.5%
Affordable	Improve value through stable and predictable total bill growth	Average monthly residential bill < Midwest Average	+5.8%	<Midwest average
		Customer Satisfaction Index	1st quartile	1st quartile
		Increase Energy Waste Reduction	1.1%	1% year over year
Clean	Reduce gas system carbon equivalent emissions by eliminating methane leaks and implementing various technologies for gas system decarbonization	Reduce Scope 1 system methane emissions from 2012 baseline	30% reduced	100% reduced
		Reduce Scope 3 customer carbon emissions from 2022 baseline	2%	20%

III. Consumers Energy Natural Gas Supply

A. Overview of Natural Gas Market

Over the past 15 years, advancements in unconventional drilling production methods alongside increased mid-stream investment turned the U.S. into a net exporter of natural gas.

The U.S. natural gas market continues to expand while accommodating changing producer priorities and global influences as export demand matures, with 2024 U.S. consumption estimated to achieve an all-time high of 33 Tcf. Over the long-term, natural gas prices are projected to remain affordable as U.S. natural gas production is viewed as capable of efficiently meeting demand growth due to favorable U.S. oil and natural gas shale production economics, market transparency, and a resilient interconnected interstate natural gas transportation system.

Michigan was well positioned to benefit from growth in shale production over the last 15 years. The largest U.S. shale production basin is in the nearby Marcellus and Utica Appalachian formations primarily in Ohio, Pennsylvania, and West Virginia[5]. Appalachian production accounted for approximately one third of the U.S. production in 2024 and has applied downward pressure to regional natural gas prices as local supply volumes have increased over time in concert with Michigan's U.S. leading natural gas storage capacity.

Amid this environment, Consumers Energy is well positioned for affordable, reliable, and diverse natural gas supply. Beyond ample regional supply, the Company's natural gas system has access to seven interstate pipelines and the most prolific natural gas production basins in the country, Canadian supply, a major intrastate pipeline interconnect and Michigan production.

Consumers Energy's class leading storage facilities, flexible interconnected system, and access to low-cost regional supply provide competitive advantage below benchmark commodity prices.

B. Consumers Energy's Natural Gas Supply Plan

The Company's GCR supply plans are detailed in a separate regulatory filing and are updated annually and include procurement details on the advantage Consumers' system provides to customers.

- Foundationally, the Company's GCR Plan seeks to lock in historically lower summer natural gas prices using storage investments to minimize winter procurement and associated price and supply risks.
- Typically, the Company procures about 75% of its GCR supply requirements in the summer months for injection into storage fields to meet winter GCR customer demand. Winter GCR sales constitute about 75% of total GCR annual sales. On the coldest days, storage can provide up to 80% of total customer demand, with the balance of demand served by the fixed (ratable) flowing pipeline supply.
- Storage provides price stability, lowers supply related risks, and generally lowers commodity costs in the winter months. It also provides system flexibility and resilience to enable reliable and timely delivery services by efficiently balancing variable customer load throughout the day.
- The Company, in conjunction with DTE Gas, plans to construct a transmission interconnect in 2025 between the two companies that will diversify the supply source, improving resiliency for both companies. This Project is further described below in the *Transmission Plan* section.

[5] Shale natural gas production in the Appalachian Basin sets records in first half of 2021 - U.S. Energy Information Administration (EIA)

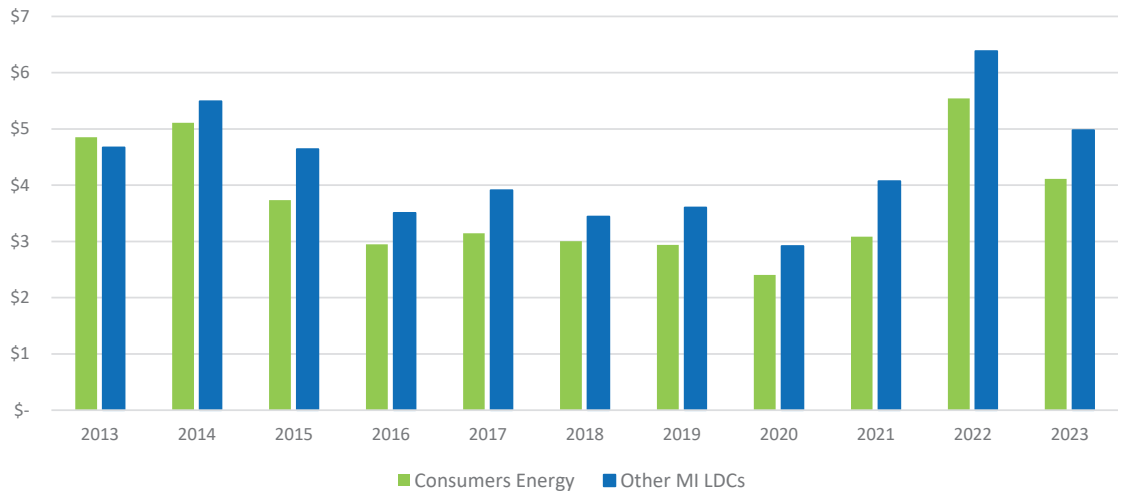
- The increase in regional and U.S. natural gas production and Midwest interstate pipeline capacity and interconnectivity transformed the area's supply fundamentals, substantially increasing the supply available at the Company's system interconnects, i.e., city gate supply. City gate supply has proven to be a reliable, resilient, and least-cost alternative to upstream purchases using interstate pipeline capacity. In the past, higher levels of transportation contracts were used to reduce supply availability, price volatility, and system deliverability risks.
- Over the past several decades, the Company made investments in its transmission pipe, storage, and compression assets to increase the deliverability of storage assets and overall system flexibility capable of balancing customer demand and less flexible pipeline supply. These investments along with the increase in regional supply have reduced the reliance on fixed cost transportation contracts born solely by the GCR customer class to about $43 million per year.
- The Company's GCR Plan also includes provisions leveraging system investment capacity and flexibility to engage in value-added transactions based on emergent market opportunities to capture favorable price arbitrage economics lowering net GCR commodity costs for our customers. Further provisions allow for fixed price purchases of customer supply requirements when markets prices are at historically low levels.

The Company's system investments and commodity supply plan minimize natural gas price volatility and supply risk for customers. This has resulted in GCR customer commodity costs often lower on average than other Michigan regulated gas utilities over the past decade.

To ensure affordability, Consumers Energy will continue evaluating both GCR commodity and investment costs when considering the total delivered price of gas the customer pays.

Figure 4 shows the Company's annual average GCR price when compared to the average of the other Michigan Local Distribution Companies (LDC's) through 2023.

Figure 4: Average GCR Billing Factor Price for Consumers Energy and Other Michigan LDCs[6]



[6] https://www.michigan.gov/documents/mpsc/gasrates_592543_7.pdf

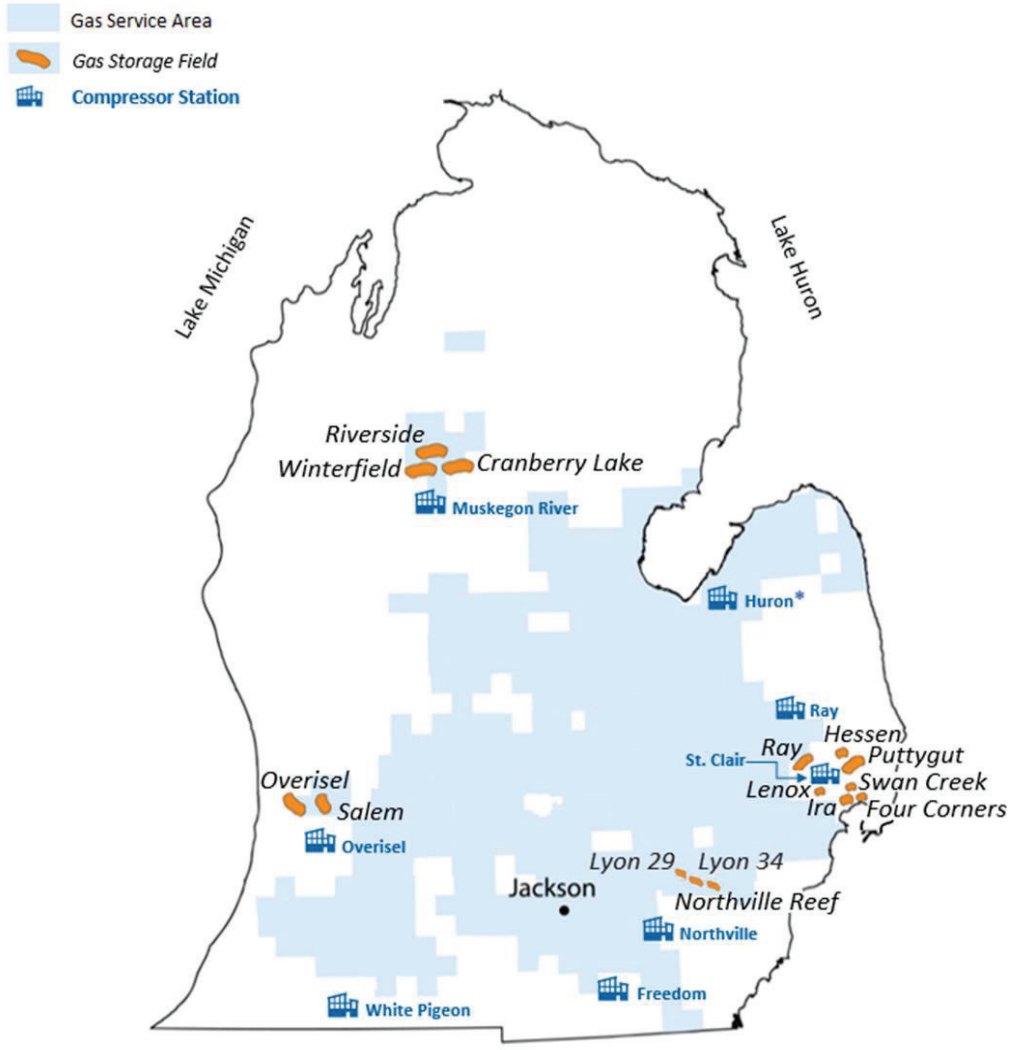
IV. Asset Classes

A. Storage Asset Plan

As a northern peninsula state, Michigan is geographically disadvantaged but geologically advantaged from a natural gas perspective.

Consumers Energy has 15 underground natural gas storage fields tapping into depleted hydrocarbon reservoirs deep underground through approximately 808 wells that tie into the Company's gas system. Figure 5 illustrates the location of the storage fields in relation to the compression assets.

Figure 5: Map of Michigan with Storage Field and Compressor Station Locations



The Company's storage assets are used to inject and withdraw natural gas to meet Michigan's winter energy needs as a safe, reliable, resilient, and low-cost alternative to traditional firm interstate transportation capacity. **This storage capacity provides customer value** by enabling the Company to purchase gas at lower prices in the summer, and provides the capability to quickly adapt to customer demand and operational changes throughout the day, week, and month.

The flexibility of storage provides end user/transport suppliers, Gas Customer Choice suppliers, and the Company the **ability to purchase gas in ways that provide economic benefits while ensuring supply adequacy during periods of high demand**.

The storage fleet plays an important role during extreme weather situations and emergent operational changes by providing **quick access to high volumes of gas** that are geographically close to Michigan's demand centers at summer versus peak use pricing. Michigan's winter demand peaks are due to residential heating and therefore significantly affected by weather conditions. These demand peaks often coincide with increased electric generation demand.

Geographical **proximity of gas storage to customer load provides a systemic advantage** during the extremely cold winters. Growth of gas-fired generation to offset the retirements of coal-fired generation generally adds to the variation and peak needs during a day. For this reason, it is critical to maintain a safe and reliable storage asset portfolio for Michigan's electric supply.

All the Company's gas storage fields are accessed through vertical or horizontal wells and are connected to compressor stations by storage pipelines. Improvements in field performance depend on the performance of the entire integrated facility since the gas flows through to get to the transmission system.

The Company's efforts to optimize overall field performance through multiple efforts (i.e., new wells, well rehabilitation, strategic plugging, etc.) are **leading to better performing fields that allow for a more resilient overall system.** Since 2018, the Company reduced the number of storage wells, becoming more efficient and safer, while maintaining relatively consistent levels of working gas and capabilities. This provides quicker access to large quantities of natural gas than incremental pipeline supply purchases.

The storage fields provide approximately 154 Bcf of cyclic design capacity known as Working Gas. In addition to the natural gas cycled annually for customer use, a base level remains in place to ensure the field is adequately pressurized.

1. STORAGE ASSET CLASS 10-YEAR FOCUS

- Optimize aging storage asset infrastructure to lower operating cost, maintain deliverability, and decrease emissions points.
- Assess wells to determine if they are underperforming.
- Optimize storage asset risk, in alignment with PHMSA requirements, and performance by coordinating remediation, plugging and decommissioning underperforming wells, maintaining storage capability with new and more efficient wells, and updating existing storage equipment and lateral pipelines.
- Increase cycling of peaker fields for cold weather events as prescribed GCR filings.
- Invest in digital solutions for increased storage well monitoring.

2. STORAGE ASSET MANAGEMENT

The Company's gas storage fields are segmented into baseload, intermediate, and peaking fields to serve different needs depending on daily, monthly, and seasonal demand deliverability requirements.

Storage fields in the system are used in three ways:

- ***Baseload*** storage fields run daily during the winter to meet base level demand and provide more efficient supply paths to the natural gas system further away from pipeline supply interconnects.
- ***Intermediate*** storage fields run during longer periods of higher demand.
- ***Peaker storage fields*** run during the extreme hours and days when demand changes quickly.

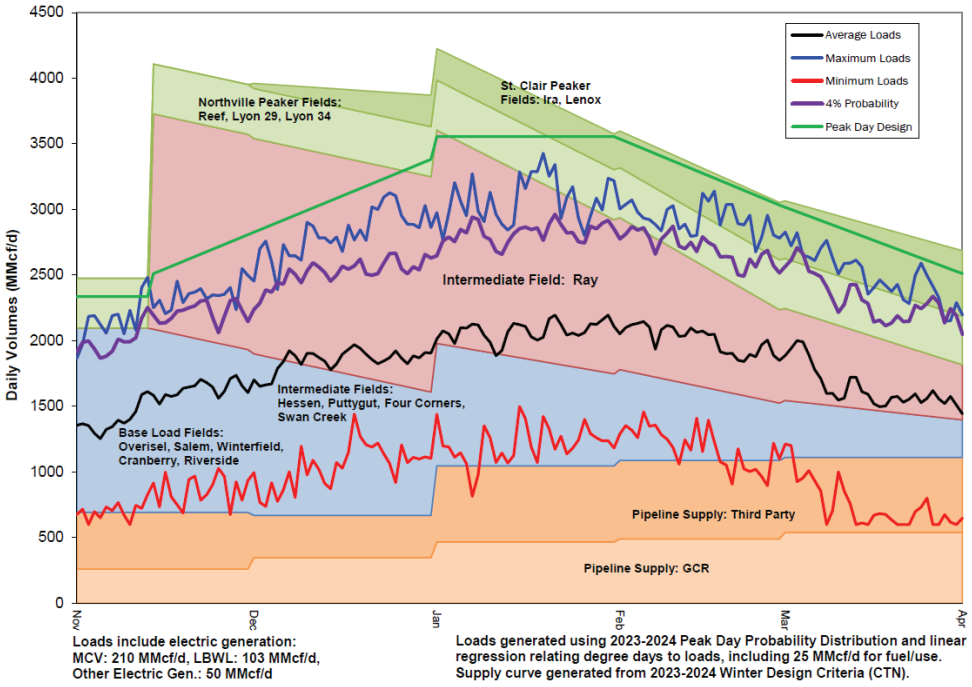
Table 1: Storage Field Types, Names, Working Gas, Base Gas, Total Gas Volumes, Number of Wells

Type	*Storage Field Name*	*Working Gas Volume (Bcf)**	*Base Gas Volume (Bcf)**	*Total Gas Volume (Bcf)**	Number of Wells
Base	Winterfield	25.30	47.00	72.30	249
	Overisel	25.50	27.50	53.30	152
	Salem	11.60	18.90	30.50	71
	Cranberry	11.00	17.20	28.20	129
	Riverside	1.50	7.50	9.00	51
Intermediate	Hessen	13.50	3.48	16.98	24
	Puttygut	9.50	5.10	14.60	24
	Four Corners	2.39	1.39	3.78	6
	Swan Creek	0.42	0.23	0.65	1
	Ray	48.10	17.27	65.37	62
Peaker	Ira	2.00	4.25	6.25	15
	Lyon 29	1.23	0.95	2.18	3
	Lenox	1.20	2.03	3.23	11
	Lyon 34	0.70	0.66	1.36	5
	Northville Reef	0.50	0.72	1.22	5
***NOTE:** All gas volumes are in MMcf at 14.73 psi dry pressure base.					

Each storage field has unique reservoir characteristics, including different cyclic capacities. This includes the ability to efficiently maximize storage utilization through leveraging the design and mechanical condition of the wells, transmission pipeline, attached compressor station, and system operating conditions such as weather. Additionally, supply can be sourced from storage to offset normal conditions in the event of high storage inventory.

Figure 6 displays the wide variety of customer demand that is considered as represented by the vertical space between the lime green (Minimum Loads) and the green (Design Peak Day) flows. Storage effectively allows for the variation in customer load as the Company can shut in or dispatch storage supply as needed throughout the day.

Figure 6: Daily Winter Design Capacity and Loads



The above supply curves (daily volumes) use assumptions, and therefore Figure 6 helps the reader conceptually understand how the Company's storage fields are used based on their capabilities.

Delivery rate is the flow rate of gas per time (usually daily) that a specific storage field or well can provide. Fields designated as **peakers,** such as Lyon 29, typically have high per-well delivery rate, but fewer overall wells, while **baseload** fields, such as Winterfield, tend to have higher well counts but lower overall deliverability on a per-well basis.

Fields designated as **intermediate** fields also have relatively high deliverability characteristics as well as significant cyclic capacity that makes them suitable for both peaking and baseload operations.

Storage field deliverability is directly tied to the amount of gas within them, and as gas is removed from them to supply customers, their deliverability rate capability (daily volumes) decreases.

Consumers Energy's historical storage usage follows a similar annual pattern: generally steady injection from April to October and withdrawal from November to March.

Injection and withdrawal plans consider the individual field capability and inventory as well as capability of the natural gas system and customer demand. Some fields take longer to fill or empty depending on their geology, inventory, and the use of compression. Their capability for accepting gas decreases as they are filled, and as field inventory decreases, the ability to provide supply decreases.

During the withdrawal season, baseload fields provide early winter gas, followed by intermediate fields, such as Ray, and peaking fields when the temperatures drop and customer demand increases.

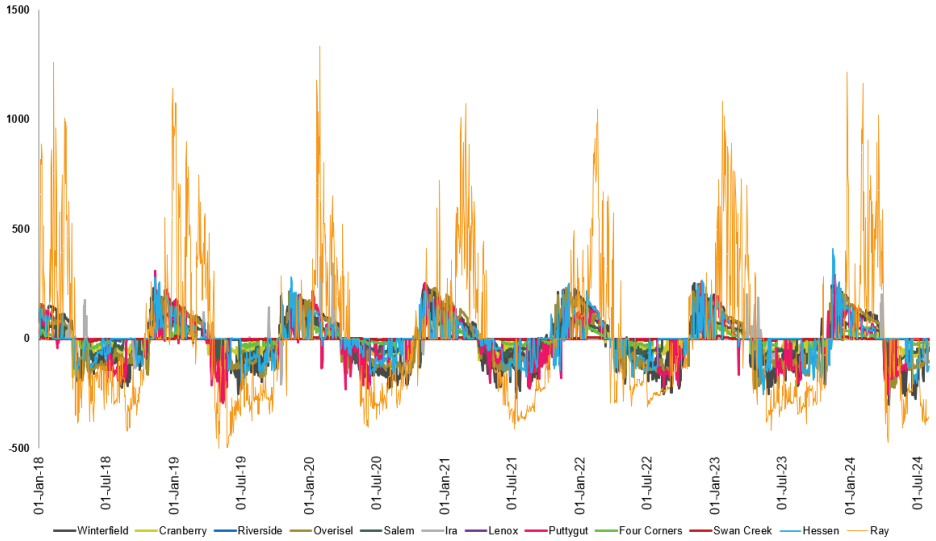
When temperatures rise, storage fields can be shut in for hours or days to adapt to customer load. This shut-in capacity can be used to provide system resilience in the event of unplanned outages on the system impacting supply.

The peaking fields serve multiple purposes:

- **Use during peak/design or near peak/design days.** Peaking fields may be needed when significant quantities of gas are required to meet customer demand. Because of its unique properties, the Ray field can be used as a peaker field when its inventory and gas conditioning equipment allow for it.
- These fields, depending on inventory, **can be used to reduce interstate pipeline supply** at the end of the winter season should excess capacity remain. They also **can provide supply capacity reserve** off peak/design for resiliency.
- The peaker fields **diversify storage supply and reduce reliance on Ray to meet peaking needs.** Additionally, they avoid relatively high fixed costs associated with interstate firm capacity and third-party storage. To aid in the reduction of our reliance on Ray, the Northville Gas Conditioning project is underway to help the fields provide quality gas when called upon.

Figure 7 shows that Ray uniquely fills the role of a peaker field (because it can deliver high rates of gas flow) and a baseload field because of its ability to hold a large volume of gas.

Figure 7: Daily Storage Field Injections (negative) and Withdrawals (positive) by Field from January 2018 - July 2024 (mmcf)



3. STORAGE WELL INTEGRITY PROGRAM

The key risk in storage field operations is degradation of the well, allowing gas stored in the reservoir below to escape and leak into the surrounding area.

Storage asset maintenance involves inspections (i.e., “logging”), repair, rehabilitation, and decommissioning for wells that provide less value to the customer. In addition, new wells with

horizontal drilling technology can be added to the system to enhance access to the storage field to replace decommissioned wells.

Well Inspections

Consumers Energy inspects wells to determine their current state and to assess risk. The *Storage Asset Plan* complies with Federal Pipeline Safety regulatory requirements, and the applicable sections of API RP 1171.

These procedures govern operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping requirements for all existing underground natural gas storage facilities.

Integrity assessments of underground storage wells began in 2017 to support the 10-year compliance timeframe for completing all risk management activities by 2026. Based on these new requirements, all wells will have three current logs at the completion of the 10-year rehabilitation program.

Well Rehabilitation

The Company's 10-year Well Rehabilitation Program began in 2017, and is on track to have all wells remediated by 2026, following publication of the PHMSA interim final rule to address underground storage safety issues.

This Program involves remediating wells across Consumers Energy's storage portfolio to return them to 'like-new' condition as well as to comply with the baseline assessment period of the final rule from PHMSA. Primary benefits of the well rehabilitation include:

- Safer and more efficient long-term storage operation by reducing risks stemming from factors such as corrosion, gas migration, leaks, and well integrity issues.
- Improved well deliverability.

Well Reassessment/Preventative and Mitigative Measures Program

A well-specific Preventative & Mitigative (P&M) Measures Program is in development for each well that completes the Well Rehabilitation Program.

The current plan provides a 21-year outlook for well work that will continue to verify and monitor well integrity. This P&M Program began in 2024, as outlined by the seven-year assessment cycle prescribed by Federal underground storage requirements.

Items included in the P&M Program include specific activities depending on well type: facility, observation, and Class II disposal wells. Maintenance includes items such as logging frequency, fill depth checks, slickline cleanout of paraffin for wells with known paraffin issues, mechanical integrity testing (MIT) on wells with tubing and packer systems, and fluid checks on wells with known water levels.

New Well Drilling

The purpose of the New Well Drilling Program is to identify the best locations to drill new wells within the storage assets. Important considerations include: the sequencing of well logging, remediation, new drilling, and plugging to ensure continued deliverability.

Consumers Energy is taking a holistic system view that these activities follow a logical sequence. For example, new well drilling should precede well plugging and decommissioning if practical, to ensure short-term flow is not significantly compromised. Options to accelerate drilling should be considered, when possible, to ensure remediation, new well drilling, and plugging follow an optimal schedule.

- Drilling new wells includes centralizing multiple wells to one location. This reduces overall operational maintenance and could reduce overall storage pipeline lengths.
- Using seismic mapping and reviewing of existing well information to place the well within the best part of the reservoir for increased deliverability while minimizing liquid production.
- Using safe drilling operations that provide a clean well for injection and withdrawal.
- New wells allow for drilling to current standards and potentially allow for plugging of aging wells that may present higher risk.

Well Re-Entry

A subset to the New Well Drilling Program has been initiated and focused on re-entering existing horizontal or deviated wells and drilling new drain holes. **Re-entry work is less expensive** than a full new well as the casing and pipeline are already installed.

Re-entering an existing well further **helps to improve field and well deliverability,** especially for wells that were drilled off structure or too deep on the structure. The additional rate can be used to either improve the field overall deliverability or allow for plugging of nearby vertical wells if they have integrity concerns but have sufficient flow rates to reduce risk without impacting storage field performance.

Additional benefits to the Program include using part of an existing well to plugback the original horizontal well and drilling additional drain holes to increase deliverability. This work uses wells with good integrity and coil tubing equipment that is a closed system.

Well Plugging

Well plugging is performed on certain wells, balancing risk with reliability and customer value.

- Plugging poor-performing, high-risk wells decreases maintenance expenses and reduces risk.
- After a well is plugged, the Company reduces its land footprint by restoring the area.
- Plugging a well reduces methane emissions by reducing maintenance related venting, and fugitive emissions associated with system piping and wellhead components.

Plugged Well Monitoring

In 2022, Consumers Energy contracted a third party to review all plugged wells within the Company's gas storage boundaries. The work included creating wellbore diagrams and classifying the plugging as *questionable*, *adequate*, or *exceptional*. This classification was used to develop monitoring plans for both the Company's plugged wells and third party plugged wells.

The plugged well monitoring plan for the Company's plugged wells will have a frequency based on the plugging classification. **The wells classified as *questionable* will be field monitored more frequently** than the wells classified as adequately plugged. The exceptionally plugged classified category will be field monitored the least frequency. The plugged well will be classified and a baseline field monitor will be completed within three years of plugging completion.

The plugged well monitoring plan for third party wells includes field monitoring for any potential gas leakage every five years for questionably plugged wells that don't have a bottom cement plug through the storage zone. These wells are drilled through the storage zone and are located within a quarter mile radius of a Consumers Energy well. Monitoring is limited to landowner or well owner cooperation.

This work will be recurring with a frequency based on the plugging classification and the evidence of gas leakage.

Storage Lateral Pipeline Replacement

The purpose of the Storage Lateral Pipeline Replacement Program is to replace and upgrade storage laterals based on age, condition, relative risk, and association with the other gas storage programs. Primary improvements anticipated from the program include:

- Installation of launcher and receiver barrels that allow for pipeline inspections.
- Potentially changing the pipeline length and size based on the new well drilling and well plugging programs.

These changes will help reduce risk while creating a more efficient path for gas flow to the larger natural gas system.

Northville Lyon 29/34 Liquid Removal Project

The primary focus of the Lyon 29/34 facility is to deliver transmission quality gas to the pipeline system and act as a metering station.

On peak days, this site is an important additional source of natural gas supply to the metro Detroit area. During 2018, 2019, and 2020 there were multiple occasions of gas purity issues occurring during the gas withdrawal season associated with water content.

The Lyon 29/34 facility upgrade project will help improve gas purity, measurement accuracy, and pipeline reliability by reducing corrosive components from the gas stream and improve site performance by installing gas purification equipment.

4. STORAGE FIELD ASSET PLAN

In alignment with the Storage Well Integrity Program and based on scenario modeling completed in 2018 through the lens of Consumers Energy's four objectives, the Company assessed the potential retirement of four low-cyclic fields to consolidate the storage system: Swan Creek, Four Corners, Lyon 34, and Riverside. Collectively, these fields provide less than 1.5% of the Company's gas supply throughout the winter.

Model results indicated three fields still provide value to customers and showed that Riverside may be a viable candidate for retirement.

- Removing Riverside from the storage portfolio has minimal cyclic impact, given the small amount of working gas volume at 1.48 Bcf, but has other operational considerations because it directly supplies three small city gate stations.
- Riverside contained approximately 9% of the system's total number of storage wells in 2018. Retirement would eliminate an estimated 14% of total risk associated with storage wells, including 5.8 metric tons of methane emissions.
- The remaining three fields represent just under 2% of the overall system risk and are currently providing significant supply resiliency. They also have a high deliverability to well count ratio that is used to supply peak demands.

Considering the items stated above, the Company decided to move forward with divestment of the entire Riverside storage field. The Riverside storage field supplies customers in adjacent communities via city gates directly to the field.

The Company's engineering team developed alternate supply options for the three city gates that span the distribution, transmission, and storage assets. The execution schedule for these projects occurs between 2023 and 2025. The completion of these projects will allow the Company to retire or sell the storage field.

The Company is currently pursuing the sale of the storage field with a tentative closure date in 2025. Divestment of the Riverside storage field will reduce system risk and O&M expenses associated with operation of these storage assets with minimal impact to overall system deliverability.

Figure 8: Storage Well Integrity Program Overview

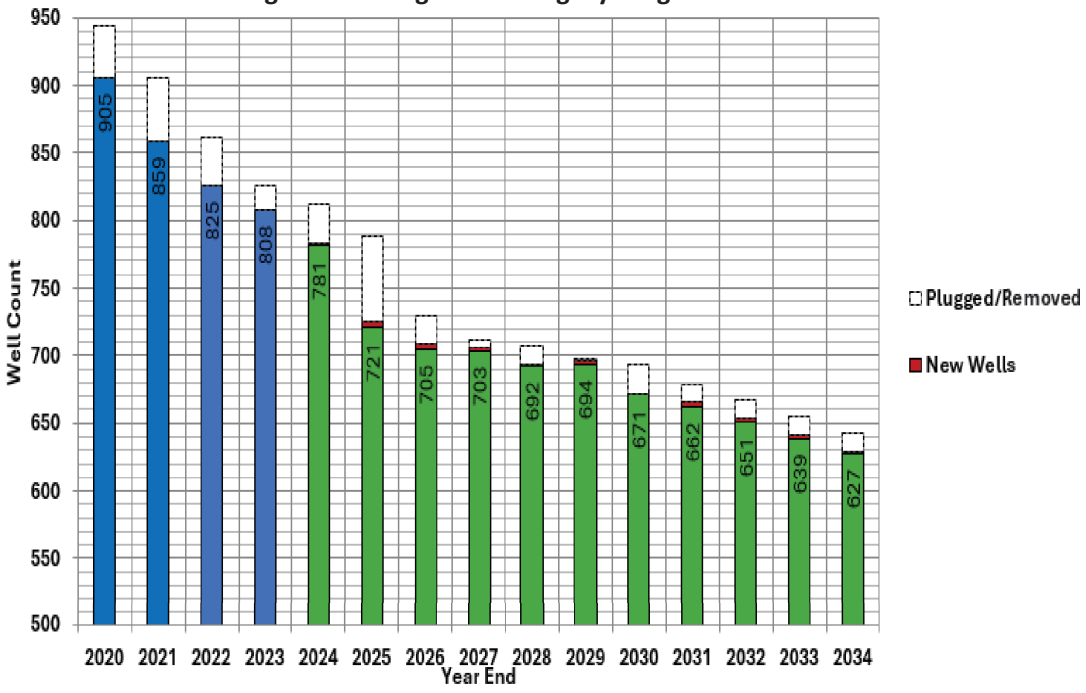


Figure 8 identifies that the combined approach of the Storage Well Integrity Program and the retirement of the Riverside storage field would reduce the overall number of wells, which will result in lower risk, lower operating costs, and lower methane emissions, while ensuring system resiliency, deliverability of gas flow per well, and potentially improving gas quality resulting in less risk to compressor station operations and downstream facilities.

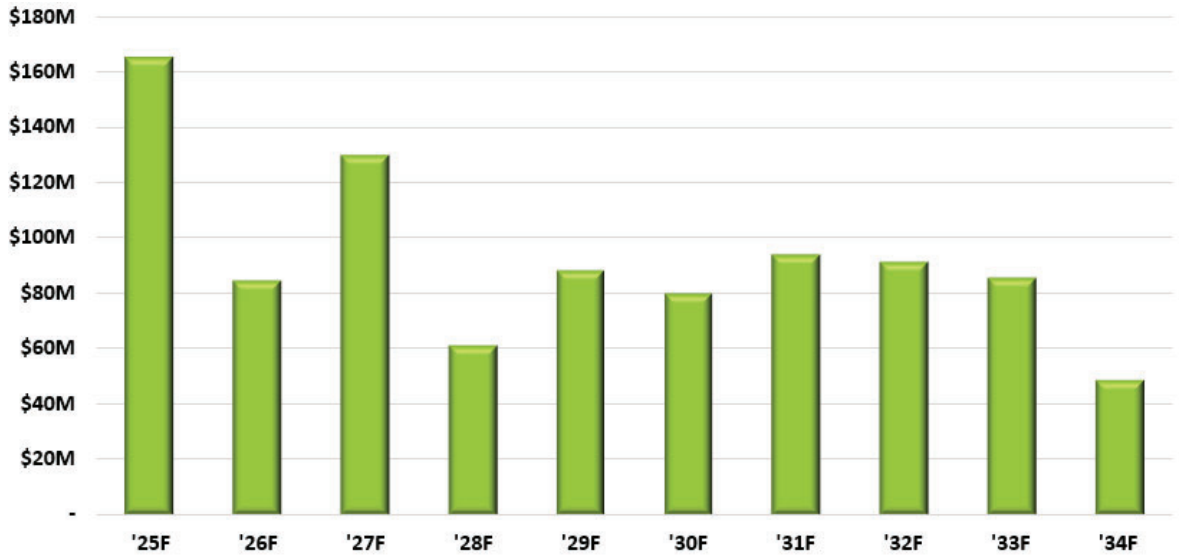
This reduction in the overall number of wells will have a minimal reduction in working gas capacity from an approximate current amount of 154 Bcf to a forecasted amount of 152 Bcf in 2027.

5. STORAGE ASSET FINANCIALS

Figure 9 shows the spending needed to efficiently and effectively execute the Storage Well Integrity Program and other investments in the storage asset area.

This investment plan aligns with Company objectives by reducing asset risk (safe), increasing the deliverability of each remaining well and positively affecting the natural gas system's resilience (reliable), reducing the overall well count (affordable), reducing the emissions points in this system (clean).

Figure 9: Storage Capital Investment Plan



B. Compression Asset Plan

Consumers Energy has eight compressor stations that pressurize and condition natural gas for safe transport through the pipeline and distribution systems, as well as injection into and withdrawal from underground storage.

The compression fleet can be segmented, based on the purpose of the compressor station, into storage, transmission, and distribution stations, as described below in Table 2.

Table 2: Overview of the Four Types of Compressor Stations

	Storage Compressor Stations	Transmission Compressor Stations	Transmission and Storage Compressor Stations	Distribution Compressor Station
Purpose	Inject gas into and withdraw gas from underground storage fields. Condition gas as needed to meet customer needs.	Receive and transport gas throughout the gas delivery system. Condition gas as needed to meet customer needs.	Compression units are storage units that also provide transmission compression.	Boost gas pressure through the distribution system when agricultural processes such as grain drying increase demand in the rural Thumb region of Michigan.
Station Names	• Ray • Muskegon River	• White Pigeon • Freedom	• Overisel • Northville	• Huron

	• St. Clair			

Consumers Energy operates the fleet with local Company personnel while monitoring through Gas Control with SCADA.

The Company monitors system pressures, flows, and key high-volume customers. The station control room is linked to the other utility back-up control rooms in real-time, per the control room standard for physical and cybersecurity assurance.

Table 3 provides a more detailed summary of the compression units at the storage and transmission stations.

Table 3: Summary of Compressor Units

Station	*Mothballed/Retired*				*Operable*			
	Units	# Units	Unit HP	Total HP	Units	# Units	Unit HP	Total HP
Ray					CAT 3616	5	4,735	23,675
Muskegon River	HVC	2	3,286	6,571	TLA	2	3,400	6,800
	Turbine	1	10,500	10,500	HBA	4	2,600	10,400
					Turbine(Suction boost)	1	10,076	10,076
St. Clair					Waukesha	4	4,835	19,340
					T-4500	2	3,971	7,942
Overisel					TLA	4	2,700	10,800
Northville					TLA (Transmission)	2	2,700	5,400
					TLA (Storage)	2	2,700	5,400
White Pigeon	KVT	2	2,000	4,000	W-330	2	3,600	7,200
	W-330	2	3,600	7,200	CAT 3616	3	4,735	14,205
					V-250	2	2,000	4,000
					CAT 3608	1	2,370	2,370
Freedom					Waukesha	5	3,750	18,750
Huron					CAT 3512	1	1,035	1,035
System Total		**7**		**28,271**		**40**		**147,393**

1. COMPRESSION ASSET CLASS 10-YEAR FOCUS

- Reduce system risk and methane emissions through retirement and decommissioning of vintage compression units and equipment.
- Improve fleet reliability and system resilience through increased system health monitoring, automation to maintain asset performance, and preventative maintenance.
- Improve system resilience and maintain gas compression facility deliverability through alternative flow path validation and creation, as well as implementation of robust design enhancements to existing

equipment to protect major natural gas supplies from interruption. Use system supply requirements, station assessments, and the Total System Resilience process to inform investments.

- Overall, the Company has a goal to achieve 30-40% utilization for the entire compressor fleet. Considerations for optimal utilization are described below in *Compression Asset Management*.

2. COMPRESSION ASSET MANAGEMENT

The Company's 2023 system weighted average compression utilization of 22% is below industry average of about 50%. The utilization rate calculates the amount of time that a compression unit is available to operate vs. the amount of time that it does operate.

Utilization is impacted by winter weather conditions and typically trends up when the winter is colder than normal, and a higher amount of storage is used. It will trend down when winter weather is warmer than normal, and a lower amount of storage supply is used. It also is affected by how and where gas is delivered by suppliers, the interstate pipeline delivery pressure verses Company transmission line pressure, conditions outside of the Company's natural gas system, asset availability, and other factors.

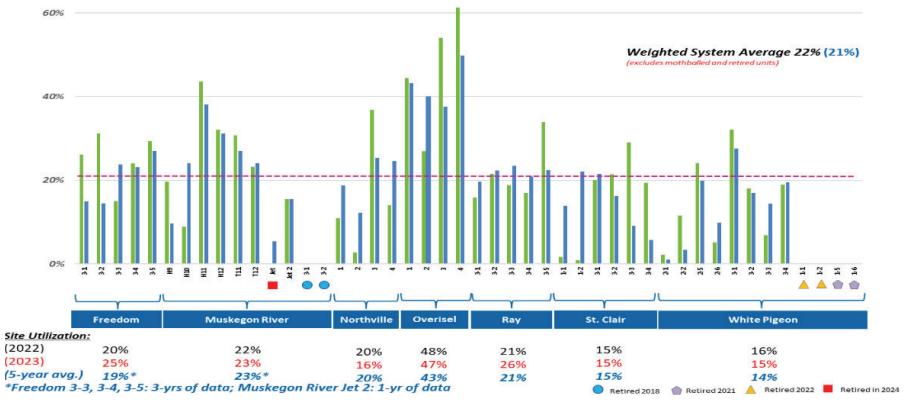
Overall, compression assets don't anticipate a utilization rate as high as the industry average due to the uniqueness of the Company's natural gas system.

- The Company's compression assets are used more to serve peak day and seasonal needs of storage assets, both for injection and withdrawal. Some compression assets are needed to ensure reliability at the station to avoid negative impacts to our customers as well as to provide the flexibility necessary to enable use of city gate supply.
- Another consideration, given the locational supply flexibility offered by the Company's natural gas system, is that interstate pipeline supply-focused compression may fall below industry average utilization depending on market pricing conditions.

The Company believes that an increase from the current 22% compression utilization is possible and can be achieved through efforts to improve the reliability of compressor stations and allowing the retirement of aging units. This will increase the utilization of the other compressor units and will be accomplished while considering the Company's natural gas system's resilience and supporting that system's maintenance needs.

Figure 10 illustrates the 2023 utilization of each compressor unit including mothballed units or units not currently in service.

Figure 10: 2023 5-yr Average Utilization by Compressor Unit



The Compression Demand Schedule as seen below, is a communication tool that describes how much horsepower is needed at each station to meet planned needs for anticipated operational conditions, including design conditions. Random outage rates analyze potential compression buffer or shortfalls in terms of units and hp at each station.

The Company is the supplier of last resort and must prepare for design conditions that are not regularly seen, and that contribute to lower than peer compression utilization.

Figure 11 shows the monthly compression demand schedule that indicates the required quantity of units, hp, and projected peak demand months for each station.

Figure 11: 2024 Monthly Compression Demand Schedule (Example)

2024 MONTHLY COMPRESSION DEMAND SCHEDULE (10-20-2023)

				WITHDRAWAL			INJECTION							WITHDRAWAL	
Compressor Stations	#Units	Unit HP	Total HP	Jan 2024	Feb 2024	March 2024	April 2024	May 2024	June 2024	July 2024	Aug 2024	Sept 2024	Oct 2024	Nov 2024	Dec 2024
WHITE PIGEON	**Min Req'd HP*** **			**18,670**	**18,670**	**18,670**	**18,670**	**18,670**	**18,670**	**18,670**	**18,670**	**18,670**	**18,670**	**18,670**	**18,670**
W-330 (2-5,2-6)	2	3,600	7,200	4	4	4	4	4	4	4	4	4	4	4	4
CAT 3616 (3-2,3-3,3-4)	3	4,735	14,205												
V-250 (2-1, 2-2)	2	2,000	4,000	1	1	1	1	1	1	1	1	1	1	1	1
CAT 3608 (3-1)	1	2,370	2,370												
Unavailable Units (Notes)															
FREEDOM	**Min Req'd HP**			**11,250**	**11,250**	**11,250**	**11,250**	**11,250**	**11,250**	**11,250**	**11,250**	**11,250**	**11,250**	**11,250**	**11,250**
Waukesha (3-1,3-2,3-3,3-4,3-5)	5	3,750	18,750	3	3	3	3	3	3	3	3	3	3	3	3
Unavailable Units (Notes)															
OVERISEL	**Min Req'd HP**			**8,100**	**8,100**	**8,100**	**5,400**	**5,400**	**8,100**	**8,100**	**8,100**	**8,100**	**8,100**	**8,100**	**8,100**
TLA (1,2,3,4)	4	2,700	10,800	3	3	3	2	2	3	3	3	3	3	3	3
Unavailable Units (Notes)	Fuel gas & Unitized cooling project			Fuel gas	Fuel gas		Unitized Cooling	Unitized Cooling	Fuel gas	Fuel gas	Fuel gas	Fuel gas	Fuel gas	Fuel gas	
RAY	**Min Req'd HP**			-	**23,675**	**23,675**	**14,205**	**14,205**	**18,940**	**18,940**	**23,675**	**23,675**	**23,675**	**18,940**	-
CAT 3616 (3-1,3-2,3-3,3-4,3-5)	5	4,735	23,675	0	5	5	3	3	4	4	5	5	5	4	0
Unavailable Units (Notes)														*See Notes	
ST. CLAIR	**Min Req'd HP*** **			**19,040**	**19,040**	**22,222**	**12,702**	**12,702**	**14,280**	**14,280**	**14,280**	**14,280**	**14,280**	**12,702**	**12,702**
Waukesha (3-1,3-2,3-3,3-4)	4	4,760	19,040	4 Recip	4 Recip	**5 Units	3 Units	3 Units	3	3	3	3	3	3 Units	3 Units
Turbine (1-1,1-2)	2	3,971	7,942						Turbines used only while Field Pressures allow for injection						
Unavailable Units (Notes)				Plt 1 comp work	Plt 1 comp work										
MUSKEGON RIVER	**Min Req'd HP*** **			**28,619**	**28,619**	**28,619**	**8,600**	**8,600**	**8,600**	**8,600**	**8,600**	**8,600**	**8,600**	**14,600**	**26,019**
TLA (T-11, T-12)	2	3,400	6,800	2	2	2	1	1	1	1	1	1	1	2	2
HBA (H-9,H-10,H-11,H-12)	4	2,600	10,400	4	4	4	2	2	2	2	2	2	2	3	3
Turbine (Suction Boost-existing)	1	10,500	10,500	1	1	1	0	0	0	0	0	0	0	0	1
Turbine (Suction Boost-new)	1	11,419	11,419												
Unavailable Units (Notes)															
NORTHVILLE	**Min Req'd HP**			**5,400**	**5,400**	**5,400**	**2,700**	**2,700**	**2,700**	**2,700**	**5,400**	**5,400**	**5,400**	**5,400**	**5,400**
Unit 1&2 (Transmission)	2	2,700	5,400	1	1	1	1	1	1	1	1	1	1	1	1
Unit 3&4 (Storage)	2	2,700	5,400	1	1	1	0	0	0	0	1	1	1	1	1
Unavailable Units (Notes)															
Total	40		157,901	91,079	114,754	117,936	73,527	73,527	82,540	82,540	89,975	89,975	89,975	89,662	82,141

Minimum required horsepower reflects what is required to pump Design rates, backup engines are required for planned and unplanned outages.
* Ray HP in November required up to the start of Ray field survey, 2 units available post survey
** St Clair turbines are availabe for March withdrawals if base field pressures allow or for use with peaker fields
*** If the indicated number of units cannot be met then other units (engines or turbines where applicable) must be substituted to try to meet HP Demand requirements even if there is no requirement for the units

The demand schedule highlights the variation in monthly peak demands for storage and transmission compressor stations. In general, storage compressor stations tend to have greater variability in hp requirements month-to-month as they are used to adapt to varying customer demand while meeting summer injection and winter withdrawal needs.

- The lower hp utilization at St. Clair and Ray reflects how the Company uses the capability of those facilities to adapt to operational conditions. This reflects their ability to be adjusted as needed to meet continuously varying customer demand and system conditions.
- High utilization of most of the hp typically occurs when those facilities are using storage inventory and that compression is needed for withdrawal, which occurs later in the winter, generally during February and March.

Late season focus remains on cycling the base storage fields to reduce risk of gas migration in the fields, and this results in some stations' utilization being comparatively low. Using compression to cycle fields allows the Company to hold inventory in more prolific storage, and thus reduces the need to procure large quantities of more expensive pipeline transportation and supply during the winter, which is not guaranteed to be available.

Peak day demands, including those that may be associated with gas-fired generation, are expected to primarily be met with peaking storage at Northville, St. Clair, and Ray, given their high deliverability characteristics and their ability to be used to respond throughout the day needed by the varying electric generation load.

- To manage reliance on Ray, and to support the system resilience, hp is needed to refill Northville and St. Clair after a peak demand period in the winter to facilitate more frequent cycling of peaker fields.
- The lower utilization at White Pigeon reflects market conditions and locational pricing that is currently more favorable for supply to be received through Freedom and Northville.

Maintaining access to supply and flexibility for changes in the location in supply helps keep consumer market prices lower and the natural gas system more resilient.

Transmission compressor stations have more stable daily and monthly peak demands to meet ongoing gas demand and transport needs throughout the year. However, there are changing conditions at those stations throughout the year that affect utilization, like available interstate pipeline pressures, varying market conditions and planned/unplanned upstream facility outages.

3. COMPRESSION ASSET PLAN

Based on the scenario modeling, five long-term recommendations for compression reflect new operating realities and align with the Company's objective of improving the system's reliability, resiliency and optimal utilization. The recommendations are:

a. Accelerate the implementation of preventative maintenance program and practices, and gradually implement predictive technologies.

b. Decommission retired/mothballed compressor units.

c. Optimize the fleet of compressor units at Muskegon River to meet volume and pressure requirements.

d. Evaluate contingency options for resiliency and opportunities that mitigate risk of outages at the compression stations.

e. Assess feasibility of retiring additional compression assets to focus investment on most critical units and optimize portfolio.

f. Compressor Station Compliance with Proposed Michigan NOx RACT Rule.

The following sections describe each recommendation in more detail.

Implement Enhanced Maintenance Program and Practices, and More Predictive Technologies

Consumers Energy will enhance maintenance practices to ensure the implementation of more proactive and efficient prevention programs. This will eliminate expensive, reactive events, improve the compression fleet's ROR, reduce downtime and overall maintenance costs.

The Company's current compression maintenance practices don't allow for analytics-based decision making or preventative and predictive maintenance. This is primarily due to the following:

- Compression is operating on a break-fix cycle.
- Maintenance data (such as failure records and work order maintenance logs) is incomplete.
- Equipment condition data, such as temperature and in-flow pressure, is limited.

The Company also will improve record-keeping practices to ensure a standardized entry methodology or nomenclature for SAP entries.

Station performance and maintenance schedules and data are stored separately at each station in local templates. Investing in digital infrastructure will enable these important factors to be standardized across the fleet, and for performance monitoring and improvement to occur more efficiently.

Decommission Retired Compressor Units/Auxiliary Assets

Currently, there are 7 retired compressor units not being operated. These units are disconnected and removed from the system.

The Company's goal is to decommission these units, which enhance the site aesthetics and safety for employees, as well as reduce operating expenses.

The retired units, are located at Muskegon River, and White Pigeon:

- Muskegon River –Two HVC units (3-1 & 3-2) and one turbine
- White Pigeon – Two KVT units (1-1, 1-2) and two W-330's (1-5, 1-6)

Four KVG units (306, 316, 319, 320) at Muskegon River were decommissioned during 2020, and three HVC units (2-2, 2-3, 2-4) at St. Clair were decommissioned in 2021-2022.

The units in Plant 1 and Plant 2 at Freedom were decommissioned in 2023 after the completion of the Plant 3 Upgrade project.

The 5 units in Plants 1 and 2 at Ray were decommissioned in 2024.

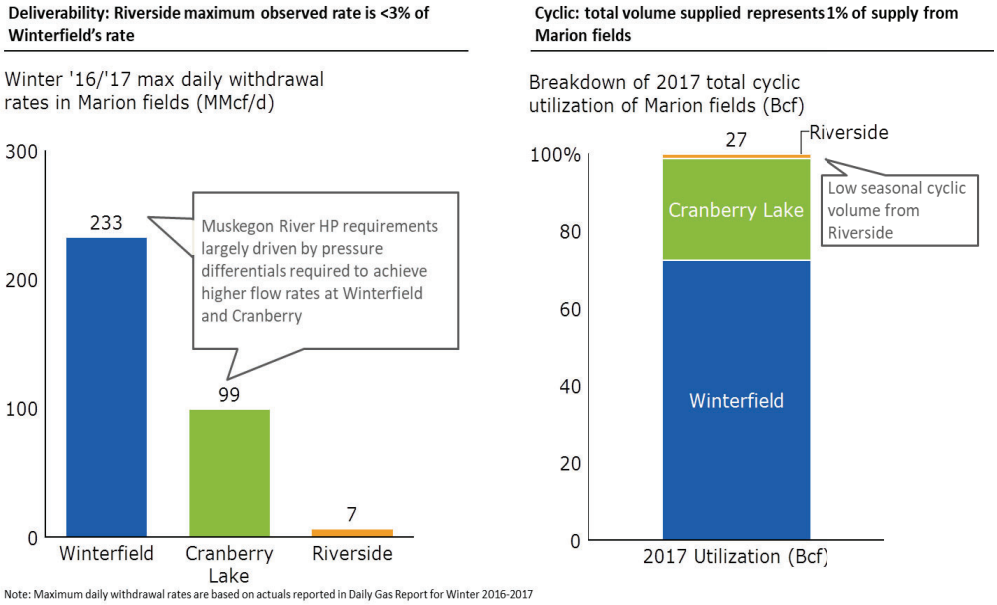
Engineering and planning activities are underway to support decommissioning activities at Muskegon River, and White Pigeon.

Optimize Compressor Units at Muskegon River to Meet Volume and Pressure Requirements

With the retirement of the Riverside storage field, another high-level evaluation was completed that validated that Muskegon River compressor station without the Riverside storage field still delivers value to the system:

- The Muskegon River storage compressor station will still be used to pressurize gas to inject into and withdraw from the Winterfield and Cranberry Lake storage fields.
- Muskegon River hp requirements are largely driven by pressure differentials required to achieve higher flow rates at Winterfield and Cranberry Lake, and the total cyclic volume supplied from Riverside is 1% of the supply from the storage fields in the region (Riverside, Winterfield, Cranberry Lake), as shown in Figure 12. Replacing the antiquated suction boosting compression with a new turbine will enable more reliable suction boosting and higher cycling from the remaining two storage fields. Therefore, the impact at the Muskegon River compressor station from retiring Riverside is minimal.

Figure 12: Maximum Daily Flow & Cyclic Capacities for Storage Fields Supported by Muskegon River



Consumers Energy is optimizing the compression horsepower at Muskegon River to meet volume and pressure requirements by:

- Completing the retirement of Plant 3 HVC pressure boosting units due to their age and ROR performance (2018). Completing installation of an in-kind replacement for suction boosting turbine. (Commissioned during winter 2022-2023).
- Retiring the existing turbine after the installation of the new turbine is complete (2024).
- Rebuilding to like-new the existing HBA and TLA (slower speed models) to extend their useful operating life by 2033.

Evaluate Contingency Options for Resiliency and Opportunities that Mitigate Risk of Outages at Compression Stations

The Company is analyzing resiliency in Compression, Storage, and Transmission, including gas flow path analysis and review of design improvements and hazard assessments.

A logical review of interrelated systems will occur in a manner that can identify specific potential failure points and quantifiable impacts. The components reviewed are typical of the following:

- Compression: compressors and engines including coolers, unit control and unit specific auxiliaries
- Gas conditioning equipment
- De-hydration equipment
- Natural gas heaters
- Slug catchers
- Filter-separators

- Scrubbers
- Mechanical-structural
- Main gas headers
- Isolation and control valves, regulators, and fire gate systems including valves
- Fuel / pilot gas systems
- Compressed air systems
- Electrical instrument & controls, transformers, switchgear, MCCs, panels
- Station Control and Network Systems and instruments

In addition, the Company will evaluate the overall gas compression system to identify recommended investments to support an overall increase to system resiliency:

- Areas that will be evaluated include, but are not limited to, a bypass out of the Ray Storage facility directly into the transmission pipeline system, mitigation of single point failures in the system, and fleet-wide system improvements.
- Results from site hazard assessments and focused self-assessments have been used to evaluate each station to make recommendations to standardize system design to mitigate overall risk to the system.

Annually Assess Feasibility of Retiring Additional Compressor Units

The Company annually assesses feasibility of retiring additional compression assets to prioritize investment on the most critical assets for an optimized portfolio. This includes the following:

- Monitor signposts such as reliability, performance, and load changes over time.
- Evaluate station/asset reliability and required units.
- Incorporate system resilience assessments.
- Assess station layout risk and developing mitigations.
- Develop business cases for retirements/additions.

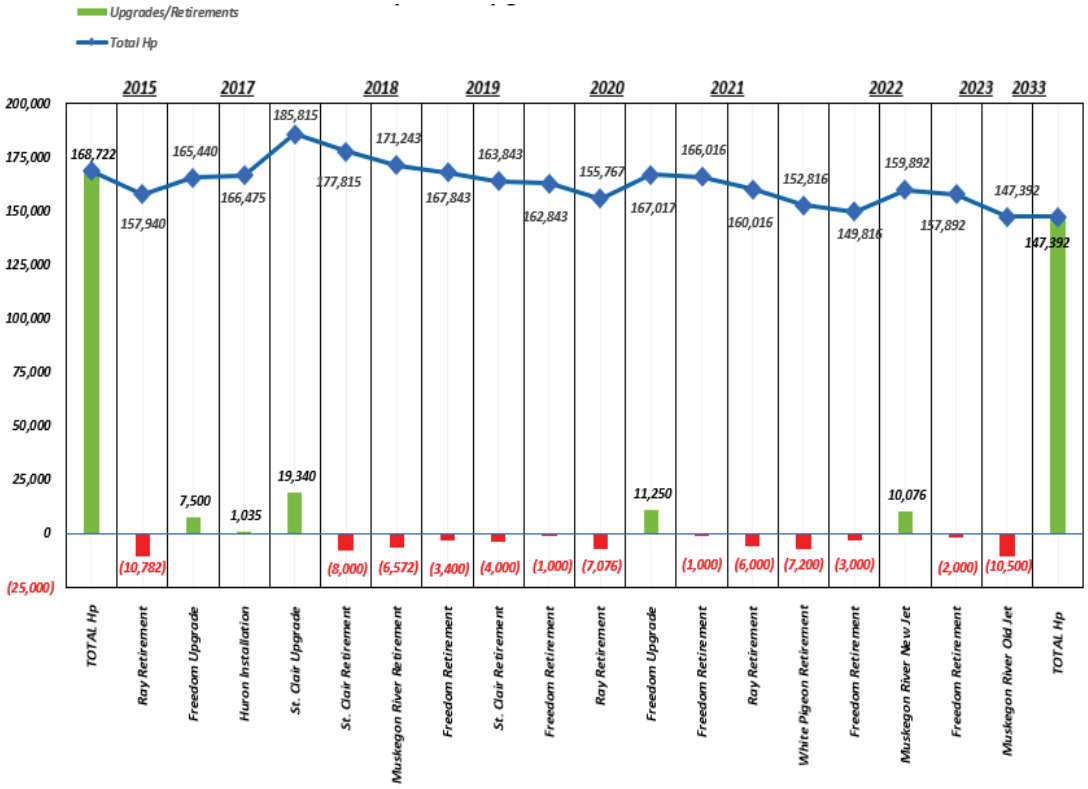
A transformation of compression maintenance practices to be more predictive and proactive, for example, will reduce ROR and increase reliability and performance of compression assets.

As these practices demonstrate further increases to reliability, the Company will evaluate the compression portfolio to identify the appropriate number of reserved capacity assets and amount of capability required at each station to meet peak demand. This aligns with the Plan's aim to improve supply resiliency and system optimization, including increasing the weighted average compression utilization rate as one of the 10-year outcomes.

Furthermore, the Company will monitor other factors that may impact the evaluation of whether to retire or upgrade compressors over time. For example, increasing market supply, storage cycling, or storage deliverability via compressor stations such as Overisel and Northville may require increasing hp at these two stations to reliably handle increase in peak or seasonal demand.

Figure 13 shows the Company's plan to optimize the compression fleet with an approximate net reduction of 21,328 hp from 2015 to 2033 without impacting customer deliverability.

Figure 13: Compression Fleet Optimization (2015-2033)



Compressor Station Compliance with Michigan NOx RACT

These rules impact the older, slow speed units at Overisel, which has 4 engines that require modification to achieve proposed NOx emission limits.

Overisel is in an area that is currently designated as ozone non-attainment and is subject to the Michigan NOx RACT rule, a project is underway to modify the engines to meet the new NOx emission limits.

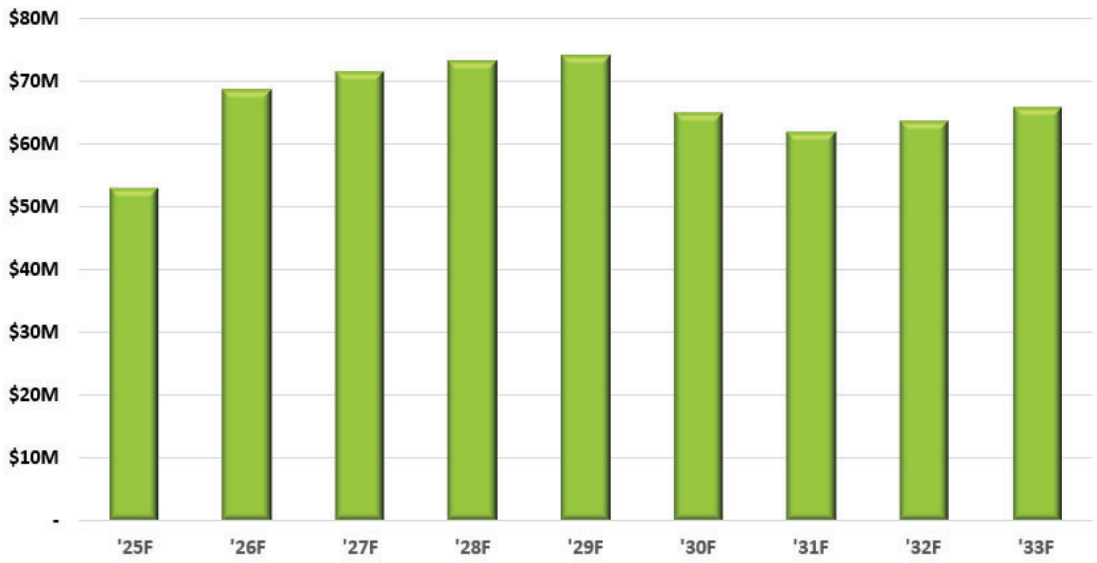
4. COMPRESSION ASSET FINANCIALS

Based on the modeling and planning to date, the forecasted capital investment plan for the Company's compression assets is shown in Figure 14.

This capital investment plan will be updated routinely as assessments are completed, and business cases are created to support necessary spend plans.

Overall, this investment plan for compression assets aligns with the Company's objectives by reducing asset risk (safe), reducing the ROR and increasing utilization rates (reliable), optimizing the fleet with more modern equipment and modifying maintenance practices (affordable), and reducing the amount of equipment emissions (clean).

Figure 14: Compression Capital Investment Plan



C. Transmission Assets

The Company's transmission system is the 'expressway' of the gas system, transmitting large quantities of gas in pipe diameters ranging from 4 inches to 36 inches, at high pressures between 400 and 1,185 pounds per square inch ("psi").

Gas Transmission lines move gas from interconnects, to and from storage, as well as to city gates for delivery to the distribution system. Within the Transmission system is Transmission Operated as Distribution ("TOD") pipe. TOD is considered transmission pipeline for DOT Reporting, but from an operating perspective is part of the distribution system.

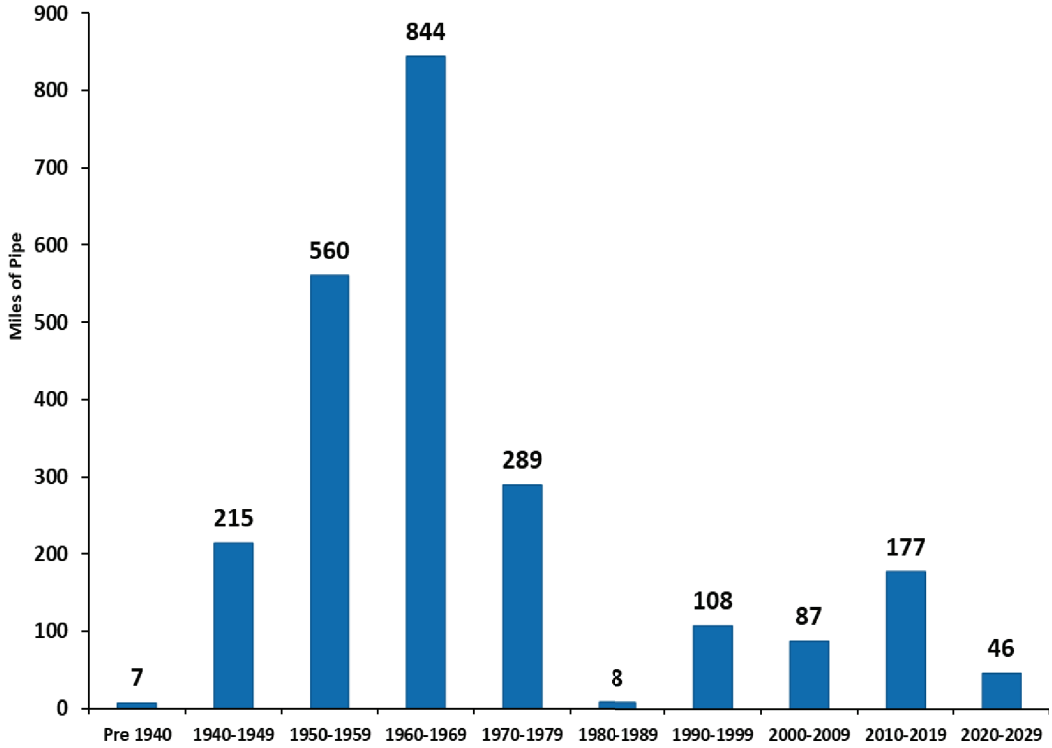
Per the Company's 2023 Transmission DOT Report filing, there are 2,342 miles of pipeline. The associated breakdown of transmission pipeline mileage is shown in Appendix B.

The Company's goal is to meet the capacity needs of Michigan as well as to optimize the transmission system in terms of age, materials, and technology to ensure public safety.

The Plan to achieve this goal includes compliance with State and Federal Pipeline Safety regulatory requirements for inspections to address threats on the system and actions to mitigate risk. The Plan also continues investment in upgrading and replacing the Company's major pipelines and modernizing the system with remote-control valves ("RCVs") to quickly isolate the system when system integrity is compromised.

The weighted average age by miles for the transmission pipeline system is 52 years old. Approximately 1,915 miles, or 82%, of transmission pipe was installed in the 1970s or earlier, as shown in Figure 15.

Figure 15: Transmission Pipeline by Decade of Installation



1. TRANSMISSION ASSET CLASS 10-YEAR FOCUS

- Obtain the necessary technology for system response and needed flexibility with capacity throughput and diversity of flow paths for total system resiliency to reduce system risk and methane reductions caused by aging infrastructure. This is achieved through SCADA upgrades described below under *Technology*.
- Increase the pipeline integrity scope to account for the additional remediation work for transmission piping to meet new regulatory requirements for Maximum Allowable Operating Pressure ("MAOP") reconfirmation, as well as the incremental remediation as an outcome of inspecting TOD and storage lines.
- Attain 70% of RCVs installed on valves on the transmission system by 2028.
- Upgrade the Company's natural gas supervisory & control data systems, which allow for secure monitoring and control of the natural gas system, and upgrade city gates.
- Reduce the probability of high impact natural gas system failures.
- Eliminate MAOP exceedances by installing emergency shut down devices at facilities, install filtration equipment at facilities, and perform maintenance pig runs.

2. TRANSMISSION ASSET PLAN

a. Capital Remediation for Transmission Pipeline (i.e., "mainlines")

By the end of 2025, all transmission mainline miles will be inspected regardless of consequence area classification. This does not include transmission miles within the storage fields, compressor stations, TOD segments or transmission lines installed within the last 10 years.

Within the transmission mainline miles are high-consequence areas ("HCA") and moderate consequence areas ("MCA"). HCA and MCA classifications are inspected on a recurring basis, six and nine years, respectively.

In addition to the planned, on-cycle inspections, risk mitigation inspections for transmission lines display early signs of deteriorating conditions, such as Stress Corrosion Cracking ("SCC").

- SCC is a form of environmental cracking that requires three conditions to develop, susceptible material (steel), stresses on the pipeline that are higher than the threshold for SCC and an environment that supports cracking such as local soils and groundwater.
- Many factors can affect the initiation and propagation of SCC, but a pipeline's coating system provides the primary barrier with Cathodic protection providing a secondary barrier.
- The environmental factors that support SCC can develop under the right conditions when the coating on a pipe is compromised or dis-bonded.
- In 2015, one of the Company's pipelines ruptured due to SCC. Since that time, the Company has assessed pipelines that have the highest potential for SCC to occur, and there have been instances where SCC was found and remediated.

The Company completed the construction of the Mid-Michigan Pipeline project in 2024 to replace an existing 70-year-old pipeline that has shown signs of SCC and experienced the rupture in 2015.

This project is further discussed in below in the section concerning the *Transmission Enhancements for Deliverability and Integrity* ("TED")-I program.

b. Inspection for Transmission Operated by Distribution (TOD) Pipelines

Within the total Company TOD miles, 100 miles of TOD reside within HCAs and will follow the inspection cadence discussed above.

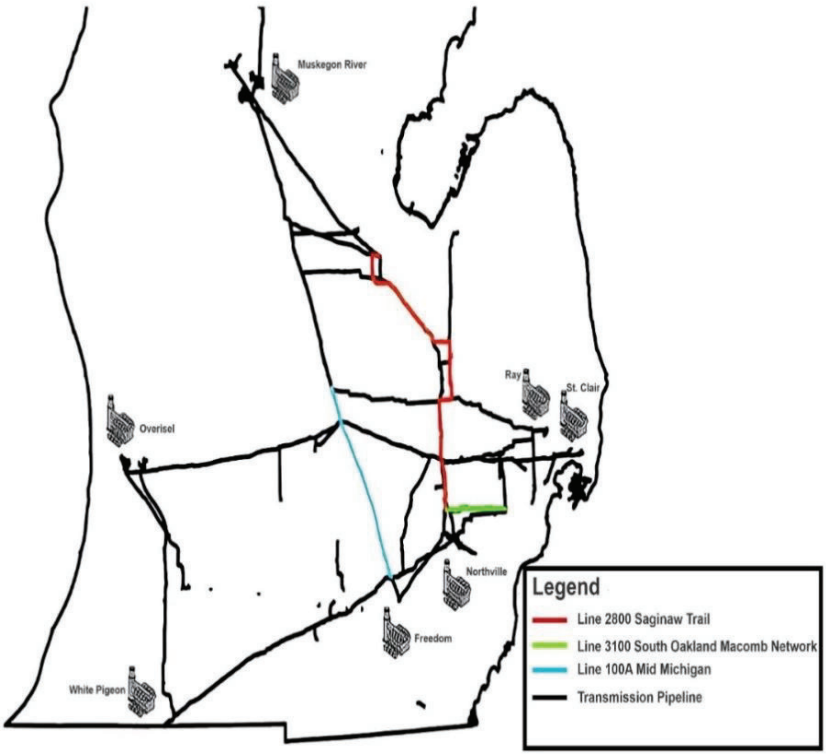
For the remaining non-HCA TOD pipelines, the Company is extending the Low Stress Assessment process to inspect and remediate areas with low cathodic protection levels to ensure continued safe operation.

c. Transmission Enhancements for Deliverability and Integrity projects

Transmission Enhancements for Deliverability and Integrity ("TED-I") pipeline projects focused on maintaining integrity, deliverability, and include transmission pipeline replacements of higher relative risk pipe to ensure safe operation. Higher relative risk pipe includes segments with previous anomalies or stress characteristics related to integrity management risk mitigation. Consumers Energy identified certain transmission pipelines to replace or upgrade due to their condition.

The major TED-I projects are Saginaw Trail Pipeline (started in 2017 and completed in 2020), the South Oakland Macomb Network (started in 2018 with construction and completed in 2021), and Mid-Michigan Pipeline (construction 2023 and 2024). As of 2024, all major pipeline replacements are successfully complete. No additional major pipeline replacements are planned. The completed projects are shown below in Figure 16.

Figure 16: Map of TED-I Gas Transmission Pipeline Projects



As transmission lines age, there are two primary factors considered for replacement, *capacity needs* and *integrity*.

All transmission lines are continuously evaluated based on these two factors, which form the basis for prudent decision making in repair versus replacement. Capacity requirements are factored into line replacements to ensure customer deliverability.

- TED-I pipeline projects improve customer reliability and advance public safety by replacing or retiring higher relative risk pipe segments and, in some cases, increasing capacity which in many cases enhances system resilience.
- Replaced pipelines also have enhanced pipeline pressure control and isolation capabilities.
- The Company is planning the Oakland Resilience Interconnect, a transmission interconnect with DTE Gas, in 2025 that will improve overall system resiliency to the benefit of customers of both Companies. In accordance with 1929 Public Act 9, the Companies received a certificate of necessity to construct and operate the interconnect on October 10, 2024. This project is responsive to the Commission's recommendation pertaining to risk mitigation in the 2019 SEA.

d. City Gates

A city gate is a distribution center and/or fuel station. The Company operates 90 city gates as of December 31, 2023, where pressure is regulated and natural gas is odorized for safe delivery to homes and businesses. Over-pressure protection and SCADA monitoring equipment are located at city gates.

City gates are an important component to the natural gas system in that they reduce transmission line pressure for distribution use and in some cases improve the quality of gas before entering the distribution systems. Most city gates inject an odorant into the gas stream for leak detection through the sense of smell.

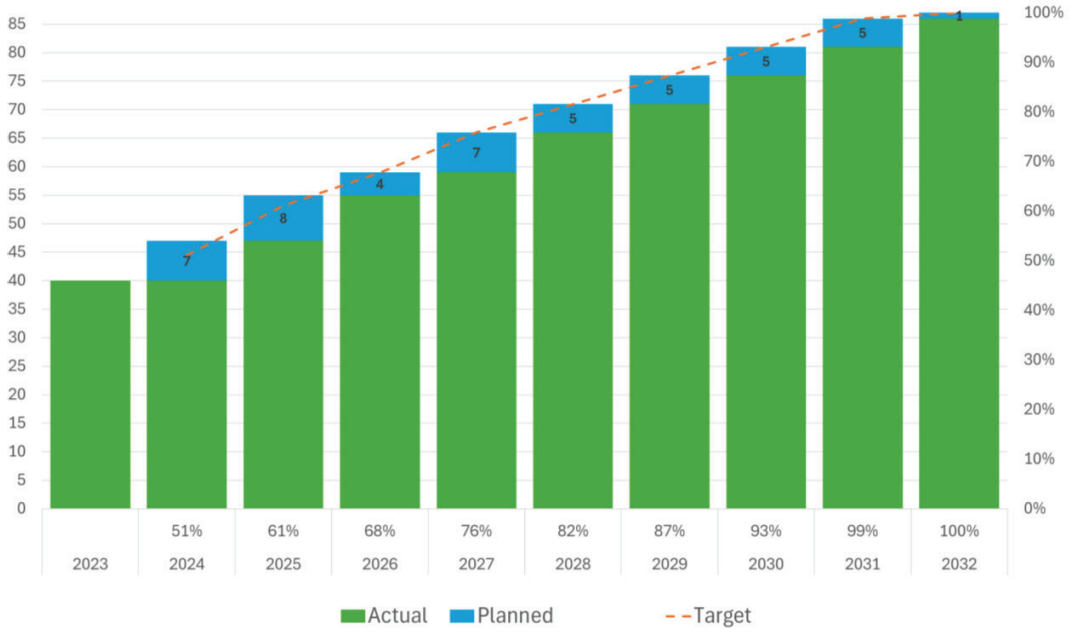
City gate facilities and their equipment have a reasonable life span of about 50 years. However, age alone is not the primary factor for rebuilding a city gate.

The city gate fleet goal is to 'modernize' 90% of the Company's city gates within this 10-year plan. *Modernization* is defined as upgrading the following mechanisms: emergency shutoff system, bath heater system, separation systems, and the required SCADA transducers for each stage.

The 10-year plan shown on Figure 17 calls for the modernization of 5-10 city gates each year. In addition to full rebuilds, components required for modernization will be rebuilt or added as appropriate rather than full rebuilds as specific station needs dictate in consideration of customer affordability. To achieve this target, annual spending between $1 to $13 million per city gate, or $40 to $60 million annually for the entire program for the next 10 years is required.

After modernization is complete, city gates will be rebuilt on a cycle that will ensure the entire fleet is rebuilt within 50 years, or as required for safety, customer demand, and high-performance demand.

Figure 17: City Gate Attribute Modernization Plan



e. Remote Control Valves (RCV)

RCVs are important safety components in the natural gas system. RCVs reduce response time in the event of damage to a transmission line or a rupture event. The ability to remotely and quickly stop the flow of gas is essential, and RCVs are the standard for achieving this across the system.

It is important to note that RCVs do not prevent failures from occurring but are intended to minimize the time gas flows after a failure. These RCVs also allow for manual operations if a condition calls for an operator to override the RCV. RCVs were first installed in 2017 in HCAs and at flexible points in the system.

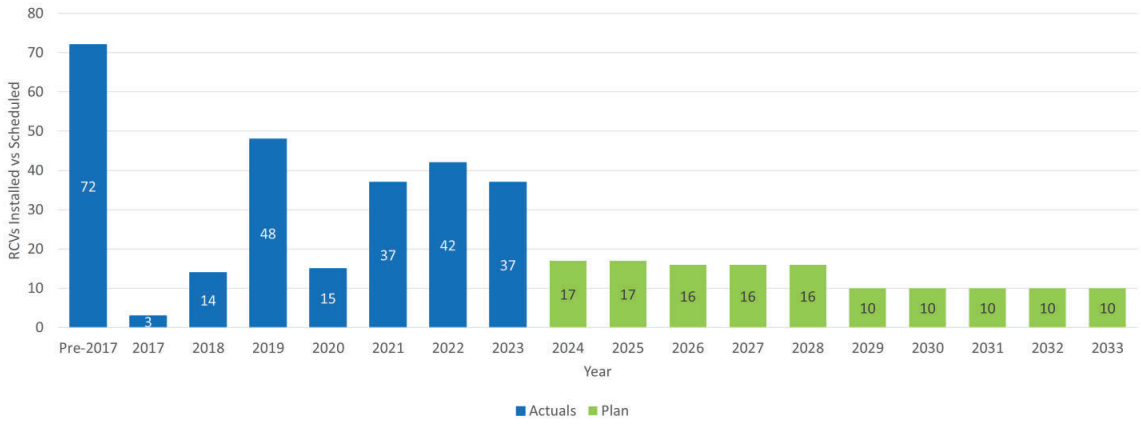
- Check valves will also be used on transmission tap lines when appropriate to aid RCVs in the isolation of a particular transmission segment.
- Check valve technology prevents the back feeding of gas in the event of an emergency.

To leverage RCVs as a means of increasing the safety of the transmission system, the Company is planning an installation rate toward a goal of 70% of the system valves by 2028, as shown in Figure 29. Figure 18 below represents the year in which the RCVs have been installed and are planning to be installed with final commissioning of RCVs sometimes occurring in the subsequent year.

This safety benefit is the time reduction to isolate the system during an emergency or abnormal operating condition. The current goal aligns with the continuously evolving prioritization of work, available resources, and system outage schedules.

In addition, a Gas SCADA system upgrade is being conducted to support this plan. Currently, the Company has 481 valves on the transmission system, requiring approximately 336 additional RCVs to reach the 70% goal.

Figure 18: Current RCV Installation Rate



Total # of RCVs	72	75	89	137	152	189	231	268	285	302	318	334	350	360	370	380	390	400
Percent Completed	14.9%	15.6%	18.5%	28.5%	31.6%	39.2%	48%	55.8%	59.2%	62.8%	66%	69.4%	72.8%	74.8%	77%	79%	81.1%	83.2%

f. Other Transmission Investments

In addition to the Transmission Investments mentioned above the Company invests in other programs that ensure safety, resiliency, reliability, and compliance with regulations. These include:

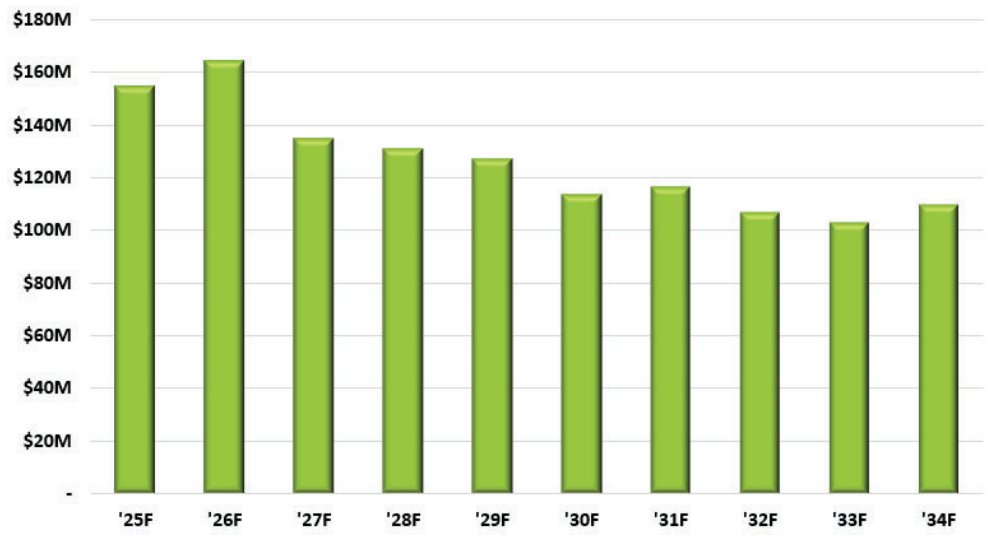
- **Asset Relocation**: Transmission investments include gas transmission infrastructure replacement projects that are required due to civic improvement activities initiated by federal, state, or local governmental units where transmission pipeline location or depth of cover requires relocation of an existing pipeline to prevent third-party damage, eliminate physical conflicts with other utilities, and to ensure continued safe operation. Major projects planned include Chippewa River line lowering, Rabbit River line lowering, and Townline Road line lowering.
- **Cathodic Protection Program:** This Program maintains compliance with federal regulations for cathodic protection of facilities.
- **MAOP Compliance:** Pipeline investments involve MAOP verification and remediation of transmission pipelines, including Transmission Operated by Distribution pipelines.
- **Deliverability Base Field Measurement:** These investments ensure accurate gas quality and measurement.
- **Deliverability Base Pipeline:** These investments support maintaining operations in accordance with State (Michigan Gas Safety Standard) and Federal Pipeline Safety regulatory requirements. The Company intends to eliminate transmission and storage identified inoperable valves by replacement and/or retirement. Types of projects include:
  - Replacement of valves, and if necessary, the associated valve operators, when inspection determines that the valves no longer perform as needed. Which may mean valves no longer turn or they may not fully seal off the flow of gas.
  - Replacement of piping due to MAOP revisions.
  - Construction of new sectionalizing valves and tap valves to improve system deliverability and help meet valve spacing requirements defined by State and Federal Pipeline Safety regulatory requirements; (iv) reconfiguration of tap piping (i.e., laterals) and associated valving upstream of city gate facilities as companion projects to city gate rebuilds.
  - Installation or retirement of pipeline taps to Transfer Meter Site facilities being attached to the Company's system.

3. TRANSMISSION ASSET PLAN AND FINANCIALS

Consumers Energy's transmission inspections, remediation work, city gate modernizations, and RCV installations provide the basis for the capital investment plan shown in Figure 19.

Overall, this investment plan for the transmission asset class aligns with the objectives by reducing asset risk (safe), ensuring the pipelines can flow when required (reliable), providing the necessary resilience to obtain either pipeline or storage gas supplies and being remote controlled for system agility (affordable), and reducing the amount of emissions in this system (clean).

Figure 19: Transmission Capital Investment Plan



D. Distribution Asset Plan

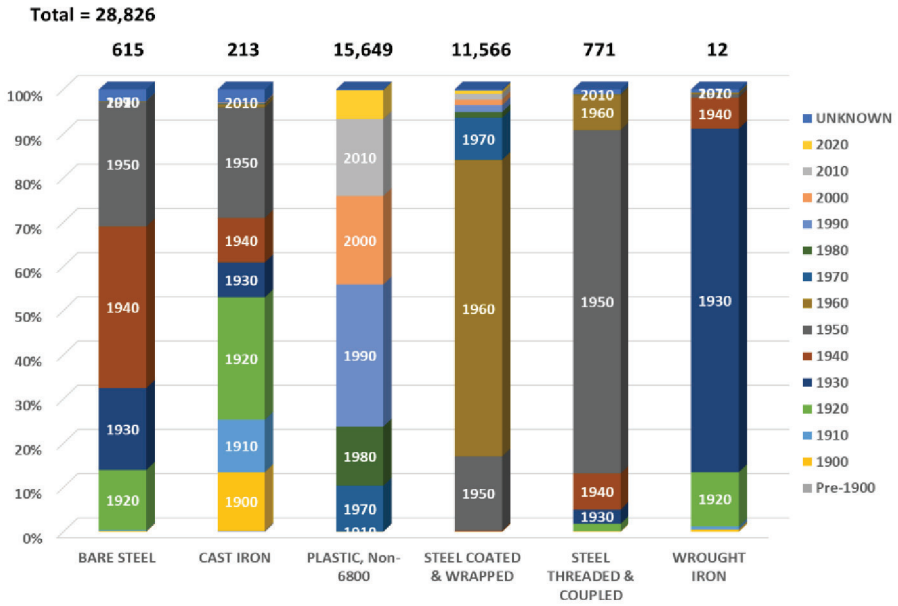
- Consumers Energy's distribution system moves gas at 60-400 psi from city gates through pressure regulation stations into neighborhoods and commercial and industrial ("C&I") districts to customer businesses and homes at service pressures that are less than 1 psi.
- Consumers Energy has approximately 28,368 miles of distribution pipeline, 516 miles of TOD pipeline, and 1.6 million services as of December 31, 2023.
- The Company's distribution mains are approximately 55% plastic, 43% cathodically protected steel, and 4% cathodically unprotected steel and vintage materials.
- The distribution system includes some of the Company's oldest facilities that are situated closest to customers. Replacing infrastructure to reduce risk and expanding remote monitoring in this area is critical. Vintage materials include cast iron, bare steel, and copper, which were installed from the 1890s through the 1970s. These are the highest-risk assets in this system and are the primary risk drivers. There are 1,611 miles of vintage materials with 112,157 services of vintage materials
  - In 2012, Consumers Energy launched the *Enhanced Infrastructure Replacement Program* ("EIRP"), targeting replacement of pipeline vintage materials over multiple decades.
  - Further, in 2017, the Company added the Vintage Service Replacement ("VSR") Program to eliminate identified vintage materials on services on a programmatic basis.
  - Removing vintage materials from the distribution system will improve customer safety and reliability by eliminating higher-risk materials from the system. This includes eliminating the standard pressure system.
- While leaks in this asset class are at a lower pressure compared to the transmission system, they are also located much closer to the public. To support expanded monitoring, the Company is implementing advanced leak detection and upgrading its Supervisory Control and Data Acquisition ("SCADA") system—this is further explained in the *Technologies* section.

1. DISTRIBUTION ASSET CLASS 10-YEAR FOCUS

- Reduce system risk and methane emissions while addressing system reliability and capacity. This will be accomplished by addressing aging or vintage infrastructure that is closest to the customers.
- Remediate vintage distribution main, standard pressure main, and vintage services to meet 2035 completion date. The annual targeted miles, as shown in Figure 20, is revised to balance with affordability and account for labor requirements, municipality project schedules, identified remaining segment projects, etc.
- Plan for resource availability to accommodate emergent and long-range requests for civic/asset relocation work consistent with actual 2019 – 2023 historical experience, or approximately 34.5 miles of gas distribution main installations annually.
- Remediation of line segments for which the Company has located pressure test records that conform to State and Federal Pipeline Safety regulatory requirements for traceable, verifiable, and complete documentation.
- Ensure funding for Distribution programs requiring changes to comply with new regulations, business growth, or technology obsolescence to avoid non-compliance or outdated/inefficient solutions.

The Company's system is comprised of a variety of materials with installations dating as far back as the early 1900s as shown in Figure 20 below[7].

Figure 20: Distribution Main by Materials and Installation Date (includes TOD)



Cast and wrought iron pipelines are among the oldest in the Company's distribution system. Nearly 65% of these pipeline types were installed pre-1940 making them over 84 years old. The age of the pipelines

[7] U.S. DOT PHMSA reported figures (March 2024)

introduces corrosion and cracking due to the degradation of the iron alloys (i.e., pipes rust and get brittle with age) and pipe joint design.

The following factors increase risk involved with a system that contains vintage materials:

- Bare steel (also called 'uncoated') pipelines are considered higher risk due to corrosion and cracking caused by age and lack of protective coating. External corrosion occurs on metal pipe due to soil and moisture conditions. Bare steel pipe is in direct contact with these corrosive conditions.
- Fluctuations of temperatures during the seasons, as experienced in Michigan, create additional risks. Once the ground freezes at low temperatures, pipelines are susceptible to frost heave causing new cracks to form and existing cracks to expand.
- Natural gas vapors are lighter than air and will generally rise and dissipate quickly. These vapors will move through the soil finding the path of least resistance. Frozen ground acts as a vertical barrier causing gas to gather and pushing it horizontally until it finds an opening (porous/cracked foundations, water/sewer lines) often leading into a building.
- In underground low-pressure gas pipelines, a leak may result in water infiltration (also called 'water ingress'). Groundwater enters the gas pipeline through a crack or corroded section of pipe, and eventually blocks the gas flow to the customer. In winter months, the water can freeze causing additional blockages, customer meter freeze-offs, and/or expanding existing pipeline cracks.

PHMSA classifies the highest risk materials[8], in order of risk, as:

- Cast iron
- Bare steel
- Threaded & coupled steel
- Wrought iron

These at-risk materials total 1,611 miles of main or approximately 5.7% of all distribution main miles. Of the remaining at-risk material miles, there are 1,394 miles located within the SP/MP system and 217 miles are in the HP system. Remaing miles for the highest risk materials are shown in Figure 22.

Another distribution integrity risk is pipes operating at standard (utilization) low pressure. Gas needs to reach each customer with enough flow rate and pressure to fuel equipment and appliances while staying below the maximum operating pressure for each segment within the system. The challenges of operating a standard pressure system are the dynamic flow and pressure changes due to varying customer demand within a narrow pressure operating range.

The standard pressure system operates at 8 - 12" water column ("WC") (about a ¼ psig). The pressure delivered to customers is the same pressure within the distribution pipeline from the upstream regulator station. The regulator station reduces the pressure to a level that allows the low-pressure gas to flow continuously to customers without the need for a second regulator located at the meter stand.

Since there is not a second regulator at every meter stand in a standard pressure system, an overpressure condition occurring on the distribution system can affect all customers served by the

[8] Pipeline Replacement Background | PHMSA (dot.gov)

system if the regulator(s) at the regulator station that controls the pressure for the system fails. This type of over-pressure incident occurred in 2018 in Merrimack Valley[9].

In addition to the risk of high-pressure incidents, a standard pressure system is also at risk of low-pressure incidents. This system struggles to operate at rated pressures on extreme cold weather days, respond to customer demand changes, etc.—and requires accurate and timely pressure control to meet deliverability requirements. If the rated pressure is not maintained and drops below 7" WC, customers may experience heating and other appliance problems due to low gas pressure.

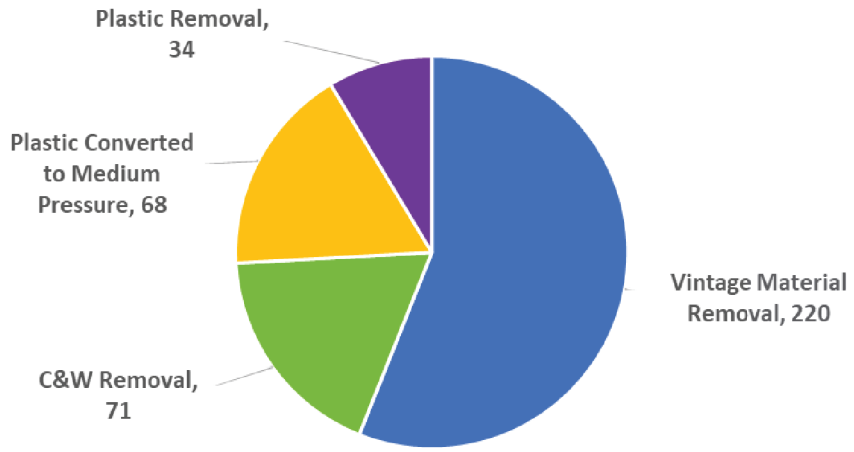
Other factors that can contribute to low gas pressure include standard-pressure portions of the system, with largely vintage materials, which are susceptible to fluid infiltration from the ground. This fluid can travel through the system, including to customer meters.

Additionally, in freezing temperatures, this fluid may seal the orifices of the meter and/or regulator and interrupt gas flow. This poses a risk to customers during the heating season. Furthermore, removal of this fluid requires maintenance of "drip" points on the standard-pressure system with additional costs for removing/pumping the fluids.

The Company's vintage miles cover all but approximately 173 miles of the 393 remaining miles of the standard-pressure system. The 173 miles are made up of 71 miles of coated and wrapped steel and 102 miles of plastic pipe. A portion of the plastic pipe, 68 miles, is planned to be converted from standard-pressure to medium pressure. The remaining 105 miles of plastic and the coated and wrapped steel will be removed/retired.

Therefore, to improve customer safety and reliability and improve system efficiency due to higher operating pressures, the 105 miles of non-vintage standard low-pressure pipe will be added into the vintage remediation goals with the intention of eliminating the standard pressure system by 2030.

Figure 21: Standard Pressure System (in miles)



[9] Merrimack Valley NTSB Report: https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1902.pdf

2. DISTRIBUTION ASSET MANAGEMENT

Overview of the Current Main and Service Remediation Program (i.e., EIRP, VSR)

The *Pipeline Inspection, Protection, Enforcement, and Safety Act* ("PIPES") of 2006, Public Law No: 109-468, mandated that PHMSA, within the U.S. Department of Transportation, prescribes standards for *Distribution Pipeline Integrity Management Programs* ("DIMPs").

Federal DIMP rules were subsequently established under Subpart P of the U.S. Code of Federal Regulations, Title 49, Part 192. The Company's current replacement program (part of Consumers Energy's DIMP to remediate at-risk cast iron, bare steel, and threaded and coupled steel) is the EIRP.

The EIRP was launched in mid-2012, with the first full program year in 2013. Through all programs, the Company remediated 373 miles of cast iron, 413 miles of bare steel, 298 miles of threaded and coupled steel, 10 miles of wrought iron, 1 mile of x-trube, 38 miles of Low Frequency Electric Resistance Welded ("LFERW"), for a total of 1,134 miles.

Figure 22 shows miles of historic Vintage Material remaining on the system based on data submitted on and supplemental data to the Distribution DOT annual report for that year.

Figure 22: Vintage Miles of Main Remaining by Material Type

Figure 23 shows the total miles of SP/MP Vintage and HP Vintage main remaining on the system at the time of the 2023 DOT Report submittal and is represented by the first two bars in the figure. Data is specific to the EIRP Program and is based on the EIRP Annual Performance report data. The totals may not sum to the individual years due to rounding.

Figure 23 shows a breakdown of the remaining EIRP program miles by material, pressure class, and TOD pipe as of February 1, 2024.

Figure 23: Remaining EIRP Program Retirement Miles

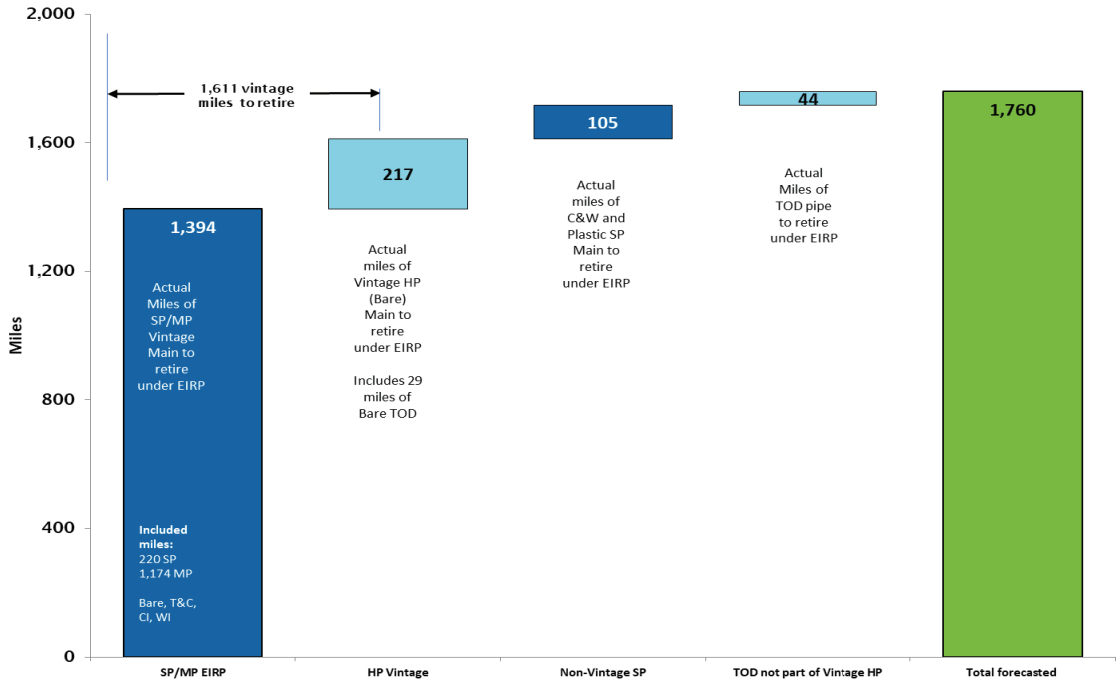
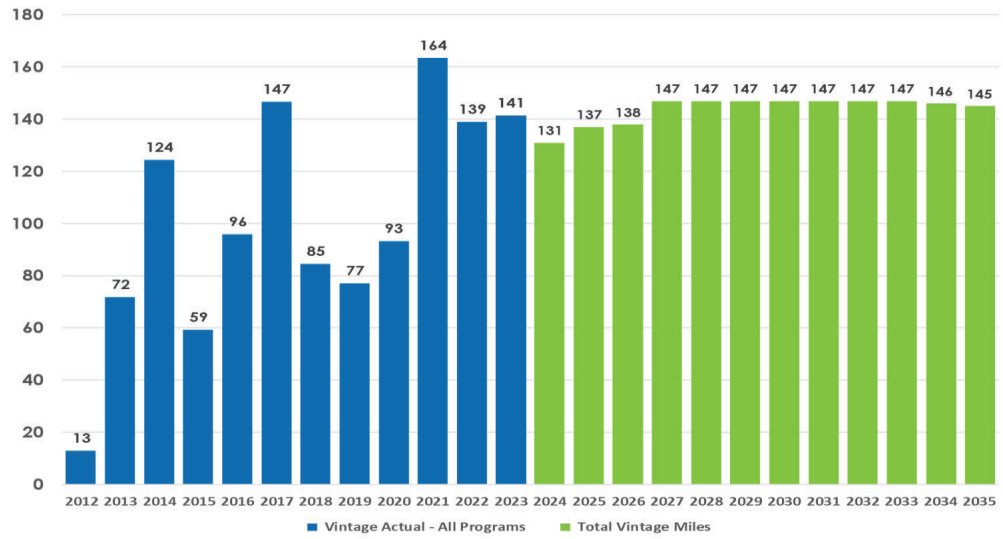


Figure 24 represents the historic 2012-2021 vintage miles retired by all programs and illustrates the new plan for the 1,726 remaining miles to retire from 2024-2035.

Figure 24: Retired Vintage Miles for All Programs



3. OVERVIEW OF DISTRIBUTION SERVICES AND VINTAGE SERVICE REPLACEMENT PROGRAM

The distribution system includes approximately 1.6 million service lines that connect the distribution mains to homes and businesses. Service lines can contain at-risk materials and are dispersed evenly across the system.

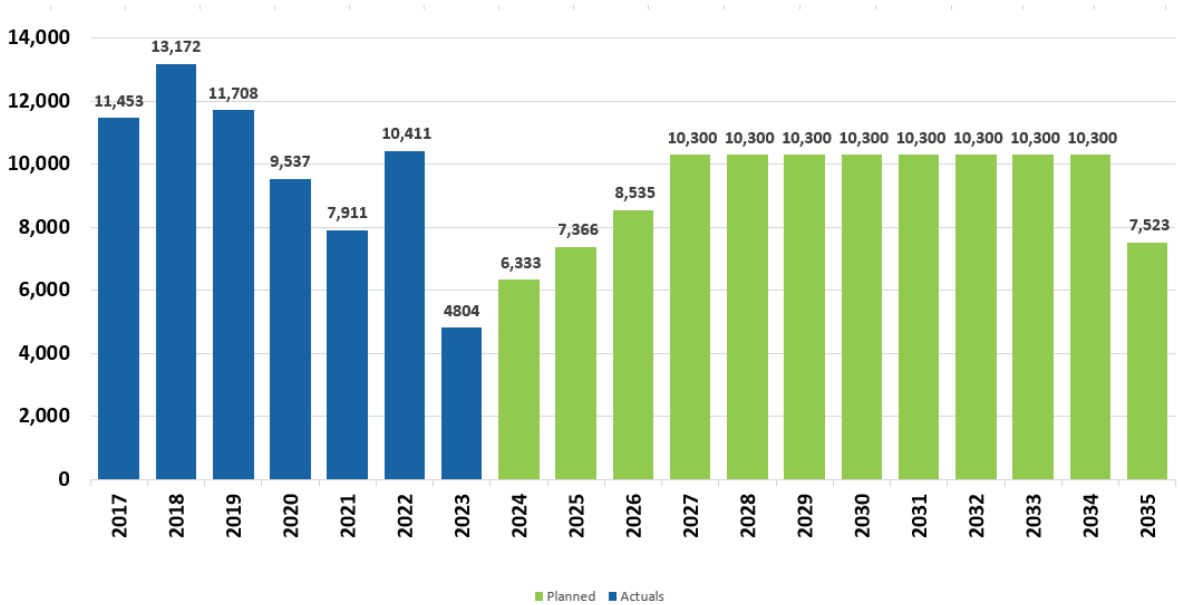
As of December 31, 2023, the system contains approximately 95,829 copper services, or 5.9% of all services and, in a much smaller quantity, the system also contains 6,556 bare steel services and 9,772 services for which the material is unknown.

Consumers Energy launched a Vintage Service Replacement (VSR) Program in 2017. Similar to vintage main replacement, the Company has **streamlined planning across all vintage remediation programs and leveraged construction efficiencies** to minimize customer impact to achieve completion by 2035.

Vintage services are classified into three groups. These services could be replaced by various programs including VSR, Civic, Leak, etc.

1. **In-Grid VSRs** are vintage services attached to a vintage main located within an EIRP project.
2. **Proactive In-Grid VSRs** are vintage **services** attached to a non-vintage main located within an EIRP project.
3. **Proactive Out-of-Grid VSRs** are **vintage** services located outside of an EIRP project.

Figure 25: Remediation Plan by Category for Vintage Services



4. MAINTAIN PACE OF VINTAGE MATERIAL REMEDIATION

The Company collaborated with external stakeholders, and concluded that completing EIRP and VSR programs by 2035 best balanced customer safety and reliability with affordability.

Benefits to Customers to Remediate Vintage Material

- A target of 2035 positions the Company to remove the risk from assets, and ensures the safety of customers and the public while balancing with affordability.
- Minimizing impact to customers using the grid approach. This approach reduces mobilization and demobilization to the same or nearby neighborhoods.
- Remediating vintage materials reduces methane emissions. Methane studies estimate that cast iron pipes leak almost 23 times more methane than plastic pipes, while unprotected steel leaks almost 10 times more.
- Improving local coordination with municipalities to better align timing of Company-planned work with public works projects.
- Limiting customer safety and reliability risk by more rapidly eliminating higher-risk vintage main pipe and services from the system.
- Improving system efficiency by reducing standard pressure on the system.
- Lowering gas losses and reducing methane emissions into the atmosphere.
- Reducing O&M costs for leak repair and survey as provided in the annual EIRP Performance Report.

5. FUTURE INFRASTRUCTURE RISK REDUCTION PROGRAM CONSIDERATIONS

Consumers Energy is identifying the next areas of high-risk after completion of the vintage material replacements. Currently under consideration are the following higher risk areas:

Services

- The Company has approximately 10,000 vintage service stubs made of copper, bare steel, and X-Trube steel on the system. Service stubs are a result of historical maintenance where a service was not retired or replaced due to limited access to the main.
- Replace metallic services currently not cathodically protected, as the cost of replacement of that service with plastic would be more economic than the cost to add cathodic protection.
- X-Trube services are of 1950-1960s vintage. X-Trube is protective-coated thin wall steel pipe. This material has the highest leak rate. Consumers Energy has approximately 100,000 X-Trube services on the system.

Mains

- Replacement of metallic mains that are not cathodically protected, as the cost of replacement of that main with plastic would be more economical than the cost to add cathodic protection. Cathodic protection did not begin until 1970, but Coated and Wrapped (C&W) mains were installed on the system since the 1950s. These mains therefore were used up to 20 years without cathodic protection. C&W unprotected pipe within the date range above and currently cathodically unprotected pipe would be evaluated and criteria developed to determine the focus area.

- Transmission Operated by Distribution (TOD) main on Consumers Energy's system that is not replaced under EIRP or other programs must be replaced to lower the SMYS below 20%, which addresses MAOP concerns and reduces operating costs.

6. REGULATOR STATIONS, ODORIZERS, AND STANDS

The Company operates and maintains approximately 657 regulator stations, 1,200 regulator stands, and 100 odorizers as of December 31, 2023. These assets regulate natural gas pressure to ensure safe delivery to customers. Regulator stands include 1" regulator units that feed smaller distribution systems.

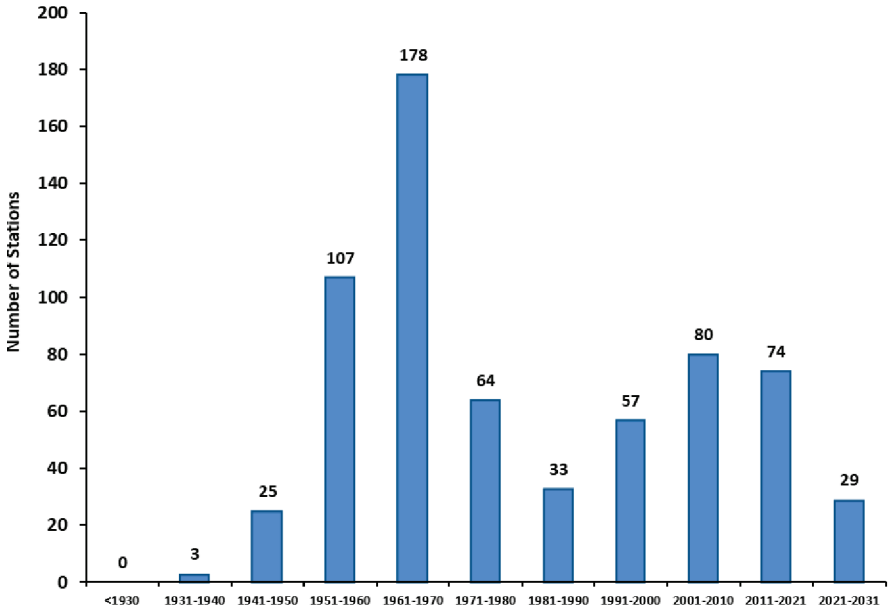
Regulator Stations

Regulator stations reduce pressure supplied from a higher-pressure system, including 2" and larger pipe that feeds a distribution region.

The 10-year goal for the regulator station fleet is to ensure 60% of all regulator stations are not in service longer than 50 years.

Investments made into regulator stations improve safety and maintain the integrity of the asset. These investments include over-pressure protection and SCADA monitoring equipment. Approximately half of the regulator stations were installed before 1971, as shown in Figure 26[10].

Figure 26: Distribution of Regulator Station in Service Dates



The asset life for a regulator station is approximately 50 years. To maintain an average lifespan of 50 years across the fleet of regulator stations, the Company must rebuild 8-12 stations per year at an average cost of $3 million per regulator station, while retiring four standard pressure serving regulator stations. This equates to an average program cost of approximately $30 million per year in station rebuilds.

[10] GIS database

Adding more distribution systems monitoring through SCADA, particularly at regulator stations and odorizers requires technology updates, including upgrades to the SCADA historian and monitoring systems.

These enhancements allow for additional data points to be monitored along with additional storage for that data. See the *Technology* section for additional discussion on SCADA monitoring.

Odorizers

Odorizers are assets that add odor to the downstream gas system, which is a critical safety element required by code.

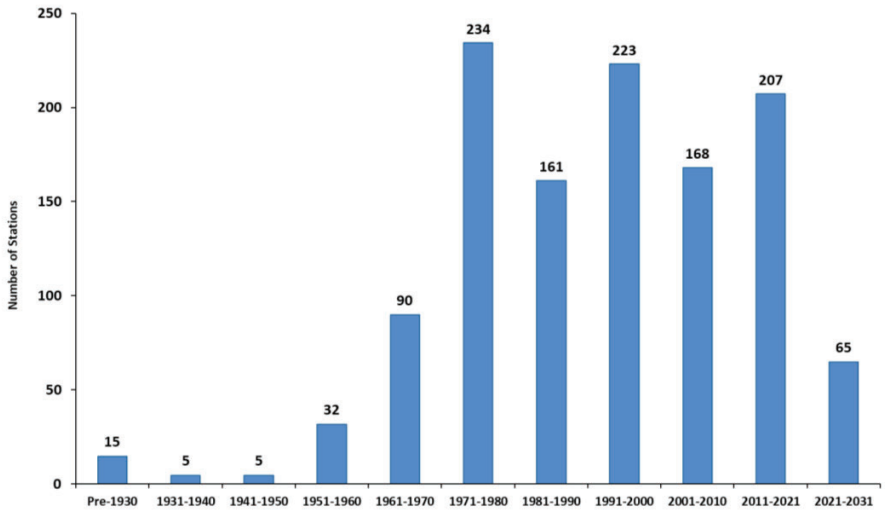
Odorizers are co-located at city gates and transmission valve sites, as required, to comply with State and Federal Pipeline Safety regulatory requirements. They deliver a potent smell notifying someone with a normal sense of smell of a gas leak. The year-over-year goal for the odorizer fleet is to ensure odorizer pumps are 30 years old or less, and that any exceptions are planned for replacement.

Currently, all odorizer pumps in the system are less than 30 years in service. The Plan allows for one odorizer station to be rebuilt per year independent of a city gate rebuild. This is a stable and reasonable trend that should continue for the next 10 years, maintaining all pump in-service dates less than 30 years.

Regulator Stands

Approximately 12.6% of the regulator stands were installed before 1971, as shown in Figure 27. Due to the age and condition of regulator stands, the Company plans to continue investments in these assets comparable to historical years.

Figure 27: Distribution of Regulator Stands Age Distribution



7. LEAK REMEDIATION

Employee and public safety are top priority. Consumers Energy uses regular leak surveys to identify and remediate potentially hazardous gas leaks.

As discussed above, a potent odorant chemical is delivered to the system which allows customers and other third parties to identify gas leaks before they become hazardous. Once notified of a potential leak, a response is provided within 30 minutes and a leak analysis is completed to determine the appropriate leak classification for repair scheduling.

Factors used in the analysis include gas concentration readings, distance of the leak from the outside of a building, and potential that gas could migrate into a building.

Leak repair scheduling is required per code—Michigan Gas Safety Code 192.703, 192.709, 192.711 and Michigan rules 318 and 327.

Minimum requirements for distribution system leak survey programs outlined in 49 CFR 192.723 are:

- At least once each calendar year, at intervals not exceeding 15 months, a leak survey using leak detecting equipment must be performed in business districts at all locations. This provides an opportunity to locate gas leaks (e.g., gas, electric, and water system manholes and sidewalk/pavement cracks).
- Outside of business districts, leak surveys must be performed at least every five years. For cathodically unprotected distribution lines, leak surveys must be conducted every three years.

Table 4 provides an explanation of how the Company currently classifies leaks on the gas system,

Table 4: Leak Classification at Consumers Energy

Leak Classification and Evaluation of Leak Severity and Prioritization of Repairs	
Leak Classification	**Definition**
Immediate Action	• Repair immediately (temporary or permanent repair) OR • Take corrective action to reduce the hazardous condition to a level which the leak can be reclassified as a Scheduled Action
Scheduled Action	• Repair or investigate the leak within the specified timeframe: ○ Distribution – 4 months ○ T&S – 4 months • A documented classification is required for each re-investigation. • Permanent repair must be completed within the specified timeframe. ○ Distribution – Within one year of the leak being found ○ T&S – As soon as feasible, based on re-investigation, ongoing review of system outages, and upcoming projects
Deferred Action	• Re-investigate the leak within one year of the date the leak was found. • A documented classification is required for each re-investigation. • If deferred again, re-investigate within a year from the new date.

In January 2025, the Company anticipates new requirements from PHMSA proposed regulatory amendments directed by the *Protecting the Infrastructure of Pipelines and Enhancing Safety Act of 2020* to reduce methane emissions from new and existing gas transmission pipelines, distribution pipelines, compression facilities, and underground natural gas storage facilities.

PHMSA's Leak Detection and Repair or "LDAR" regulations are pending. The anticipated effective date for the proposed regulatory amendments is June 2025. As currently understood, full compliance to the regulations is required by January 2028.

As of December 2023, the Company has approximately 5,622 total active leaks. In preparation for the anticipated PHMSA rulemaking, the Company is assessing the current leak backlog and how to best address all new leaks.

To balance our pace and prioritization of system needs with affordability, the Company will prioritize and remediate across all programs, such as the leak renewal and vintage material programs, to reduce overall risk.

8. SYSTEM AUGMENTATION FOR RELIABILITY

During periods of high customer demand in cold temperatures, areas are identified with a need to address low delivery pressure or service losses to customers.

System augmentation projects are designed and constructed to enhance capacity and maintain service to customers in these areas.

Examples of large augmentation projects currently planned for 2024 through 2026 include:

- Connecting the existing medium pressure distribution system to a new outlet at the Orion city gate. This requires construction of approximately 1,100 feet of six-inch medium pressure plastic main. The connection to the new outlet enhances capacity and resilience in an area where growth could create low pressure conditions. This project is planned for completion by November 2024.
- Installation of approximately 1,700 feet of four-inch plastic medium pressure main on Rives Junction Road and 1,300 feet of two-inch medium pressure plastic main on Parnall Road in the Jackson area to construct a looped gas supply to reduce risks of low pressure as well as improve resilience on this main. The project is planned for construction during 2026.
- Installation of approximately 1,100 feet of six-inch plastic medium pressure main on Belsay Road that connects with existing two-inch medium pressure main on Burton Estates Drive east of Flint. This project will address low pressure conditions experienced during the winter of 2022-2023 in this area, and improve resilience in this area. Construction is planned to occur during 2025 for this project.
- The Beaverton Shaffer Road east of Alamando Project involves the construction of 7,050 feet of 12-inch steel high pressure main that will be constructed parallel to existing six-inch high pressure main out of the Coleman Beaverton city gate station. This capacity expansion will improve delivery pressure in an area of growing demand. This project is planned for construction during 2025.
- The Crooked Lake Road - Latson Road Project will construct 3,000 feet of six-inch medium pressure plastic main to create a looped system near the end of two existing distribution main systems. This augment project will improve deliverability by creating a back feed and increase the system pressure. The resilience of the system will also be enhanced by the looped system. This project is planned for construction in 2024.
- The Galesburg - Celery & River Street project will construct a 6,900 feet of eight-inch-high pressure steel main from the Galesburg city gate outlet to Comstock Avenue & Celery Street in the Kalamazoo area. This will create a looped system from the Galesburg city gate high pressure outlet, increase the delivery pressure and reduce the risk of customer outages due to damage or failure. This project is planned for construction in 2024.

9. MAOP RECONFIRMATION AND COMPLIANCE PROJECTS

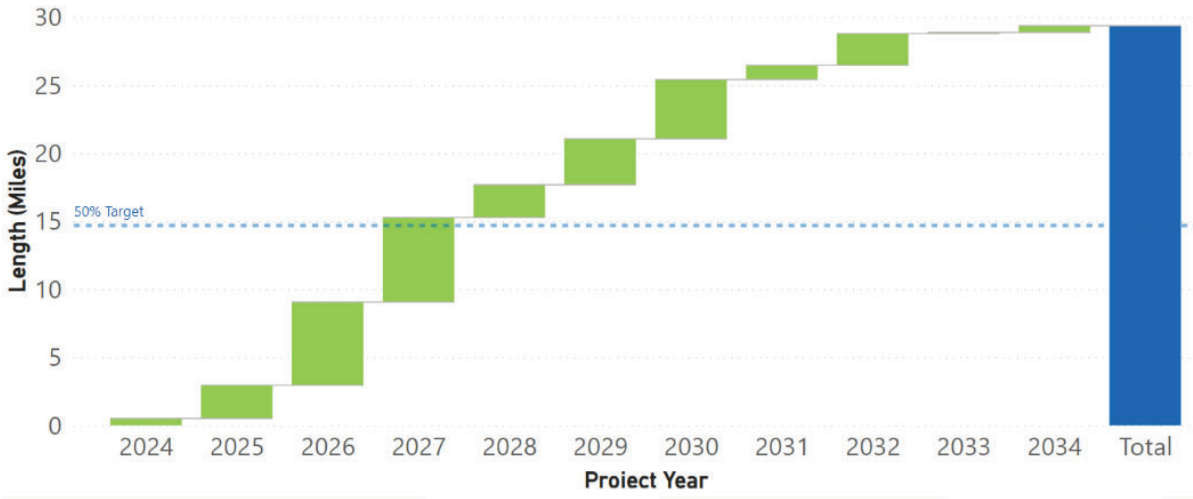
Compliance with State and Federal Pipeline Safety regulatory requirements support the Company's goal of providing safe and reliable natural gas service to customers. Various distribution line segments are being evaluated for compliance with MAOP standards.

Per Federal requirements, the Company must operate gas distribution line segments in a manner consistent with maximum allowable operating pressures. This requires reconfirmation of pressure test records and remediate line segments where no pressure test records exist that meet PHMSA's expectations for traceable, verifiable, and complete documentation.

Compliance milestones related to MAOP projects include a requirement to complete all required actions on 50% of the pipeline mileage subject to MAOP reconfirmation requirements by July 3, 2028, and complete all required actions on 100% of the pipeline mileage subject to MAOP reconfirmation requirements by July 2, 2035. A listing of currently planned MAOP projects is provided in Appendix F.

In addition to the work being done by the Company to evaluate compliance with MAOP standards, it was determined that Line 1080, which serves customers to the west of Kalamazoo, must operate at a lower pressure to comply with Federal requirements. Pipeline modifications are planned for construction during 2025 and 2026.

Figure 28: Planned MAOP Distribution Miles Reconfirmed



10. CUSTOMER METERING

The Company routinely purchases meters, regulators, and related equipment for serving new business connections, the Routine Meter Exchange Program (an MPSC requirement), service renewal meter move-outs, and normal replacement of obsolete or broken meters.

The Company currently uses temperature-compensated diaphragm (regulated and top connect) meters, rotary meters, and purchases gas meter communication modules ("GCM"), gas electronic volume corrector units ("EVC"), and testing equipment.

From 2015 to 2019, the Company installed GCMs manufactured by Itron on more than 1.8 million existing gas meters as part of the AMI and AMR projects. Gas smart meter technology using cellular communications, like the AMI solution deployed for electric customers, was not available.

In 2020, Itron customers, including Consumers Energy, received end-of-product-life notices for the GCMs and diaphragm meters currently in use.

The Itron announcement regarding the end of life for their diaphragm meter product line impacts approximately 1,600,000 installed regulated diaphragm ("RM") customer meters. These meters have a different connection method compared to the top connect ("TC") diaphragm meter, and will require a meter stand rebuild to accept a TC meter. In view of this, the Company began proactively rebuilding RM meter stands in 2020, starting with multi-meter stands.

The new meter stands include a meter bypass that will improve safety and reduce customer interruptions during exchanges, accept the industry standard top connect meter, and will enable the Company to improve multi-meter installation designs by allowing the installation of one master regulator to serve multiple meters.

Due to the gas metering technology obsolescence announcements from Itron, the Company is investigating various scenarios, including projected costs and schedule, for conversion of all RM meter stands to TC meter stands. The conversion will require a new TC meter and regulator be purchased to replace the RM meter.

While investigating various metering scenarios, there is an emerging trend among natural gas utilities to use single path ultrasonic gas smart meters ("USM") for customer metering. This type of meter offers many advantages, including improved measurement accuracy, remote shut-off capabilities, and hi-flow detection.

In 2024, the current USMs available do not include a cellular communications option but that option is expected to be offered in 2025. The Company will continue to evaluate changes in metering technology to incorporate the migration of customers to gas smart meters into the scenarios evaluated.

Installation of TC meter stands will provide the opportunity for future gas smart meter technology upgrades with minimal field changes. The different types of meters, including an example of a residential gas smart meter (Itron Intellis Ultrasonic Meter (USM), are shown in Figure 29.

Figure 29: Meter Types

Regulated Meter (RM) | Top Connect (TC) Meter | Top Connect (TC) Meter w/Bypass | Itron Intellis USM

11. NEW BUSINESS

The New Business Program consists of adding infrastructure to serve new commercial, industrial, and residential customers. These projects are required in response to customer requests for new gas service.

Customers who request service share in the construction costs with the Company based on the appropriate tariffs approved by the MPSC. During 2022, customers contributed approximately $7 million to new business project costs, increasing to more than $10 million in 2023.

The program costs include the cost of installing mains, services, regulators, and the cost of meter stands to serve new customers. Between the years 2019 and 2023, the Company connected 37,909 new gas services to its gas distribution system.

The Company uses forecasting data from multiple sources to forecast and plan for new business growth. During July 2022, the University of Michigan Research Seminar in Quantitative Economics published its long range economic and demographic projections for Michigan through 2050.

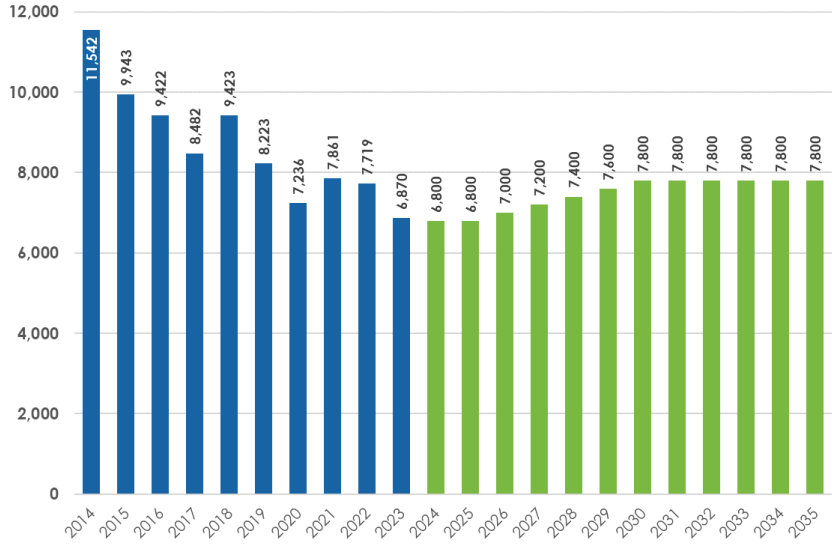
Michigan experienced declines in population during 2020 and 2021 and was expected to decline again in 2022. Population levels are projected to grow through 2046, then begin declining each year through 2050.

During the 2020 to 2050 period, the number of households in Michigan is forecasted to increase to 432,815 households, or 10.9%. The pace of household growth will exceed the pace of population growth as single person households become a larger share of total households due to aging demographic characteristics. Growth rates in many of the counties served by the Company's gas utility should exceed the statewide average. For example, Macomb County and Oakland County are projected to experience population gains of more than 10%.

Based on recent analysis of housing market data, the Company believes that service connection volumes for 2020 through 2023 represent activity levels that are negatively impacted by numerous factors since the onset of the COVID-19 pandemic. This includes periods of construction labor constraints, inflated lumber prices, shortages in electrical transformer supply, and increasing mortgage interest rates. Even prior to 2020, it is generally accepted that the pace of new housing construction in Michigan has not kept pace with demand. As a result, current constraints on the supply of available housing make it difficult for new households to find affordable housing.

The Company reasonably expects annual connection volumes to grow incrementally at a modest rate of approximately 200 services per year beginning in 2026 and stabilizing around 2030 as shown below in Figure 30. Housing starts economic indicator projections provided by S&P Global Market Intelligence in May 2024 (Michigan forecast) and the National Association of Home Builders in April 2024 (U.S. forecast) both support growth in projections of housing construction activity starting in 2025.

Figure 30: New Business (Number of Service Connections)



The Large New Business Program includes new customer connection projects where the estimated infrastructure cost exceeds $500,000, a facilities agreement is required for unpredictable operations, or the connection is deemed necessary for special tracking and therefore included in a separate sub-program.

Projects are generally created under this program when the requesting customer has signed a contract with the Company documenting the load requirements and revenue expectations.

There were two projects completed under this program in 2024:

- A 1-mile extension of 8” high pressure steel main to serve a battery manufacturing facility in Marshall, with an estimated annual usage of 2 billion cubic feet (Bcf).
- A new plant that supports the semiconductor industry in Hemlock, extending approximately 4,500 feet of 6” high pressure steel main to support an estimated 0.5 Bcf of added annual gas usage.

In 2025, there is an approximate 200-foot extension of 8” high pressure steel main to serve a natural gas-fired electric generation facility expansion in the Lansing area, with an estimated annual usage of 2 Bcf.

12. ASSET RELOCATION CIVIC IMPROVEMENT

According to the 2023 Report Card for Michigan’s Infrastructure, published by the Michigan Section of the American Society of Civil Engineers (or “ASCE”), Michigan is making progress in reversing underinvestment in the state’s infrastructure.

State and Federal funding sources have included $3.5 billion in bond funding from the *Rebuilding Michigan Program* and $4.7 billion from the *Building Michigan Together* Plan. The 2021 Bipartisan Infrastructure Law also provides $11 billion to address needed infrastructure projects. The ASCE’s 2023 Michigan Infrastructure Report Card assessment shows modest improvement in the overall grade from a D+ in the 2018 report card to a C- in the 2023 report card. Roads and Stormwater infrastructure grades have improved from a D- in 2018 to a D in 2023.

Civic Improvement Relocation projects frequently involve replacement of vintage mains and services, avoid third party damage to non-vintage facilities, and reduce the potential for leaks when infrastructure contractors are working around vintage main.

The annual replacement of vintage mains and services are documented as part of Attachment 9 *Non-EIRP Distribution Main Replacement Project Metrics*, which is included in the Company’s enhanced infrastructure replacement annual reports.

From 2019 - 2023, more than 181 miles of metallic pipe was retired through the construction of Civic Improvement projects.

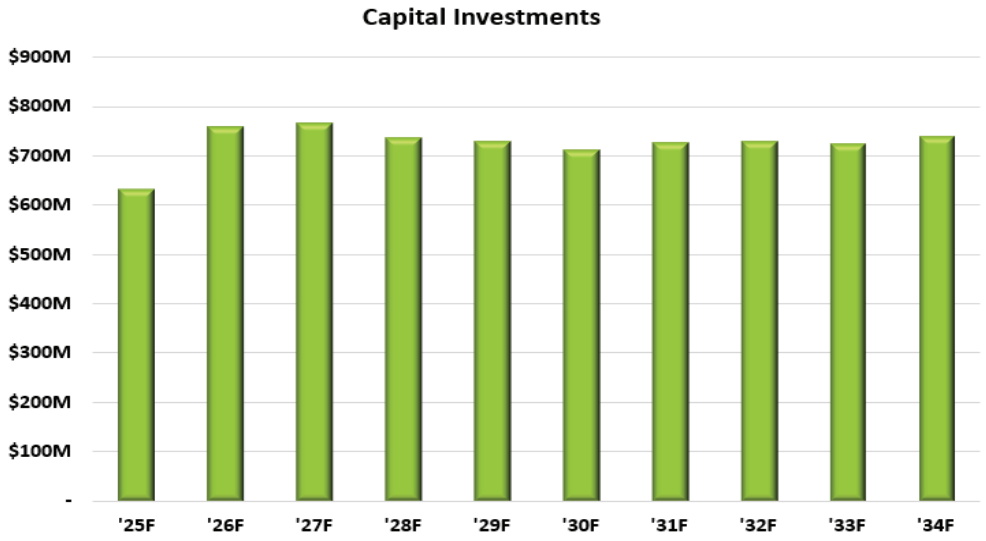
13. DISTRIBUTION ASSET FINANCIALS

Consumers Energy’s largest capital increase is due to vintage material remediation. The Company believes it can lower remediation costs through economies of scale and work management improvements.

With the extension of the EIRP and VSR programs to 2035, the Company expects the total main and services remediation to cost approximately $5.2 billion. The capital investment plan for the entire distribution asset class is shown in Figure 31.

Overall, this investment plan for the distribution asset class aligns with the objectives by **reducing asset risk** that is closest to the customer (safe), ensuring the **system is able to deliver gas as required** (reliable), **balancing the pace of system improvements** to preserve customer affordability (affordable), and **reducing the amount of emissions** in this system, which equates to more than one-third of the Company's methane emissions (clean).

Figure 31: Distribution Capital Investment Plan



V. Operational Capabilities

Operational capabilities surround people, process, and technology to enable achievement of the 10-year objectives, goals, and outcomes.

A. People – Talent and Workforce Approach

The Company is focused on how to safely deliver for customers by ensuring Consumers Energy has the right people, with the right skills, at the right place and time.

1. INTERNAL RESOURCES

- The Company is placing a **strong focus on hiring skilled trade workers and engineers, and creating a diverse, equitable and inclusive employee experience** to ensure the Company is attracting and retaining the most qualified candidates.
- To prepare for the skills of today and tomorrow, Consumers Energy has developed a **full-scale Gas City Training Village** that trains coworkers through real-time, hands-on situations and continue relentless focus on making safety the top priority.
- To prioritize asset protection, the Company is **evolving cybersecurity skills** as technology becomes more integrated with assets. As customer expectations shift, the Company will need a workforce skilled in leveraging the power of data, and empathy, to meet customer needs.

- More than 1,400 coworkers inspect, maintain, and build our natural gas system. This framework facilitates the **matching of coworkers, capabilities, and qualifications to the requirements of the business to minimize the risk and costs of turnover**. The Company also developed a competitive Michigan workforce of approximately 500 coworkers that is focused specifically on the natural gas infrastructure.
- The Company focuses on attracting, developing, and retaining engineering talent through the Company's Entry Engineer Program and Engineering Intern Program. These programs build technical engineering and design capabilities, ultimately ensuring adequate pipeline for engineering talent specific for the Company's natural gas system.

2. DIVERSITY, EQUITY & INCLUSION IN THE ENTIRE TALENT LIFECYCLE

As one of Michigan's largest employers, Consumers Energy is building a world-class, inclusive workforce where diverse groups of people feel safe and welcome at work. The Company workforce strives to be wholly reflective of the communities it serves. To drive innovation and provide the best energy products, Consumers Energy is creating a pipeline to become an employer of choice for under-represented communities in high demand occupations. To ensure an adequate talent pipeline, multiple forums are used to attract, retain and grow people described in detail in Appendix D. A few examples include:

- **Diversity of our line workers**: To ensure every co-worker has an equitable opportunity to succeed, talent pipeline programs are built in diverse communities to increase equitable access to our skilled-trade positions.
- **Connecting youth with energy innovation**: Over 300 Consumers Energy employees volunteer their time as Talent Ambassadors with K-12 student throughout the communities it serves to discuss career pathing and other utility-related professional development opportunities.
- **Apprenticeship training programs**: Consumers Energy offers in depth training programs designed to further the skills, knowledge and ability of its existing workforce including certification program recognized by the Department of Labor as a certified Apprenticeship.
- **Workforce development opportunities**: Development opportunities include community engagement, hardware manufacturing, hardware/software design, data analytics, installation, and operations. To attract talent from the communities served by this project, Consumers Energy will work to better understand workforce challenges in specific areas and find ways to address concerns for skilled labor and professional careers.

Regarding skilled labor, the project will involve the installation of new hardware throughout the service territory. Consumers Energy and its technology vendor, Utilidata, will work with labor organizations on new training material and field demonstration guides intended for metering technicians.

Regarding professional careers, Consumers Energy will work with institutes/schools within Michigan on coursework that addresses artificial intelligence predictive modeling for the distribution grid. As part of this process, Consumers Energy will explore the possibility of creating an internship program that places students that have completed the relevant coursework into data analytics, software design, or grid modernization teams.

3. DIVERSITY, EQUITY & INCLUSION MOVEMENT STANDS

To quantify this work, several DE&I Movement Stands exist including Culture, Talent, Supplier Diversity and Philanthropy. These stands include multi-year goals that support our strategy, are aligned with our Executive DE&I Council, and represent measurable aspirations. See Appendix E for further information.

Table 5: CE DE&I Movement Stands

Our Movement Stand	2024 Measurement	2025	2028
Culture: The Company includes and values people of all backgrounds in the company and culture.	+2 increase from 2023 score on DE&I Index	+2 over YE	93
Talent: Every **current** and future coworker has an equitable opportunity to succeed.	Engineering roles at/above labor market availability: 49%	54%	79%
	Operational roles at/above labor market availability: 53%	58%	63%
Philanthropy: The **Company** creates equitable, sustainable change to support social justice initiatives throughout Michigan.	$5 million	$15M	$40M
Supplier Diversity: The Company will **double** its spending with diverse suppliers to achieve 1st quartile.	11.90%	14%	1st Quartile

4. ENERGY AND ENVIRONMENTAL JUSTICE (EEJ)

Consumers Energy is dedicated to our purpose to achieve world class performance delivering hometown service, measured by a triple bottom line - **People, the Planet, and Michigan's Prosperity.** This commitment guides decision making for an equitable clean energy future.

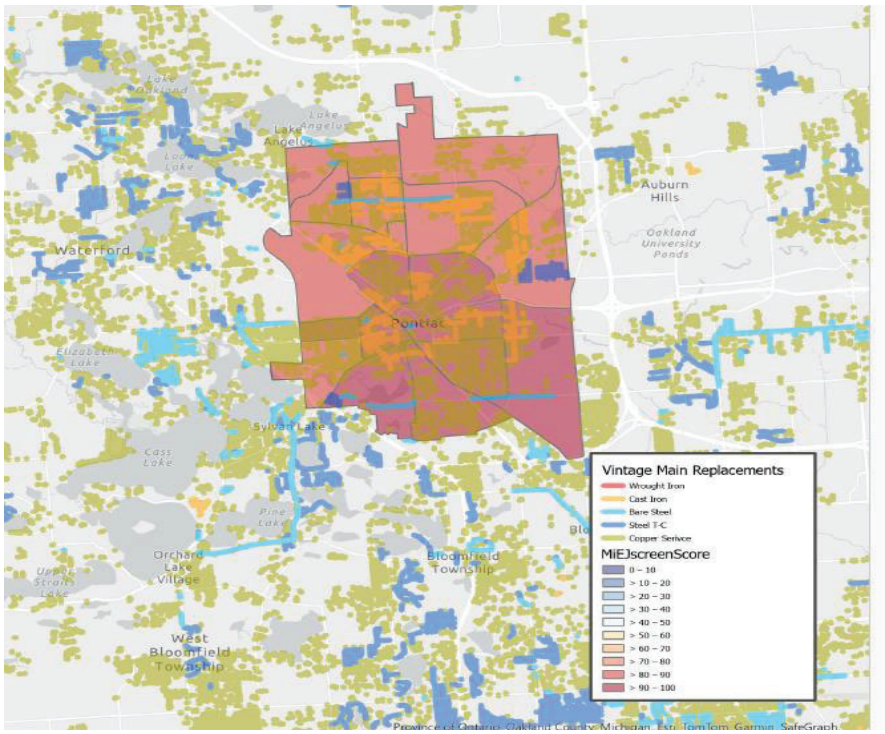
CMS Energy is dedicated to engaging communities to understand unique needs and provide platforms for collaboration. Responsibility for EEJ is designated to the Diversity, Equity and Inclusion Department as well as our Environmental Quality and Sustainability Department.

In addition, Consumers Energy is currently developing a comprehensive EEJ Strategy Playbook, to guide both internal and external actions, and emphasize the importance of enhancing more equitable and inclusive community stakeholder engagement pathways.

The Company is assessing how to best incorporate EEJ considerations into the overall planning process across all asset classes.

As shown in Figure 32, the MiEJScreen tool, operated by Environment, Great Lakes and Energy (EGLE), will be used to identify the highest impacted areas within the Company's service territory. Regions with scores of 80+ is defined as an EEJ community. The Company is seeking to better understand factors including vintage materials and vintage systems in these areas.

Figure 32: MiEJScreen illustration - Pontiac



B. Process – Operating System Approach

The Company is committed to operational excellence. At Consumers Energy this means achieving a state of performance that enables the Company to deliver on its purpose.

Through application of Lean principles (The CE Way), work management enhancements, and the Gas Safety Management System, the Company is transforming how it operates to improve performance, customer experience, identify efficiencies in the business, and minimize risks.

1. THE CE WAY

Consumers Energy's purpose of 'CMS Energy: World Class Performance Delivering Hometown Service' means ensuring the Company delivers safely, reliably, affordably, and with the highest quality. Examples of performance improvements can be seen across the organization because of the Company's Lean journey.

In 2016, Consumers Energy began its Lean journey, The CE Way, to provide the best value for customers through a culture of continuous improvement. This is the adaption of the Company's lessons learned in manufacturing and other industries applied to design, construction, and operations of utility assets to continuously improve safety, quality, cost, delivery, and morale.

In 2017, the Company launched the 4 Basic Plays (Visual Management, Operating Reviews, Problem Solving, and Standard Work) as a prioritized approach to begin implementing the CE Way. These basic plays establish a strong capability for delivering value to customers and achieving breakthrough performance. The CE Way Basic Plays are interdependent and achieve maximum effectiveness when implemented together.

The next step in our CE Way journey is to combine data with the Basic Plays to deliver a CE Way + Digital approach. Combining the CE Way with data increases the speed and accuracy of decision-making.

2. WORK MANAGEMENT AND CONTRACTOR OVERSIGHT

As part of the operational excellence process, **work management is a key to successful execution of this Plan**.

Work Management

Work Management provides a well-structured, predictable, and repeatable process, and describes the lifecycle from intake and system planning all the way through Engineering, Scheduling, Field Operations, and Closeout.

Effective work management eliminates defects and maximizes efficiency and productivity. The Company is assessing how digital tools in every step of the end-to-end process can further enhance productivity and cost efficiency.

Digital tools are an important component of eliminating unnecessary steps to simplify processes and make them as efficient as possible. See Technology for specific digital investment plans.

Enterprise Contractor Oversight

Enterprise Contractor Oversight ("ECO") is a key initiative for the effective oversight of contracted work for higher risk (level 3 & 4) activities.

ECO provides a framework for governance, performance monitoring, and controls of contractor work across the entire Consumers Energy Enterprise, including gas, electric and project management. The goals of ECO are to:

- Design and implement a Center of Excellence ("CoE") covering all aspects of Contractor Oversight.
- Implement risk-based standardized contractor prequalification processes, procedures, and tracking metrics.
- Develop remote inspection capability allowing for oversight of all contractor operations.
- Create standardized contractor performance metrics paired with common contracts, in line with Consumers Energy's Safety Culture.

3. GAS SAFETY MANAGEMENT SYSTEM (GSMS)

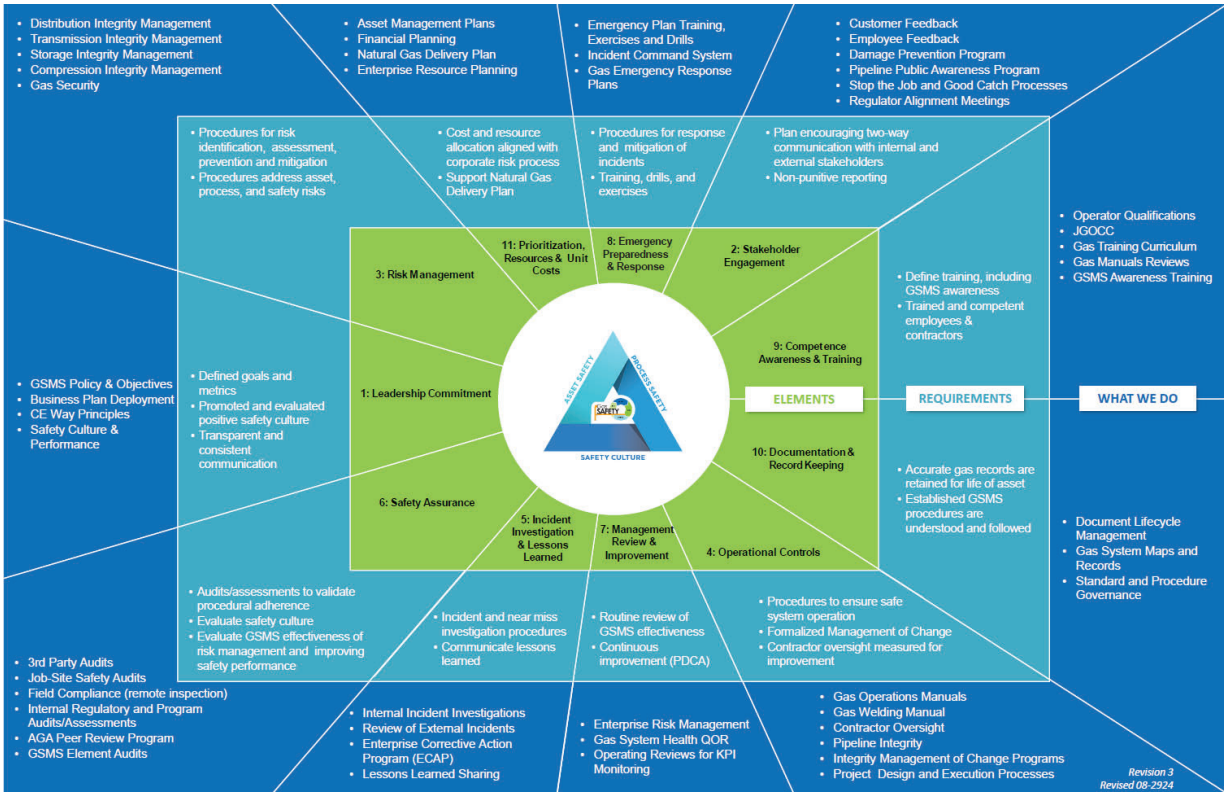
The Company is engaged in continuous improvement of the Gas Safety Management System ("GSMS"), identifying and mitigating risks related to the operation of the gas system.

GSMS is the Company's approach to conforming to the requirements of API RP 1173. The elements and related processes included in the GSMS are referenced in Figure 33.

In support of continuous improvement, the governing policy for the GSMS was expanded in 2024 to encompass additional areas of the utility. The CE leadership-approved policy states "Consumers Energy employees and contractors will comply with regulations, adhere to and continuously improve all Company natural gas, electric, and supply policies and procedures to improve overall system safety and reliability for Michigan and our co-workers."

To support the policy in action, GSMS maintains visibility of key performance indicators to leadership resulting in identification of improvement opportunities that enhance gas asset safety. Improvement opportunities are managed through the enterprise corrective action program developed as a part of GSMS.

Figure 33: Overview of Gas Safety Management System



4. ENTERPRISE CORRECTIVE ACTION PROGRAM ("ECAP")

The ECAP provides an enterprise standard and governance, supported by an auditable, electronic system of record (DevonWay). This enables reporting of potential and identified non-conformance events and issues. This process primarily supports the Incident Investigation, Evaluation & Lessons Learned element outlined in our GSMS program in accordance with API RP 1173.

A dedicated ECAP team, supports an industry benchmarked CAPA process outlined in the ECAP standard as follows:

1. *Issue Identification* – System, Asset and Process Safety issues/findings and/or events.
2. *Evaluation of Issue* – Risk ranking (impact and severity) in the context of Safety, Regulatory Compliance, Financial, Environmental and Reputation.
3. *Detailed Investigation* – Utilizing a systematic methodology to identify root cause(s) so corrective action plans address more than just symptoms, but systemic issues.
4. *Implementation* – Corrective Actions planned, approved, assigned and implemented as designed.
5. *Verification* – Confirmation with objective evidence that the issue has been adequately addressed and risk mitigated/eliminated.
6. *Effectiveness/Sustainability Review* – A periodic assessment post verification that recurrence of original issue is no longer present, and actions once implemented are sustained.

Performing this standard CAPA process prioritizes issues commensurate with the evaluated incoming risk. This process resulted in a year over year decrease in non-compliance violations and enterprise risk on the system.

5. GAS DAMAGE PREVENTION STRATEGY

The Company's vision for Damage Prevention is to **improve compliance with Public Act 174 through reducing and preventing excavation damages to the gas distribution system** in support of employee and public safety.

Damages are caused by home/business owners or excavators digging around Consumers Energy gas distribution assets. The primary causes of damages are due to:

- Inadequate excavation practices (failure to hand dig, failure to maintain marks, improper backfilling).
- Failure to call MISS DIG and working outside of valid ticket window.
- Locating practices not sufficient (mismarked facilities, record errors, system issues).

A series of field programs are deployed to support the 3rd party excavating community with industry best practices including:

- Proactive outreach program – risk-based outreach program to assist the excavating community proactively including coaching and training, locating assistance.
- Repeat damager program – step escalation program targeted to mitigate the highest risk excavators.
- No-call damager program – coaching and enforcement program to mitigate the highest risk excavators not properly using one call processes.

The Company is also planning to engage in discussions with repeat third-party damagers and collaborate with regulatory stakeholders, to continue to improve in this area. Key considerations in the strategy are **focused on behavioral change, including a combination of trust, relationships, and accountability**.

In 2023, a dedicated gas distribution workforce was established to improve timeliness, accuracy, and excavator communications on projects and serves specific Consumers Energy needs leading to improved timeliness compared to historical performance. This will be achieved by having a single utility focus for ticket management.

Another key objective is quality, with **improved staking accuracy performance** compared to recent historical data. **Improved communications with the excavating community** will be enabled by use of enhanced positive response. The Company tracks timeliness and related cause of contractor damages to show the benefits realized from the dedicated model.

In 2024, the Company expanded the dedicated gas distribution workforce to include 30% of total ticket volumes.

In the first quarter of 2025, the Company plans to expand the dedicated workforce to include 100% of total staking ticket volumes.

Plans for the dedicated workforce implementation were accelerated after the analysis of 3rd Quarter 2024 requests for proposal resulted in a dedicated workforce approach being more economical when compared to a shared workforce approach for the remainder of the companies' gas service territory. This is, in addition, to the realized performance improvements in timeliness and staking accuracy.

6. LOST AND UNACCOUNTED FOR GAS

a. Overview of Lost and Unaccounted for Gas

Lost and Unaccounted for ("LAUF") Gas is the difference between the total measured transmission and distribution pipeline system gas volumes received less gas volumes delivered.

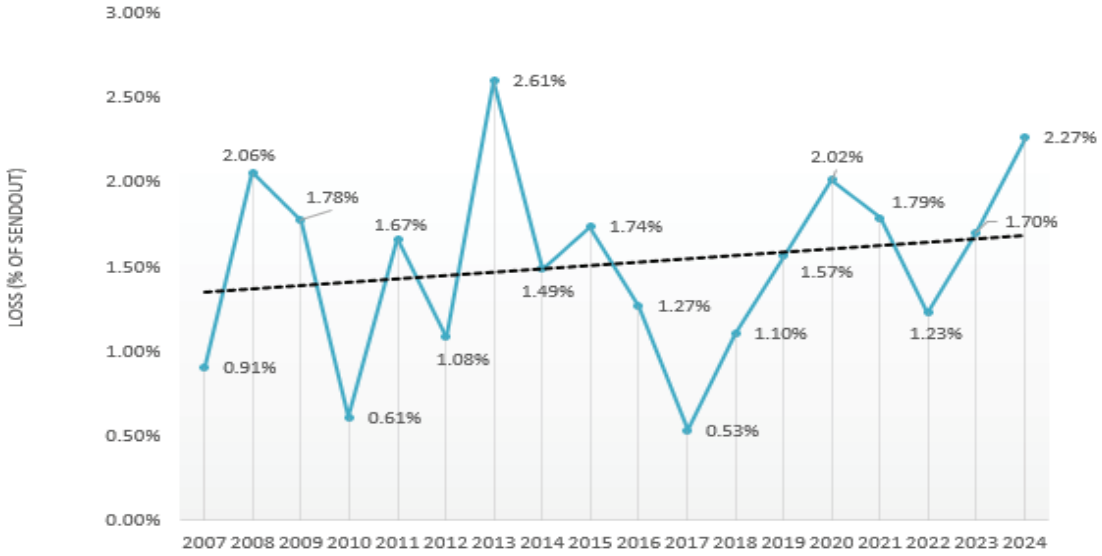
A 'loss' occurs whenever measured receipts are greater than the deliveries of the pipeline system. Conversely, a 'gain' occurs whenever measured deliveries are greater than the measured receipts. Factors that contribute to gas losses and gains are described in section b.

LAUF = (Total Measured Input Volumes - Total Measured Output Volumes)

The Company calculates LAUF annually, based on 12 months ending July 31. This is the percentage used for reporting purposes. There is natural variability in the yearly data due to factors such as weather and load distribution.

As shown in the chart in Figure 34, the overall trend shows an average loss of 1.48%. Through general rate cases the Company recovers LAUF expenses based on a five-year average of line losses, based upon current cost of gas.

Figure 34: LAUF Historical Reporting (volumes for 12 months ending July 2007-2024)



b. **Factors Contributing to Gas Loss**

There are many factors that contribute to gas losses or gains. The most common factors are related to equipment, measurement accuracy, theft, and leaks.

- Equipment issues can be incorrect sizing, condition, and location of meters and meter components.
- Incorrect calibration of meters and/or transmitters, data interface, and communication errors between systems can also cause inaccuracies.
- Other factors are inaccurate estimates of lost gas during venting of gas or when damages to the system occur, and stolen gas.

c. Plan for LAUF Monitoring and Control Improvements

1. Smart Energy and Gas AMR

With the completion of the AMI and Gas AMR projects, the Company will incorporate monthly calendar reads for the calculation of delivered gas to sales customers, reducing the impact of cycle billed reads. This mitigates the unbilled volumes inherent in the lag between meter reads and customer billing.

2. Gas Quality and Measurement Improvement Projects

Pressure, temperature, and gas quality are the contributors to accurate measurement. To increase measurement accuracy for volume, heat content, specific gravity, pressure, and temperature effects, the Company plans to replace 230 orifice meters, which range in age from 50 to 65 years old, using highly accurate ultrasonic meters ("USM") and install 20 additional gas chromatographs across the state over the next 15 years.

3. **Increase Utilization of Flow-Cal Enterprise Gas Automation Software**

   Gas system segmentation within the Flow-Cal system includes installation of boundary meters to enable system segmentation and tracking of LAUF by zones (segments). Further refinement into zones results in improved LAUF tracking and issue identification.

4. **Infrastructure Improvements**

   The age and materials of the distribution system affects LAUF. Natural deteriorations in vintage materials causes corrosion and cracking in piping which results in leaks across the system. Replacement of vintage materials and other aged assets should reduce gas loss over time.

C. Technology – Digital Approach

Digital capabilities optimize compression and storage assets, modernize the distribution and transmission systems, incorporate predictive and condition-based maintenance, transform work management, and ensure physical and cybersecurity of assets. From a digital perspective, Consumers Energy's is focused on:

- Faster delivery with new practices such as adopting agile frameworks.
- A move to cloud solutions where and when appropriate.
- Data as an asset and deployment of larger-scale analytics.
- Deployment of a consistent asset management system/framework.
- Deployment of integrated control systems for system automation.
- Continuous operational improvements through automation.
- A commitment to ensure digital investments do not introduce unnecessary risk to the Company or its customers, and to protect sensitive data and critical infrastructure from cyber threats.
- Evaluating current strategic platforms to ensure they are fully leveraged/optimized, and implementing enhancements as needed to provide new functionality for emergent business and customer value.

  Evaluating new platforms that can further enhance the Company's capabilities. This is in alignment with API RP 1173, "*11.2 – Management shall also periodically evaluate new technology that may enhance pipeline safety.*"

1. LOST AND UNACCOUNTED FOR GAS

Supporting digital capabilities including platforms, tools, processes, and frameworks enable business outcomes. Key capabilities are shown below:

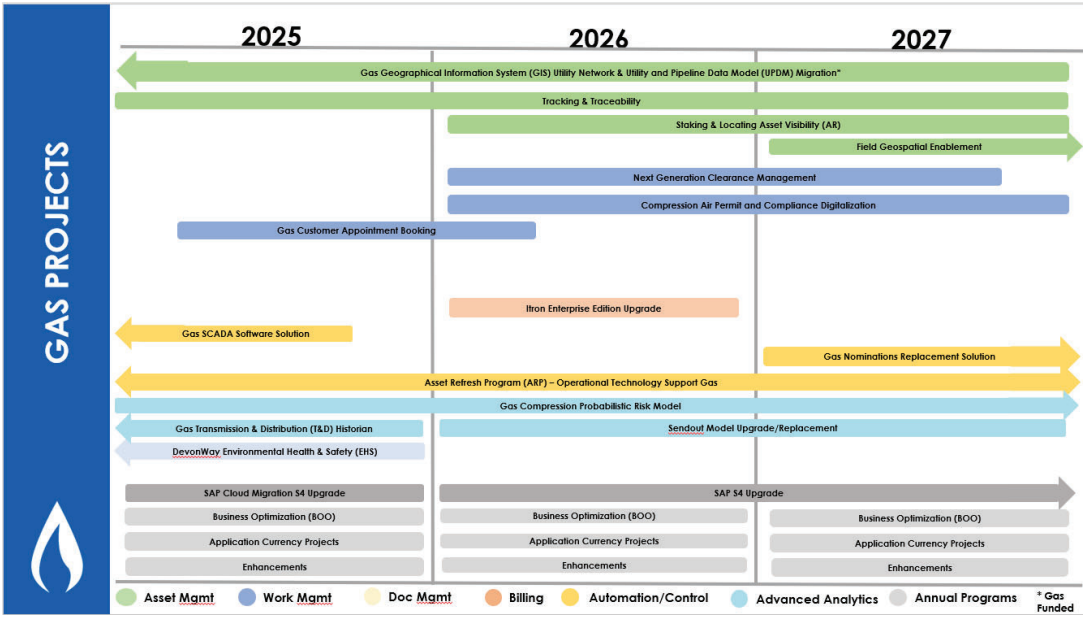
- **Data and analytics** – Accurately manage and collect data, integrate across systems and applications, and create insights to inform business outcomes and decisions.
- **Data management and governance** – Manage data as an asset through data life cycle process (create, update, and delete) for master data management.
- **Data integration** (Application Programming Interface Fabric) – Integrate data across platforms, systems and applications with a reusable framework to increase speed of delivery for new integrations, and avoid costs associated with point-to-point integrations.
- **Work automation with artificial intelligence** – Automate repetitive tasks through software to improve efficiency and productivity. This includes low-code/no-code application platforms that enable employees across the Company to build simple applications to automate their business processes.

- **Cloud platform enablement** – Manage scalable solutions, platforms, and technical infrastructure remotely over the Internet to flex capacity with demands. Consumers Energy is currently using cloud solutions by adopting Software as a Service ("SaaS") and Platform as a Service ("PaaS") offerings. Key platforms include EWN Services Operator Qualifications for tracking and renewals of employee's qualifications, ARCOS solution for employee schedules and callout, ESRI's ArcGIS Online for creation of focused mapping and analysis solutions, ServiceNow, Office 365, and SAP SuccessFactors are examples of SaaS solutions that have been implemented.
- **Cloud technologies** – Integrate data and run advanced analytics at scale using leading machine learning and artificial intelligence frameworks.
- **Electronic content management** – Manage enterprise content/data to enable digital document management for retention, compliance, and privacy.
- **IT Infrastructure and Communications Technology** – This technology is critical to business applications, providing a strong backbone required for supporting 24 x 7 Operations. The technology is key to manage data, voice and multimedia communications through a reliable and redundant network infrastructure with robust frameworks to protect physical and cybersecurity assets. The technology also supports communication for truck connectivity, virtual private networking, mobile phone connections, and field communications. Field communication via 800 MHz radio provides dedicated mission critical connectivity between dispatch and field operations. The Company recently migrated to the Michigan Public Safety Communications System to improve coverage and reduce costs.

2. TECHNOLOGY INVESTMENTS

The Plan includes digital investments in the following areas: asset management, work management, system automation and control, security and privacy, and advanced analytics. An overview of digital projects over the next few years is shown below in Figure 35.

Figure 35: Overview of Consumers Energy Digital Projects



a. **Asset management** investments include the ability to store, manage, and track Company gas assets as part of asset life cycle management and predictive maintenance practices.

- Projects include the transformation of the Enterprise gas GIS system to the new industry standard Utility Pipeline Data Model, and implementation of the Utility Network extension to merge the transmission and distribution into one data model. This will allow:
  - A unified Gas GIS by combining Transmission and Distribution networks into their respective GIS data models: Gas: Wells → Meters.
  - Enhanced Data Quality Control via gas rules managed at the system level.
  - Develop geospatial insight on a more granular asset level, and more accurately define how each part of a utility system is connected.
  - System Tracing (Upstream, Downstream, Pressure Zones, Protective Device, etc.).
  - Enable future benefits such as GIS editing in the field, data capture via GPS/Bar Code scanning, and GIS-enabled design.

  The Utility Network will enable transformational enhancements in the way we operate, making us more efficient, more reliable, and safer.
- In driving to a single source for the geospatial location of Company gas assets, Consumers Energy is migrating gas service records into GIS. Completing this effort will create a single source for distribution asset location, simplify processes, reduce opportunities for inconsistencies in data sources, enhance the ability to interrogate and improve the data, and increase public safety.
- Extending the implementation of ProjectWise for Gas Distribution assets facilitates a management of change process for gas engineering design and gas system configuration changes—increasing public and employee safety and regulatory compliance with complete and accurate records that are easily accessible and searchable.
- Advanced Methane Detection using Picarro technology helps prioritize and plan for the accelerated pace of vintage material remediation, perform risk-based surveying in the compliance leak surveying process, and measure emissions from distribution pipelines.

  The Company currently uses asset-based compliance leak survey to perform compliance leak survey. It is a method whereby individual assets are surveyed based on the compliance due date regardless of where the asset is located within the gas system. Grid-based compliance leak survey is performed in quarter-mile sections. The survey will include all in-scope assets within a quarter-mile section at the same time. The cadence for returning to perform compliance leak survey in that area again is based on the asset makeup within that area. The frequency is determined by the compliance schedule of the asset makeup within that area.

b. SCADA historian secures data required for gas accounting, operational planning, and predictive maintenance. The Company will require live digitized records and performance of all assets to enable predictive calculations and a potential future state of machine learning. The SCADA historian is undergoing a replacement with a modern platform which will **improve administrative applications and will streamline historic data accessibility, visualization and analysis.** The Historian Project supports the broader Gas SCADA Transformation Roadmap discussed in part d. The Historian Project completion is synchronized with the Gas SCADA replacement project completion.

c. Work management and field service management solutions provide electronic capabilities for work forecasting, resource and work planning, work scheduling, dispatch, field execution and closure, tracking performance and work trends, and reacting/responding to emergencies.

- Advanced fleet telematics enhance the visibility of crew and work location, create opportunities to improve crew and work dispatching.
- Modern technology tools are also required for work groups still using paper forms, including the Gas Measurement, Regulation, and Pipeline & Storage and Gas Construction.
- Enabling contractors with an electronic work management system supports improved accuracy and timeliness of work. Fully digitizing the work management experience supports improved customer service by providing real-time work status.
- Improved field mapping and graphics functionality enables better visibility of maps and drawings in the field including the ability for field redlines/edits to ensure records are accurate.
- Advanced planning and scheduling work management features will lead to efficient work assignment to field employees and other resources for improved customer service.

d. **SCADA** is comprised of software and hardware components used to monitor, analyze, and control real-time data from field devices on the gas system. Field data from measuring devices (sensors, valves, meters, etc.) is collected using a Remote Terminal Units ("RTU") and then relayed to Gas Control where software is used to display for operators to analyze and interact with.

- **Gas Control SCADA Transformation Roadmap**

  The Company's system has outgrown the current gas SCADA software solution, Citect implemented in 2000. As the solution ages, increased effort is required to address obsolete application and database software architecture, and enhancements to the system are limited.

  The current gas SCADA tool limits increased system health monitoring and preventative maintenance capabilities due to the inherent complexity. Replacement of the gas SCADA Citect software is planned for completion in 2025. Transitioning to a more advanced gas SCADA software system provides:

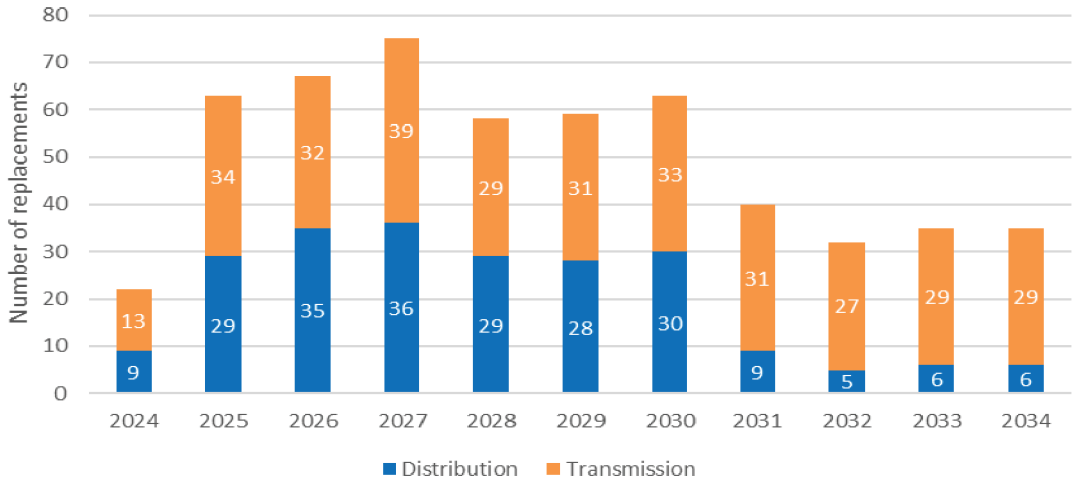
  a. Integration with GIS for system control reliability.
  b. Gas system visibility and transparency.
  c. Deployment of RCVs integrated with the gas SCADA system.
  d. The future ability to control and perform remote shut-off to preserve safety and reliability of the gas system.

- **Remote Terminal Unit (RTU) Solution**

  The current RTU solution, called SixNet, was implemented in 2006. The SixNet hardware and software required to program and operate RTUs are no longer supported by the original equipment manufacturer ("OEM").

  New RTU models support DNP3 protocol offering multi-channel communication and enhanced Cyber Security protections. The plan is to replace the existing SixNet RTU platform with a new platform, shown in Figure 36.

Figure 36: The 10 Year RTU Replacement Plan



e. **Security and privacy** investments secure key Company assets, including physical locations with card access.

   Transitioning from a lock-and-key system at city gates to card access centralizes access control and enhances security. The system is capable of both single-factor authentication (card only) and two-factor authentication (card and code).

   - Currently the Company deploys two-factor authentication in only the most sensitive physical areas (generally North American Electric Reliability Corporation ("NERC")/Critical Infrastructure Protection ("CIP") medium assets). Two-factor authentication is under investigation for gas facilities over time, as security and regulatory requirements mature.
   - Card access management is a single, centralized system and process for the Company. Processes are in place to deactivate badges immediately upon notification of separation from the Company and automatically when not used for specific periods of time.
   - Modernizing and standardizing the gas SCADA network at gas compressor stations and control rooms to mitigate cyber security vulnerabilities, and to allow compliance with API requirements to provide a secure gas system that meets customer needs.
   - Implementation of security infrastructure to enable more visibility and protection of critical infrastructure, including but not limited to, perimeter fencing, security cameras, and two-way audio.

f. **Advanced analytics** investments include data collection, standardization, and analytical model frameworks.

   - Consumers Energy plans to apply advanced statistical and predictive modeling tools and techniques for deriving insights from gas system data. Such projects enable damage prevention predictive analytics and customer-level load profiling and predictive models with propensity ranking for future gas DR programs.

- Integrating operational gas system data to a consolidated data repository will strengthen operational reporting and analytical capabilities. For example, customer value modeling efforts revealed the need to invest in a repeatable capability for rapid system configuration modeling to run scenarios as future supply states and customer demand evolve.

The Company's current maintenance practices vary among assets. For example, compressor units use a mix of usage-based and time-based maintenance for large parts. This means parts are replaced based on throughput or time since last replacement. Select smaller parts use a break-fix approach.

Moving all maintenance plans to *predictive* instead of reactive schedules will help to better allocate resources while maintaining integrity of safety and reliability.

f. **Probabilistic Risk Model**

To manage system risk, the Company uses multiple indexed risk models for asset areas, which are used throughout the gas utility industry. These models have changing risk factor weightings annually that affect project planning and resource requirements.

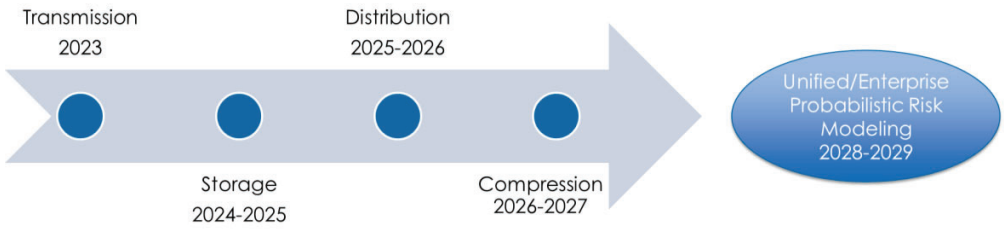
Gas pipeline systems have a complex set of inputs, and their performance is based on a series of possible outcomes controlled by a range of probabilities.

The Company's goal is to implement probabilistic risk models for transmission, compression, distribution and storage by 2030.

The industry is shifting from relative index risk models toward probabilistic risk models. PHMSA defines probabilistic as *a model with inputs that are quantities or probability distributions, with outputs that can be expressed as probability distributions.*

Model logic attempts to adhere to laws of probability. A probabilistic risk model helps better allocate resources by making decisions based on data associated with impact and probability. Figure 37 shows a roadmap for implementing Probabilistic Risk Modeling across the major asset classes between 2023 and 2029.

Figure 37: Probabilistic Risk Model Upgrade Roadmap

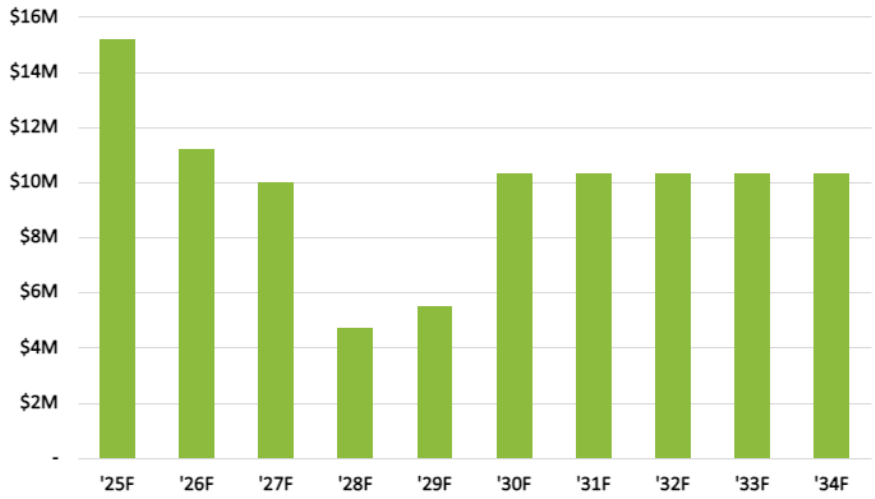


This roadmap will not only account for the entire system but will also result in a Unified Model. The benefits of the unified model are as follows:

- A clear understanding of the existing and projected future performance of assets including reliability and integrity.
- The ability to articulate risk and investments to regulators and stakeholders.
- The capability to make budget decisions based on risk and reliability across the entire system.
- Assurance the investment profile is aligned with the Enterprise risk profile.

Figure 38 shows forecasted capital investments for this digital implementation into the gas system and will support many gas projects and programs.

Figure 38: Digital (IT) Capital Investment Plan



Equally as important as new digital investments in technology as an integral element of the Plan, is the ability to properly maintain technology assets after implementation.

Prudent technology asset management and replacement programs, system monitoring, timely upgrades, and continuous system patching to mitigate cyberthreats are necessary Information Technology ("IT") O&M expenditures required to sustain business operations, and provide the experiences customers expect.

NOTE: More information on Digital, including a corresponding financial summary, is available in the Company's *Digital Three-Year Plan*.

VI. Gas System Decarbonization

Consumers Energy is implementing industry-leading plans to reduce greenhouse gas emissions created by its natural gas operations. This includes modernizing its natural gas system to achieve net zero methane emissions from its operations by 2030.

Consumers Energy leads Michigan's clean energy transformation by looking beyond its own operations to help customers and suppliers reduce their greenhouse gas emissions, especially those generated from natural gas sources.

In 2022, the Company committed to achieve net zero greenhouse gas emissions from the entire natural gas production and delivery system, including customers and suppliers, by 2050. To support this goal, the Company will demonstrate steps required to achieve this goal through investigating customer preference and demonstration of clean fuel technologies. This 2050 net zero goal supports Michigan's MI Healthy Climate Plan to achieve net zero carbon emissions by 2050, including an interim state target of reducing emissions from space heating 17% by 2030.

Additionally, Federal Executive Order ("EO") 14008 of January 27, 2021, commits the United States to a broad action plan addressing climate change. This EO directs federal agencies to prioritize projects that reduce emissions of toxic substances and greenhouse gases from existing and abandoned infrastructure, and to coordinate investments to achieve substantial reductions of methane emissions from the oil and gas sector as quickly as possible. Consumers Energy will remain agile and adjust as needed to accommodate policy as it evolves both on a federal and state level.

The U.S. Environmental protection Agency (EPA) tracks greenhouse gas emissions in three categories:

- **Scope 1**: Direct emissions from sources that are owned or controlled. At our Company, these are emissions produced in the process of generating and supplying energy for customers, such as carbon emissions from burning methane or fugitive methane emissions from our natural gas delivery system. **The Company's goal to reduce Scope 1 emissions is "methane net zero by 2030."**
- **Scope 2**: Indirect emissions associated with the purchase of energy for any end use. These emissions may arise from the energy we purchase and use at our facilities and comprise only a fraction of the emissions linked to our company.
- **Scope 3**: Emissions are from sources not owned or directly controlled but related to our activities. These include all emissions traced to natural gas we purchase and activities by customers and suppliers, primarily from end uses like burning natural gas to heat homes and businesses. **The Company's goal to reduce Scope 3 emissions is "net zero carbon emissions by 2050."**

1. METHANE NET-ZERO GOAL

Consumers Energy recognizes methane as a greenhouse gas emission, and that methane's impact as a greenhouse gas is notably more significant than that of carbon dioxide, with a short-term global warming potential that is approximately 100 times greater.

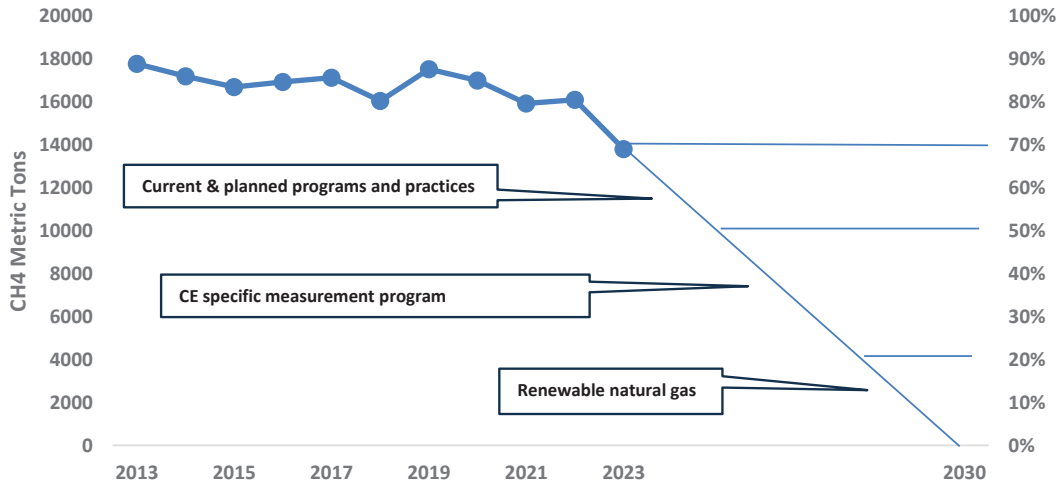
As of 2023, the Company's system emitted 13,811 metric tons of methane. This means that removing methane early in our decarbonization journey has an even greater benefit to the environment. Even over longer time horizons, methane's global warming potential remains 25 times that of carbon dioxide. Since 2012, Consumers Energy has reduced its methane emissions from its natural gas delivery system by approximately 27%.

The methane net-zero plan seeks an 80% reduction of methane emissions by 2030 through the following near-term measures:

- Distribution main leaks: replacing vintage pipe (cast iron and unprotected steel).
- Distribution services leaks: replacing vintage pipe (copper and bare steel).
- Storage: Wellhead component leaks (plug and abandon program).
- Compression blowdown venting procedures: reducing natural gas venting frequency/duration.
- Transmission blowdown procedures: increase temporary compression to reduce venting.

As shown below in Figure 39, procurement of carbon credits potentially through RNG is expected to cover the remaining 20% methane emissions to achieve net zero for the delivery system.

Figure 39: Net Zero Methane Goal: Emission Reduction and Renewable Natural Gas Offset



2. NET ZERO CARBON EMISSIONS GOAL BY 2050

In March 2022, Consumers Energy committed to net zero emissions from sources not owned or directly controlled but related to our activities on or before 2050. These include all emissions traced to natural gas purchases and activities by customers and suppliers, like those associated with burning natural gas to heat homes and businesses.

Reaching 'net zero' will require Consumers Energy to balance many diverse emission reduction opportunities with safe, reliable, and affordable energy delivery.

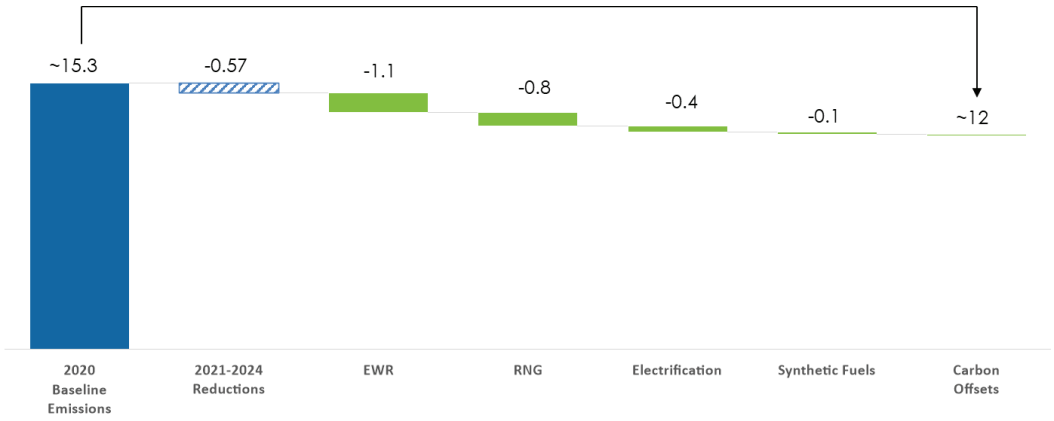
It will also require working partnerships with stakeholders across the state to ensure a decarbonized gas system can continue to meet the needs of customers, communities, and businesses.

Overall, to support Michigan's decarbonization goal and meet carbon neutrality by 2050, Consumers Energy has set an interim goal to work with our customers to help them achieve a 20% reduction in Scope 3 emissions by 2030.

Consumers Energy will actively investigate all clean fuel pathways to meet the needs of customers and assess which technologies best support the energy transition.

The plan to achieve this 20% reduction by 2030 is shown below in Figure 40, which illustrates that EWR, RNG, carbon offsets, and new emerging decarbonization technologies are all necessary pathways.

Figure 40: Scope 3 20% carbon emission reduction by 2030



Customer Programs

Consumers Energy offers customers voluntary options to reduce emissions associated with natural gas use through the Company's MI Clean Air Program[11].

In February 2022, the MI Clean Air Program was approved to provide a voluntary offering for customers to offset the emissions tied to natural gas use via the use of forestry carbon offsets sourced in Michigan. In March 2024, the Company received additional approval to expand the Program to include RNG as a clean fuel alternative for full-service natural gas customers.

- **Carbon Offsets**

  A carbon offset reduces emissions of greenhouse gases made in a separate location. In this way, a reduction in emissions is made in one location to compensate for emissions in a different location, negating the effects of the remaining emission. Accordingly, this Program will provide customers the option to offset the carbon impact of the conventional natural gas used at their location. The Company will supply offsets from in-state forestry projects located in the Upper Peninsula. Limiting the volume of deforestation through this project promotes clean air, preserves wildlife habitats, and clean carbon storage.

- **Renewable Natural Gas (RNG)**

  Consumers Energy received regulatory approval in 2024 to provide RNG to customers on a voluntary basis. As part of approval, the Company will build, own, and operate RNG production facilities to provide customers a clean fuel alternative to natural gas sourced from Michigan.

3. RENEWABLE NATURAL GAS (RNG)

RNG is pipeline quality gas that is low-carbon or carbon-negative, and can be used in existing pipelines and end uses. RNG is created by capturing methane from the decomposition of organic matter through anaerobic digestion. This decomposition can occur in wastes associated with food, animals, landfills, wastewater and forest residues. This methane would otherwise be vented into the atmosphere.

[11] *MI Clean Air Annual Report 2024:* [0688y00000DXDy2AAH (site.com)]

This captured gas is called **biogas** and must be further refined to meet pipeline quality specifications necessary for pipeline injection and customer end use. Once purified to meet pipeline quality standards, the gas is called **RNG** and is chemically identical to fossil natural gas.

- RNG feedstocks including animal waste, landfill, wastewater and food waste are consistently available in Michigan, and can be converted into renewable energy on demand, making it a valuable renewable energy source.
- RNG can also support other environmental goals, including reduced nutrient run-off and improved water quality, organic waste management and diversion, groundwater protection, and displacement of fossil fuels.

RNG Emission Benefits

Benefits are quantified using the industry standard Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation ("GREET") model, resulting in a lifecycle Carbon Intensity ("CI") score. A CI score is the total measure of greenhouse gas emissions associated with producing, distributing, and using a fuel, reflected in grams of Carbon Dioxide equivalents ("CO2e") per megajoule ("MJ") of energy.

After including all RNG process emissions from capturing methane, upgrading it, transporting it, and burning it, the benefit of avoided methane emission to atmosphere is still significantly greater than the total of those lifecycle emissions. The lower the CI score, the more cost effective it is to reduce emissions. This is because with a carbon negative fuel, only a small portion of RNG needs to be blended to achieve carbon neutrality. For this reason, animal manure based RNG is preferred because it has the lowest carbon intensity of any feedstock.

RNG Production

RNG produced from animal waste will supply the Company's MI Clean Air Program, which will deliver approximately 175,000 tons of carbon dioxide equivalents abatement potential annually to voluntary customers across four production facilities in Michigan.

RNG is scheduled for commercial operation in 2025. In support of Public Acts 53 and 166, which require the Michigan Public Service Commission (MPSC) to develop a low carbon energy infrastructure enhancement and development grant program for the purposes of planning, developing, designing, acquiring, or constructing low carbon energy facilities, two (2) grants were awarded to Consumers Energy for RNG projects at Swisslane and TDI Farms in 2023.

Consumers Energy seeks opportunities with farms to help bring clean fuel to the State of Michigan. Any farm can potentially contribute to Consumers' natural gas supply as Renewable Natural Gas. RNG is an opportunity to reduce emissions and improve the environment in Michigan, while supporting local farms.

4. ENERGY WASTE REDUCTION

Since 2009, Consumers Energy implemented a diverse and balanced portfolio of EWR programs achieving significant energy savings for all major sectors and customer classes, including small businesses and low-income customers.

Energy Waste Reduction (i.e., Energy Efficiency) reduces energy waste, lowers bills and reduces emissions. See below in *Energy Waste Reduction* for discussion.

5. EMERGING TECHNOLOGIES

Potential pathways to meeting net zero emissions by 2050 include using hydrogen to produce energy, capturing and sequestering carbon emissions from natural gas combustion, and using synthetic natural gas and electric heat pump systems to heat homes and businesses.

- **Hydrogen**

  Hydrogen has the greatest energy-to-weight ratio of any fuel due to its lack of carbon-based elements. Additionally, hydrogen is an ideal fuel when it comes to emissions as it contains no carbon or sulfur when combusted. Modeling results show hydrogen is most optimally used as a replacement fuel for high heat end use processes that are difficult to electrify[12].

  Note that hydrogen and natural gas are *not* completely interchangeable as a usable fuel at existing pressures and flow rates. However, given advantages tied to dispatch, storage, and carbon neutrality, hydrogen is being assessed by the energy industry to determine its potential as a clean energy pathway for the future natural gas system.

  Hydrogen's zero carbon footprint along with its energy content characteristics make it an important pathway that targets hard to abate high heat processes such as industrial drying, compression, and long-haul transport. The Company's initial focus on Hydrogen is to support customers who currently use Hydrogen and wish to reduce emissions associated with its production.

- **Clean Synthetic Fuels**

  Clean synthetic fuels refer to manufactured natural gas that has no carbon footprint. Manufactured natural gas combines hydrogen and carbon dioxide to form methane under certain conditions. With Michigan businesses recently selected as partners in the Midwest Alliance for Clean Hydrogen (MachH2) hydrogen hub, committed to growing the Midwest regional hydrogen value chain, Consumers Energy is investigating how to best partner with these businesses as an energy provider.

  With synthetic natural gas widely deployed around the world, zero emissions can be achieved by combining green hydrogen via electrolysis with carbon dioxide captured from a Company-owned RNG facility. The result is a zero-carbon form of methane that has no impact to the existing natural gas infrastructure. In 2025, Consumers Energy will investigate the economics and feasibility of this technology in support of the MachH2 hydrogen hub.

- **Electrification – Individual air source heat pumps and Hybrid heating**

  Electrification is the conversion of energy for end uses from natural gas to electricity. The carbon benefit to electrification is the elimination of emissions tied to natural gas combustion. Modeling shows the most cost-effective means of electrifying residential end uses is with hybrid heating. Hybrid heating combines the heat content of natural gas with the efficiency of a heat pump. In this context, heat pumps would be used as much as possible; however, during the coldest winter months, natural gas furnaces would still be used to mitigate winter peak electric load. Consumers Energy is assessing where hybrid heating and heat pump technology can best serve customers.

[12] *Properties of Hydrogen*, 2001. College of the Desert.

- **Electrification – network geothermal systems**

  Geothermal energy is the most efficient form of energy yet high up-front costs remain a barrier to its development. Although ground-sourced heat pumps can be installed on individual homes, Consumers Energy is investigating the concept of 'network geothermal.' A networked geothermal system is a network of ground source heat pumps connected via common ground circuits. Network geothermal systems have two unique attributes. First, they share energy between load centers, where a business that rejects heat for cooling purposes can be used down the street by a home for heating purposes, thereby greatly increasing energy efficiency. Secondly, these systems store heat in the earth during cooling seasons and withdraw that same heat months later during heating seasons just like a natural gas storage field. For these reasons, network geothermal systems drive energy efficiencies upwards of 600%.

  Networked geothermal systems are mature technologies, used for decades on college campuses, and well considered the most energy efficient form of heating and cooling. Two natural gas utilities, *Eversource* and *National Grid*, have network geothermal demonstrations approved through public service commissions today with plans to expand.

  In 2024, the Company received a grant award from the MPSC to study network geothermal across its service territory. The initial objective is understanding how such a system meets the needs and energy preferences of existing natural gas customers. Initial community engagement will occur to educate customers on geothermal benefits, gauge interest in participation and identify anchor users for specific locations. Anchor users are defined as higher load entities that reside near homes and other businesses.

- **Carbon Capture**

  Michigan is unique in that its geology provides large scale potential for underground carbon sequestration. Although not well understood at this time, carbon capture, sequestration and storage remain a key technology to achieve a net zero emissions future.

VII. Energy Waste Reduction (EWR)

Natural Gas EWR programs play a role in decarbonizing the gas system; reducing the amount of energy consumed; and reduces Scope 3 methane emissions.

Additionally, EWR Programs contribute to the Company's Clean Energy Plan goals to end coal use for electricity generation by 2025, reduce carbon emissions by more than 63 million tons, and meet customer needs with 90% clean energy resources (including renewable energy and EWR) by 2040.

Consumers Energy filed its 2024-2025 EWR Plan Filing in August of 2023, case number U-21321[13] and it was settled on February 8, 2024. The portfolio of EWR programs achieves 1% natural gas savings annually, which will cumulate to approximately 14.8 Bcf by 2026 and 26.5 Bcf by 2030

Consumers Energy built the EWR portfolio by selecting program measures (equipment), customer participation, and customer incentives to cost effectively achieve legislative and Consumers Energy clean energy goals. Taken together, the portfolio of EWR programs outlined in this Plan continue Consumers Energy's history of offering a diverse portfolio of cost-effective, flexible, and inclusive program

[13] The February 8, 2024 Case No. U21321 Order Approving Settlement, available on the MPSC website: 0688y00000BulxcAAB (site.com), authorizes gas EWR program investment of $95.5 million in 2024 and $95.1 million in 2025 to achieve 1% of sales gas targets each year.

choices, incentive options, and educational opportunities for every customer class. Consumers Energy's program offerings are summarized in Table 6.

Table 6: 2024–2025 Program Summary

Program Name	Markets Served	Program Offerings
Residential EWR Portfolio		
Appliance Recycling	All residential electric customers	• Incentive and environmentally responsible, free pick up of older, inefficient refrigerators, freezers, and small appliances.
Assessments and Behavioral	All residential customers	• Walk-through or virtual home inspection, installation of free energy-saving measures, and customized post-assessment report with energy-saving tips and recommendations tailored to customer's fuel type (dual fuel, natural gas–only, or electric-only). • Personalized household reports, sent by mail and/or email, with individual energy usage tips and program recommendations.
Home Solutions	Residential customers in single-family homes	• Distributor and point of purchase rebates for the purchase and installation of high-efficiency heating, cooling, insulation, windows, and hot water equipment. • Web-based Find-a-Contractor tool.
Income-Qualified	Residential low-income customers in single-family homes	• Free walk-through or virtual home inspection/assessment with equipment installation. • Home weatherization funding assistance. • Collaboration with community partners to provide maximum and coordinated benefit to income-qualified customers.
Income-Qualified Multifamily	Residential low-income customers in multifamily housing	• Direct, no-cost installation of energy-saving devices in individual tenant units and common areas. • Educational materials explaining the program's energy and money saving benefits. • Prescriptive and custom incentives (offered at a higher rate than those in the Market-Rate Multifamily program) for property owners to install energy-saving equipment in individual units and common areas.
New Home Construction	Residential builders	• Incentives for builders who construct new homes to ENERGY STAR standards or achieve a minimum Home Energy Rating System (HERS) score. • Builder training on high performance building practices and how to promote the value of energy-efficient homes.
Think! Energy	Early elementary to high school students and community groups	• In-class or virtual EWR presentations and educational content for teachers and community groups. • Free energy-saving take-home kit including low-cost energy-efficiency measures and educational content.

Program Name	Markets Served	Program Offerings
Business EWR Portfolio		
Prescriptive	Large business customers	• Prescriptive downstream and midstream rebates ranging from 20% to 40% of the incremental cost of high-efficiency electric and natural gas equipment.
Custom Solutions	Large business customers	• Analysis, performance-based incentives, and technical assistance for large commercial and industrial customers who install high-efficiency equipment or process improvements not covered through the Prescriptive program.
Energy Assessments	Small- and medium-sized business (SMB) customers	• On-site energy assessments with limited direct installation measures and a report on the measures installed, product recommendations, and tips on how to save more energy. • Installation and direct distribution (via mailed kits) of free measures including showerheads, faucet aerators, pre-rinse sprayers, pipe wrap, and programmable and smart thermostats.
Small Business Store	SMB customers	• Self-service, online marketplace that provides instant incentives for the purchase of qualifying energy-efficient products.
SMB Contractor Rebates	SMB customers	• Installation of common lighting and refrigeration measures by participating trade allies.

The table below outlines the Company's approved 2024-2025 EWR Plan natural gas savings targets.

Table 7: Natural Gas Investments and Savings Compared to Targets

	2023 Actual	2024	2025
Planned Investment, Natural Gas Programs	$99,111,306	$95,487,640	$95,066,407
Annual Natural Gas Savings, Statutory Target (Mcf)	2,171,018	2,515,998	2,506,105
Annual Natural Gas Savings, Statutory Target	0.75%	0.875%	0.875%
Annual Natural Gas Savings, Planned (Mcf)	3,752,780	2,934,071	2,944,466
Annual Natural Gas Savings, Planned (%)	1.3%	1.0%	1.0%

VII. Financial Summary

A. Benefits of the Integrated System Plan

A significant benefit of this Plan is allocating capital using a holistic view of the entire gas system to prioritize projects between asset classes. The four objectives of the Plan (i.e., safe, reliable, affordable, and clean) are used to guide and prioritize future investment decisions. The Company allocates capital based on the most necessary needs and in accordance with these objectives, enabling success in the 10-year outcomes.

B. Financial Profile

The Integrated System Plan informs funding decisions about capital projects. Forecasting work over a rolling 10-year period helps communicate investment in various portfolios over a longer time, while providing the agility necessary to modify plans based on potential internal and external changes over time.

Overall, the total future capital spend shows approximately $12 billion from 2025 to 2034, at an annual capital investment spend of approximately $1.2 billion per year. This level of capital investment is consistent with recent past years with new potential investments for digital technologies, RNG, and other possible decarbonization technologies to evolve the system in the future. The capital forecast helps achieve the safe, reliable, and clean objectives by enabling predictable and affordable customer bills.

Figure 41: 2025 – 2034 Capital Plan

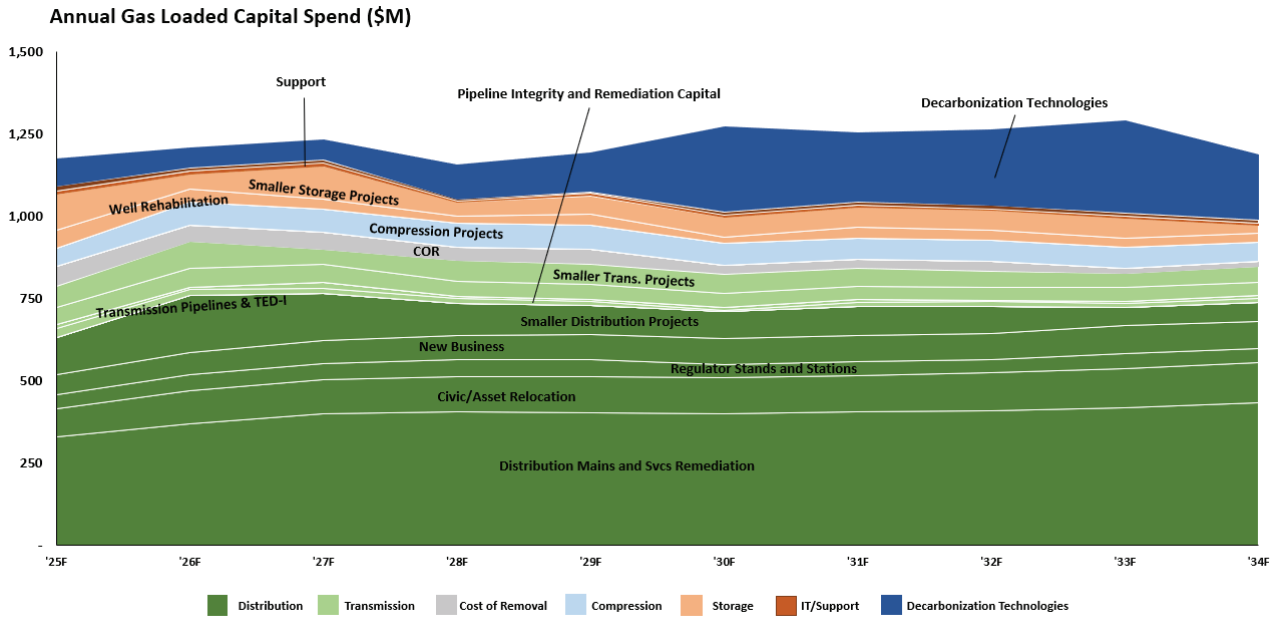
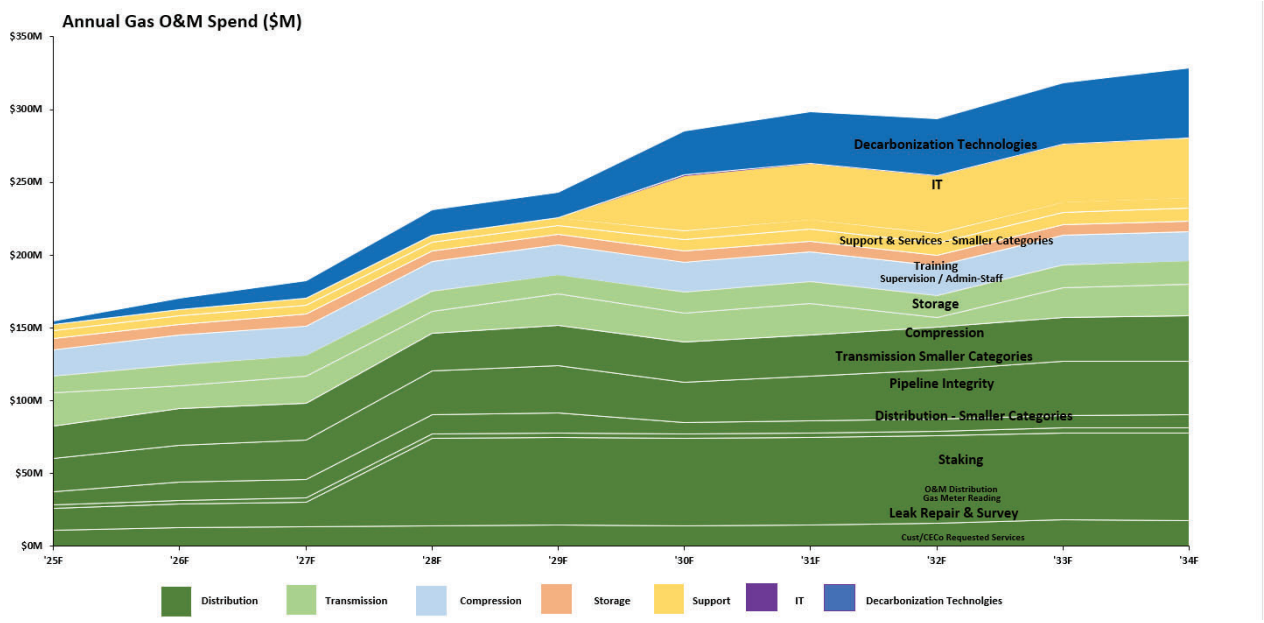


Figure 42 shows that this capital investment will also result in an increase of O&M cost over the next five years. Additionally, the Company anticipates requirements to comply with the Pipeline and Hazardous Materials Safety Administration (PHMSA) proposed Leak Detection and Repair (LDAR) rule to result in an increase in O&M cost beginning in 2028 and beyond.

It is expected that capital investments in the distribution asset class will support the cost of leak repair and survey but will increase due to the continued aging of the system and anticipated enhanced regulatory requirements from the LDAR Rule.

- Given the criticality of maintaining and securing technology assets after implementation, if a gap exists in the IT or other O&M available, the Company will prioritize operational support of its current technology assets over investing in new capabilities.
- The Company's IT O&M projections are calculated based on a comprehensive analysis of known and forecasted expenditures providing accurate and reasonable projections of future year IT O&M requirements.

Figure 42: 2025 – 2034 O&M Plan



VIII. Closing

Consumers Energy has developed this 10-year Plan for the gas delivery system to ensure Michigan has a safe, reliable, affordable, and clean natural gas supply. This Plan highlights commitments to:

- Enhance **safety** by prioritizing and lowering system risk throughout the gas delivery system.
- Deliver **reliable** supply to customers with prudent contingency planning.
- Provide **affordability** to customers through stable, competitive, and predictable energy value.
- Create a **cleaner** gas delivery system that reduces greenhouse gas emissions.

The Plan reflects a thorough analysis of the system, the natural gas commodity market, trends, and practices across the industry, and regulatory and customer trends.

Consumers Energy routinely reviews the validity of the inputs and assumptions that led to the updating of this Plan, and will adjust in the future as appropriate, and continue to share the Company's vision with stakeholders across Michigan.

Appendix A – Industry Standards

As a regulated gas utility company, Consumers Energy must adhere to many different State and Federal Pipeline Safety regulatory requirements. The following is a high-level, not fully inclusive, list of requirements and industry standards or practices as an example:

Code of Federal Regulations

- 49 CFR Part 191 - Transportation of Natural and other Gas by Pipeline; Reports
- 49 CFR Part 192 - Transportation of Natural and other Gas by Pipeline; Minimum Federal Safety Standards
- 49 CFR Part 199 - Drug & Alcohol Testing

Michigan Gas Safety Standards

Michigan Technical Standards for Gas Service

American Petroleum Institute

- Standard 1164 – *Pipeline Control Systems Cybersecurity*
- Recommended Practice 1171 - *Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs*
- Recommended Practice 1173 – *Pipeline Safety Management Systems*

Appendix B – System Figures & Facts

Miles transmission pipeline:	2,342
• Miles of mainline pipelines:	1,560
• Miles of pipeline within compression stations:	22
• Miles of storage pipes:	244
• Miles of TOD:	516
Miles distribution pipeline:	28,368
Number storage fields:	15
Number compressor stations:	8
Number customers:	Approximately 1.8 Million
Number storage wells:	808
Gas storage working gas capacity:	154 Bcf

Appendix C – Decarbonization Modeling

In 2021, Consumers Energy worked with industry leading consultants to better understand the most affordable and resilient state-wide economy decarbonization plan that achieves net zero carbon emissions by 2050.

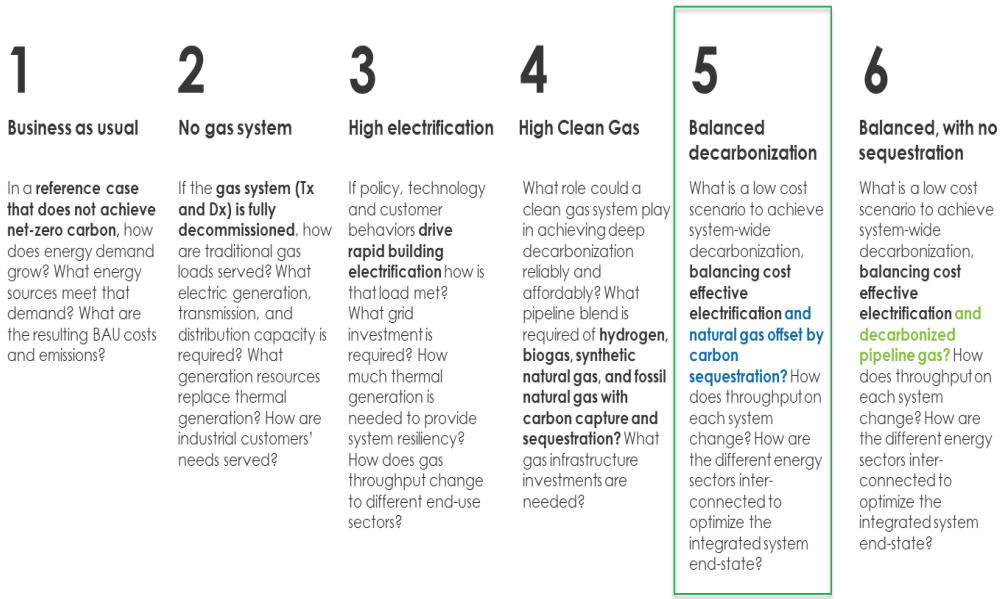
This analysis incorporates both the Company's electric and gas utilities with an 'energy agnostic' approach. It was determined that limiting the scope of analysis to the Consumers Energy service territory would improperly exclude constraining factors like electric vehicle demand on the grid and would not take advantage of geographic and logistical efficiencies throughout the State.

The modeling analysis used regional attributes to understand the most cost-effective energy supply to meet the energy demand of the State, including full electrification of the passenger vehicle sector, while simultaneously achieving net zero emissions by 2050.

The analysis was completed for six different scenarios, shown below in Figure 43. Important assumptions are noted here across three specific scenarios.

- **The business-as-usual scenario is used as a reference point** and assumes no progress in energy decarbonization.
- The **no gas system scenario was assessed to understand the cost of meeting energy demand** in the absence of the gas system, meaning all current uses of gas, including industrial processes and electric generation would require alternative energy supplies like hydrogen or electrification. This scenario also demonstrates the value the current gas system provides to the state's overall decarbonization costs.
- **The high electrification scenario assumes all end uses are electrified except for natural gas electric generators,** meaning the compression and transmission system would remain, while most gas distribution pipelines would be retired.

Figure 43: Decarbonization Scenarios



The key conclusion from modeling was that a **balanced combination of multiple technologies is the most cost-effective means of achieving economy-wide decarbonization by 2050**. The diversity in a balanced combination of multiple technologies not only increases resiliency, but also increases optionality across the system, lowering risk of not achieving carbon neutrality.

In all scenarios, electric load increases due primarily to electric vehicle deployment and some space heating electrification. As coal plants are retired, gas generation with carbon capture grows to meet increasing load.

Renewables are an increasingly important part of Michigan's energy supply, but controllable energy, like long duration energy storage is needed for maintaining a reliable energy supply.

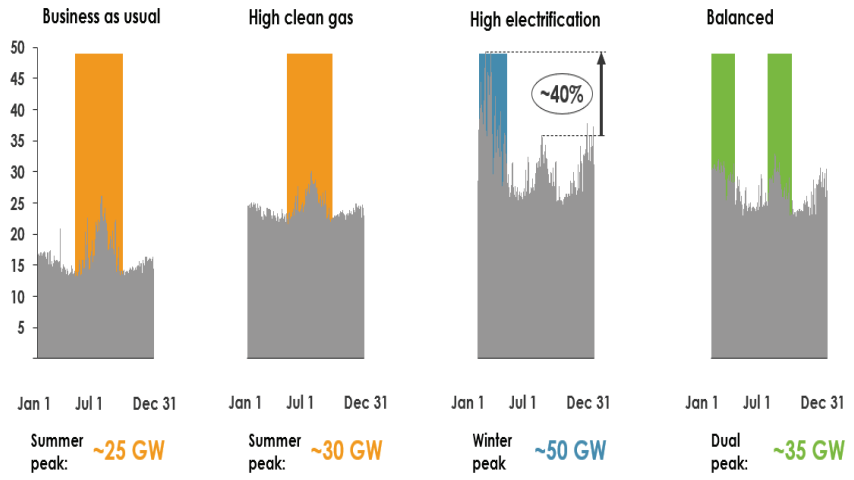
Other important conclusions show:

- The gas distribution system enables cost effective, reliable home heating in Michigan winters.
- The gas transmission system is needed to supply natural gas to electric generators.
- Carbon sequestration is needed to cost effectively achieve durable decarbonization, specifically to support electric generation, synthetic gas and hydrogen production.
- Clean fuels such as RNG and hydrogen provide system resiliency, diversification, and energy for hard to electrify end uses.
- Electrification potential was constrained by costs associated with additional transmission and generation infrastructure necessary to meet winter peaking electric demand.

As shown below in Figure 44, analysis indicates that in a highly electrified decarbonized future scenario, building electrification can drive winter peaks as high as 40% higher than summer peaks. In this scenario, the most economic form of clean electric base load generation to support building electrification would come from natural gas generators fitted with carbon capture.

Hybridized electric + gas space heating, as represented within the 'balanced scenario' can mitigate a peak shift to winter, reducing the need for investment in electric generation and transmission by ~$20-$25B compared to a high electrification scenario.

Figure 44: Potential Electric Peak Load Impacts by Scenario



Additionally, ~20% less electric generation capacity is required in the 'balanced scenario' than in a high electrification scenario, which helps mitigate cost increases.

In each decarbonization scenario, there is a societal cost impact to Michigan with a 'balanced scenario' the lowest societal cost pathway to meet carbon neutrality by 2050. Total energy system costs include all costs associated with energy in Michigan, including feedstock and commodities; electricity generation, storage, and fuel production technologies; energy delivery infrastructure; carbon capture and sequestration; demand-side technologies (e.g., appliances and vehicles, EE investments, etc.).

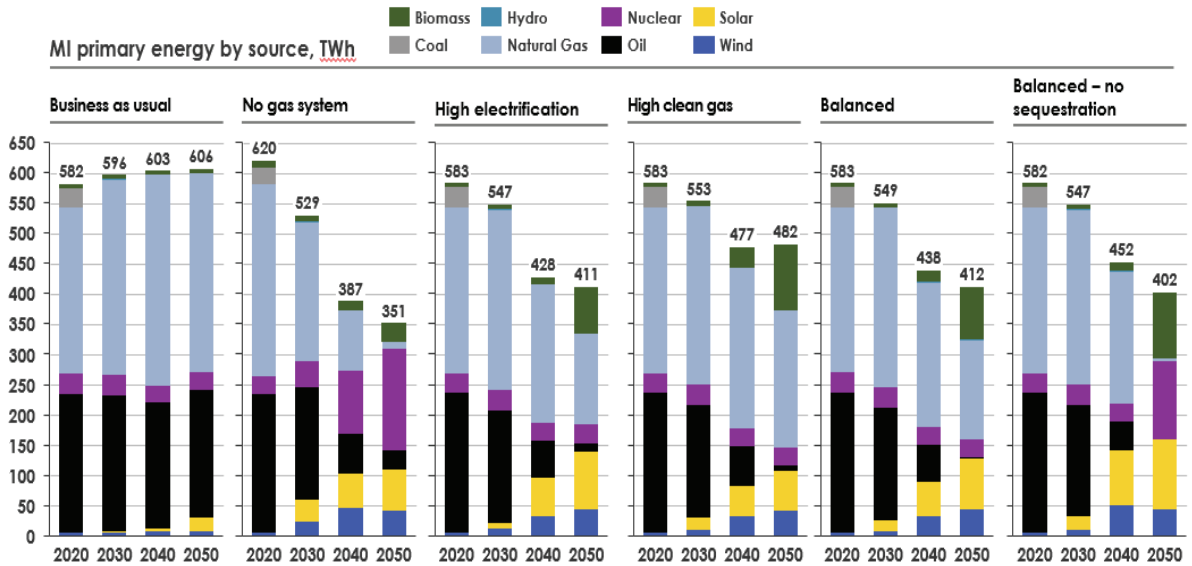
RNG ("biogas") is seen as a foundational technology that best prepares the Company for any likely decarbonized future scenario including high electrification, high clean gas, and a balanced approach. This is because RNG is cost effective in reducing carbon, mature technology, and requires no incremental investment in the existing infrastructure.

RNG resources are available today and require no modification to the existing infrastructure, making it more cost-effective than other approaches. For this reason, the Company offers RNG as a voluntary product to customers providing the State with progress towards our shared environmental goals over time.

In all likely scenarios (high electrification, high clean gas, balanced), modeling shows natural gas generation as the least-cost, carbon neutral energy supply able to meet demand. In the absence of a gas system or carbon-neutral natural gas generation, new nuclear generation would be necessary to support demand by 2050 as shown in Figure 45.

NOTE: This analysis is Michigan-wide and does not necessarily reflect the Company's expected energy supply.

Figure 45: Potential Primary Energy Sources by Decarbonization Scenario



Appendix D – Talent Pipeline

The following initiatives are important steps to attract, retain, and grow the talent within the Company:

1. Career Awareness Activities

- **Michigan Career Quests:** There are 10 MI Career Quest events held throughout the state each year. These day-long events provide hands-on career exploration for high school students.
- **Careers in Energy Week:** Each year the third week of October is declared to be *Careers in Energy Week* by the Governor. The Company makes a concerted effort to promote skilled trades, engineering, renewables, and IT career fields within energy via a series of tours, events, school career fairs, social media contests and campaigns, and public relations activities.
- **Talent Ambassadors (Formerly Education Champions):** Nearly 450 employees raise their hand each year to support local school district career fairs, mock interviews, and to speak with classes about careers in energy, their personal experience and career pathway.
- **Summer Youth Energy Academies:** The Company expanded in 2022 to add Pontiac and Flint to the two summer youth employment programs started in 2021 in Jackson and Grand Rapids. This 6-week academy provides participants with exposure to energy careers while gaining pre-employment essential skills. Intentional efforts to build networks with diverse partners and communities resulted in over 50% of students from historically underrepresented populations.
- **Elementary School Energy Safety and Careers Presentations**: Beginning in 2022, the Company offers hands-on, one-hour presentations for 4th and 5th graders in partnership with the union, UWUA, representing our frontline gas and electric workforce. We have identified the top 10 most diverse school districts in our service territory as the highest priority to deploy these important workshops. In 2022, we reached 1,500 students across 21 schools.
- **Detroit Area Pre-College Engineering Program (DAPCEP)** is a Detroit area pre-college engineering program designed to increase the number of historically underrepresented students pursuing STEM Careers.
- **Project SEARCH** focuses on high school students with cognitive disabilities. The program provides work experience and mentoring to the students while they complete their senior year at our headquarters in Jackson. Consumers Energy was honored, along with six other Michigan Project SEARCH sites, with the employment outcome awards for the 2021-2022 year. The graduating class resulted in 83% of students obtaining employment in the community after their experience. Since its inception, 44 students have participated and graduated from Consumers Energy's program and our company is welcoming 10 new interns for the 2023-2024 school year.
- **Inside Track Webinars** This new popular webinar is focused on promoting energy careers to diverse job seekers. Held three times in 2022, over 1,000 people joined in the one-hour session to learn about our career pathways, school partners, application processes, decoding our job postings, and increasing their employability at Consumers Energy.

2. Training and Education

- **Veteran's Gas Bootcamp:** In partnership with UWUA trade school, Power for America (P4A), the Utility Military Assistance Program: Michigan Gas Boot Camp (UMAP-MI) openly recruits current Michigan National Guard members, Reservists and Honorably Discharged military veterans. The program is designed to provide the requisite skills and knowledge an individual will need for a successful career within the gas utility sector. To date, Consumers Energy has employed 201 Veterans because of the Gas Bootcamp.
- **Energy Industry Fundamentals:** Through the Michigan Energy Workforce Development Consortium, we partner with Career Technical Education centers and high schools (Hartland, Boyne City, Oakland South and Oakland North, Holt, Jackson Public, Jackson Northwest, Western High school) to deliver the national certification course, *Energy Industry Fundamentals*. This course is also offered as a part of college energy programs at Lansing Community College, Jackson College, MIAT, and Henry Ford Community College. Each year more than 250 students enroll in the course statewide.
- **Jackson College Energy Systems Program**: As the college located in our Headquarters' hometown of Jackson, Consumers Energy partners with Jackson College to provide education for a multitude of job roles including gas delivery technicians, planners, and schedulers. Their two- and four-year degree programs in Energy Systems were developed in partnership with the Company and are continually updated to meet our needs.

3. Resources

- **Michigan Energy Workforce Development Consortium:** The Company works with other utilities and provides leadership for MEWDC. This organization is made up of more than 50 partners from education, government, workforce development, and community-based agencies to strategize, plan, and execute activities that increase available diverse qualified workforce.
- **State Apprenticeship Expansion (SAE) Grant Funding:** Most recently MEWDC was awarded a $1.1 million grant ($134k coming to CE) to recruit and train more women, racial or ethnic minorities, and veterans into skilled trade positions.
- **Going Pro Grant:** In addition, the Company receives between $400-500k per year in grant funding to support technical training for our operations, maintenance, and construction workforce through the State Going Pro grant program—ensuring that our new apprentices have access to high quality state of the art training.

4. Diversity, Equity, and Inclusion in the Talent Pipeline

- **Intern Recruiting:** Annually engages in over 50 on-campus recruiting and networking events connecting students to various internal business departments. Partner with various internal Intern Councils to identify workforce needs, schedule recruiting activities, screen, and select company interns. In an average year, the Company vets over 5,000 qualified intern candidates to fill roughly 100-150 positions.
- **Targeted Campus Organizations:** In support of the campus recruitment, the Company will deliberately partner with diverse student organizations in effort to ensure maximum exposure of our intern and career opportunities. Some of the most prominent student organization partners include: Society of Women's Engineers (SWE); National Society of Black Engineers (NSBE); Society of Asian Scientist and Engineers (SASE); and Society of Hispanic Professional Engineers (SHPE).
- **Intern Experience:** During the summer internships, the Company leads several engagement opportunities with the interns to foster a positive experience. Annually, Consumers Energy hosts an intern luncheon experience designed to develop a deeper understanding of our business and build affinity.

- **Professional Organizations:** In support of the core business needs and benchmarking studies, the Company continuously seek partnerships to improve our employee diversity. The goal is to infuse high quality diverse applicants into all our external job postings. These deliberate efforts include a paid partnership with Professional Diversity Network (PDN) to participate in six diverse organization career fairs in 2021 and post all of vacancies on over 30 partner network careers sites reaching over 500,000 diverse jobseekers.
- **Corporate Giving Partnership:** Collaboration with Corporate Giving gives the Outreach Team the ability to connect with recipient organizations to support our workforce needs. These partnerships provide unique opportunities to meet, mentor, and support student bodies that traditionally have a high attrition rate of female and minority students.
- **National Women in Construction (NAWIC) Relationship:** Over the past five years, the Company has maintained a strong working relationship with NAWIC to help promote our opportunities to their membership. Over the past two years, Consumers Energy has shared every external gas construction vacancy posting with NAWIC.
- **Targeted Career Fairs:** Annually, the Company supports more than two dozen career fair events focused on racial/ethnic minorities, females, veterans, and individuals with disabilities.
- **Virtual Engagement:** In 2019, the Company began using virtual career fair platforms to provide more opportunities to reach targeted audiences. This augmentation plan allowed the Company to seamlessly transition to full remote career fair and networking with targeted jobseekers in our current remote environment.
- **Career Bootcamps for Hiring Success:** The Company is creating a pipeline to become an employer of choice for underrepresented communities in high demand occupations. These bootcamps are designed to springboard participants to a successful career. In partnership with trade schools and the Utility Military Assistance Program, our Michigan Gas Boot Camp (UMAP-MI) openly recruits current Michigan National Guard members, Reservists and Honorably Discharged military veterans. The program is designed to provide the requisite skills and knowledge an individual will need for a successful career within the gas utility sector. Successful completers are employed with Consumers Energy as entry-level Gas Lines Construction Laborers.

Appendix E – DE&I Movement Stands

Embedding DE&I focuses on educating our coworkers and highlighting opportunities where coworkers can contribute to creating an inclusive environment.

- **DE&I Awareness Training:** In 2021, the Company launched a from-the-top learning model for our employees for DE&I awareness training. In 2022, 100% of all coworkers were committed to completing DE&I awareness training.
- **Business Employee Resource Groups (BERG)***:* The Company has 2,000+ coworkers, more than 20% of our workforce, engaged in our Business Employee Resource Groups where each embrace differences to improve working relationships and deliver better results for customers, communities, and coworkers. All seven BERGs are employee-led, raising new initiatives that will lead to a greater sense of belonging for all.
- **DE&I Champion Program:** A program made up of union employees and exempt, their mission: Create safe spaces and assist the workforce in embedding DEI into everything we do, at all levels, by promoting an inclusive environment and restorative approach through training, coaching and supporting the workforce one on one, in teams and through inclusive leadership. The program works to advance belonging by leading grassroots communication efforts and action-oriented opportunities for involvement, identifying, and addressing gaps through problem-solving, and providing continuous DE&I learning opportunities.
- **Well-Being Consultants:** "Well-Being Consultants," lead well-being initiatives throughout the Company by identifying and addressing needs of our co-workers and provide continuous opportunities to engage in well-being efforts throughout the organization and beyond (retirees and spouses).

Our Talent Stand: We expect every future and current employee to have equitable opportunity to succeed.

Consumers Energy is building a world-class, inclusive workforce to better reflect our community.

- **100% Diverse Hiring Committees and Candidate Slates**: The Company expects every future and current co-worker to have an equitable opportunity to succeed. The practices include 100% diverse hiring committees and candidate slates for every position posted. Further, the hiring training includes the hiring best practices for our managers, including strategies to mitigate unconscious bias.
- **Summer Youth Energy Academies:** Within the communities where the Company's employees live and work, there are 450+ Talent Ambassadors inspiring K-12 students to become future coworkers—thus building the Talent Pipeline in the communities we serve for future generations. The 6-week Summer Youth Academy provides participants exposure to energy careers while gaining pre-employment essential skills.

Our Supplier Diversity Stand: A vibrant and diverse supplier network increases competition, strengthens innovation, and ultimately benefits customer affordability.

The Company is maturing in diverse supplier programs by building a framework that enables high quality, long-term success, knowing that supplier diversity contributes to operational excellence.

- **Expanding our reach:** The Company connects, supports and develops minority, women, LGBTQ, disability, and veteran-owned suppliers. Diverse suppliers are encouraged to create a business profile on our "Become a Supplier" website. The program will continue to expand across a diverse supplier network and strengthen supplier relationships.

Our Philanthropy Stand: Consumers Energy creates equitable, sustainable change to support social justice initiatives throughout Michigan and the communities served.

The Company has given back to Michigan for more than 135 years, supporting communities through the Consumers Energy Foundation since 1990. The Foundation supports organizations working to advance racial and ethnic justice and striving to further equity for women, veterans, the LGBTQIA+ community, people with mental and physical disabilities, and people living below the Asset Limited, Income Constrained, Employed (ALICE) threshold.

- **Signature Awards:** Each year, the Consumers Energy Foundation makes signature grant allocations of $500,000 each (totaling $1.5 million) to two or more Michigan nonprofit organizations striving to make a positive impact aligned with the corresponding priority area.
- **Supporting DE&I in Local Communities:** In 2022, the Foundation launched an initiative to award $100,000 to five community foundations actively engaged in DE&I efforts in their local communities. Each community foundation received $20,000 to support this important work. Based on the success of this program, the Foundation doubled its investment in 2023 by awarding $200,000 to ten community foundations across the State.
- **BERG Grant Program**: Each year, the Foundation allocates $10,000 in grant funding to each Business Employee Resource Group (BERG).

Appendix F – MAOP Distribution Program & Project List

Line Segment	Estimated Capital Cost	Length (miles)	Expected Pipe Size	Construction Complete Year
Completed Projects				
Line 1009 Huron Park to I94	3,183,351	0.5	12"	2024
Projected Projects				
Line 1020 Greenfield Rd	258,395	0.038	12"	2024
Line 1002f Macomb ITC Corridor	2,991,188	0.07	26"	2025
Line 1009/1009c I94 to Little Mack, 10 Mile to 11 Mile	19,935,392	1.53	12"	2025
Line 1022f Vermontville	378,402	0.038	8"	2025
Line 1087b East & West Segments	10,677,954	0.81	12"	2025
Line 1090n	326,919	0.012	8”	2025
Line 1006 Ph 1 Groebel Dr to Mound Rd	6,295,452	0.31	24"	2026
Line 1009c Ph 3 Little Mack - 10 mile to 9 mile, Macomb	9,643,900	1.3	12"	2026
Line 1026f Mt Hope	10,828,963	0.758	8"	2026
Line 1093 Shattuck Rd	20,900,643	1.76	12”	2026
Line 1080 Dual Main	34,335,275	6.7	12”	2025
Line 1026i MSU PP	3,420,311	0.133	8"	2027
Line 1022	39,867,880	3.5	16”	2026
Line 1006 Ph 2 11 Mile Mound to RR St.	16,448,049	0.75	24"	2027
Line 1009c Ph 4 11 mile - Little Mack to RS22, Macomb	6,926,168	0.5	12"	2027
Line 1041 Lapeer Rd	30,543,990	3.4	12”	2027
Line 1087f S Saginaw Rd	517,836	0.028	N/A	2027
Line 1002	8,020,248	0.33	16"	2028
Line 1002c	177,542,697	8.15	24”	2029
Line 1019w	604,141	0.028	10"	2029
Line 1082 E Kilgore Rd and Portage St	999,769	0.041	12"	2029
Line 1019k Amrhein and Newburgh Rd	341,000	0.028	12"	2030
Line 1019z	31,000,000	4.56	16"	2030
Line 1090l W Caro Rd	1,350,000	0.15	8"	2031
Line 1006 Ph 3 11 Mi/Deq to Dvd Givens	12,000,000	1	16"	2031
Line 1008	26,250,000	2.5	12"	2032
Line 1049d I-475 Crossing on Bristol Rd	298,000	0.028	12"	2033
Line 1091 S Van Dyke-S Outer Dr	7,350,000	0.7	8"/12"	2033
Line 1082 Lovers Lane	4,200,000	0.4	12"	2034
Line 1082f	1,800,000	0.2	8"	2034
Program Level Adjustment	-9,879,144			

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Gas & Common O&M Expense
for the Years 2023, 2024, 2025; and the 12 Months Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-43 (MJF-1)
Page: 1 of 1
Witness: MJFoster
Date: December 2024

Corporate O&M

Line No.	(a) Program Description	(b) Source	(c) 2023 Actual	(d) 2024 Projected	(e) 2025 Projected	(f) 12 Months Ending 10/31/2026
1	Corporate Services Expense	Exhibit A-44 (MJF-2)	$ 27,105	$ 27,972	$ 28,644	$ 26,874
2	Uncollectible Expense	Exhibit A-45 (MJF-3)	$ 17,234	14,908	14,908	15,327
3	Injuries & Damages Expense	Exhibit A-46 (MJF-4)	$ 1,467	2,279	2,279	2,279
4	Manufactured Gas Plant - Direct Project Management Costs	Exhibit A-47 (MJF-5)	$ 949	963	967	930
5	**TOTAL O&M EXPENSES**		**$ 46,755**	**$ 46,123**	**$ 46,798**	**$ 45,411**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Projected Corporate Services O&M Expense
for the Years 2023, 2024, 2025; and the 12 Months Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-44 (MJF-2)
Page: 1 of 1
Witness: MJFoster
Date: December 2024

Line No.	(a) Description	(b) 2023 Labor Actual	(c) 2023 Non-Labor Actual	(d) Total 2023 Actual	(e) 2024 Labor Inflation Projected	(f) 2024 Non-Labor Inflation Projected	(g) Total 2024 Projected	(h) 2025 Labor Inflation Projected	(i) 2025 Non-Labor Inflation Projected	(j) Total 2025 Projected	(k) 12 Mos Ending 10/31/2026 Inflation Projected	(l) 12 Mos Ending 10/31/2026 Inflation Projected	(m) Adjustment	(n) 12 Mos Ending 10/31/2026 Total Projected
1					(b) * inflation	(c) * Inflation	(d) + (e) + (f)	[(b) + (e)] * inflation	[(c) + (f)] * Inflation	(g) + (h) + (i)	[(b) + (e) + (h)] * Inflation	[(c) + (f) + (i)] * Inflation		(j) + (k) + (l) + (m)
2	Sustainability & External Affairs	$ 2,132	$ 398	$ 2,529	$ 68	$ 13	$ 2,610	$ 53	$ 10	$ 2,673	$ 47	$ 9	$ (263)	$ 2,466
3	Legal, Ethics, Regulatory, and Risk	4,175	14,866	$ 19,040	134	476	19,650	103	368	20,121	92	327	(507)	20,033
4	People & Culture and Learning and Development	10,837	2,118	$ 12,955	347	68	13,370	268	52	13,691	239	47	(505)	13,471
5	Finance and Shared Services	8,282	2,127	$ 10,410	265	68	10,743	205	53	11,001	182	47	(1,091)	10,139
6	General Activities	7,428	(3,289)	$ 4,139	238	(105)	4,272	184	(81)	4,374	164	(72)	-	4,465
7	Total	$ 32,854	$ 16,220	$ 49,074	$ 1,051	$ 519	$ 50,644	$ 814	$ 402	$ 51,860	$ 723	$ 357	$ (2,366)	$ 50,574
8	Less: EICP	7,753	-	$ 7,753	248	-	8,002	192	-	8,194	171	-	-	8,364
9	Less: Transfers Out	-	-	$ -	-	-	-	-	-	-	-	-	-	-
10	Total Corporate Service Departments	$ 25,101	$ 16,220	$ 41,320	$ 803	$ 519	$ 42,643	$ 622	$ 402	$ 43,666	$ 553	$ 357	$ (2,366)	$ 42,210
11	Administration & Other-Gas Portion		1,506	$ 1,506		48	1,554		37	1,591	-	33		1,625
12	**Total Corporate Services**	$ 25,101	$ 17,726	$ 42,826	$ 803	$ 567	$ 44,197	$ 622	$ 439	$ 45,257	$ 553	$ 390	$ (2,366)	$ 43,834
	Normalizations													
13	Voluntary Separation Program	(12,582)	-	$ (12,582)	(403)	-	(12,985)	(312)	-	(13,296)	(277)	-	-	(13,573)
14	One-time Legal Consultant Expense		(2,792)	$ (2,792)	-	(89)	(2,881)	-	(69)	(2,950)	-	(61)	-	(3,012)
15	**Total Normalizations**	$ (12,582)	$ (2,792)	$ (15,374)	$ (403)	$ (89)	$ (15,866)	$ (312)	$ (69)	$ (16,246)	$ (277)	$ (61)	$ -	$ (16,585)
	Less Giving and Communications													
16	Corporate Giving Salaries per WP-HLR-12, line 1 and 3	(17)	-	$ (17)	(1)	-	(17)	(0)	-	(17)	(0)	-		(18)
17	Dues, Donations & Lobbying Expenses per WP-HLR-14, line 17	-	(331)	$ (331)	-	(11)	(342)	-	(8)	(350)	-	(7)		(357)
18	**Total Giving and Communications**	$ (17)	$ (331)	$ (348)	$ (1)	$ (11)	$ (359)	$ (0)	$ (8)	$ (367)	$ (0)	$ (7)	$ -	$ (375)
19	**TOTAL ADJ CORPORATE SERVICES EXPENSE**	$ 12,502	$ 14,603	**$ 27,105**	$ 400	$ 467	**$ 27,972**	$ 310	$ 362	**$ 28,644**	$ 275	$ 321	$ (2,366)	**$ 26,874**

		12-Mo Ending 2024	12-Mo Ending 2025	10-Mo Ending 2026
20	Annual inflation rates per Company witness Rayl			
	Annual inflation rates	3.2%	2.4%	2.5%
	Number of months in the period	12	12	10
	Pro-rated inflation rate	3.2%	2.4%	2.1%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Uncollectible Accounts Expense
for the Years 2023, 2024, 2025; and the 12 Months Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-45 (MJF-3)
Page: 1 of 2
Witness: MJFoster
Date: December 2024

Line No.	(a) Description	(b) 2023 Actual	(c) 2024 Projected	(d) 2025 Projected	(e) 12 Months Ending 10/31/2026
1	Uncollectible Accounts Expense	$ 17,234	$ 14,908 [1]	$ 14,908 [2]	**$ 15,327** [3]

[1] 2024 projected amount based U-21490 GRC rebuttal position
[2] 2025 projected amount based U-21490 GRC rebuttal position
[3] Exhibit A-45 (MJF-3) Page 2, row 7, column (g) (3-Year Average BDLR 2021-23)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Uncollectible Accounts Expense
for the 12 Months Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-45 (MJF-3)
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Line No.	(a) Year	(b) Gross Write-Offs	(c) Less Recoveries	(d) Net Write-Offs (Col. (b)-Col. (c))	(e) Less Non-Energy Write-Offs	(f) Net Energy Write-Offs (Col. (d)-Col. (e))	(g) MPSC P-522 Pg. 300 Tot. Gas Svc Rev.	(h) BDLR (Col. (d)/Col. (e))
1	2021	$ 14,593	$ 3,365	$ 11,228	$ 468	$ 10,760	$ 1,803,408	0.597%
2	2022	$ 18,971	$ 3,407	$ 15,564	$ 1,304	$ 14,260	$ 2,527,764	0.564%
3	2023	$ 21,472	$ 3,864	$ 17,609	$ 374	$ 17,234	$ 2,215,687	0.778%
4	3-Year Average 2021-23					$ 14,085	$ 2,182,286	0.645%
	Test-Year Total Sales & Transport Revenue Exhibit A-15 (MA-14), Schedule E-10, Page 1 of 1							
5	Row 11, Column (h) - Row 11, Column (c).						$ 2,374,807	
6	3-Year Average 2021-23 BDLR							0.645%
7	Projected Uncollectible Accounts Expense							**$ 15,327**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Injuries and Damages Expense
for the Years 2019 through the 12 Months Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-46 (MJF-4)
Page: 1 of 1
Witness: MJFoster
Date: December 2024

Line No.	(a) Program Description		(b) 2019 Actual	(c) 2020 Actual	(d) 2021 Actual	(e) 2022 Actual	(f) 2023 Actual	(g) 2024 Projected	(h) 2025 Projected	(i) 12 Months Ending 10/31/2026
1	Gas Injuries & Damages	[1]	$ 2,310	$ 2,128	$ 2,584	$ 1,934	$ 1,397	$ 2,071	$ 2,071	$ 2,071
2	Internal Legal Costs	[2]	194	94	85	88	98	112	112	112
3	Workers' Compensation	[3]	94	(75)	205	288	(28)	97	97	97
4	Total Gas Injuries & Damages		**$ 2,597**	**$ 2,147**	**$ 2,874**	**$ 2,310**	**$ 1,467**	**$ 2,279**	**$ 2,279**	**$ 2,279**

[1] Gas Injuries & Damages costs are 2019 - 2023 actual expense. 2024, 2025, and Test Year Ending 10/31/2026 used a 5-year average (2019 - 2023).

[2] Legal costs are 2019 - 2023 actual expense. 2024, 2025, and Test Year Ending 10/31/2026 used a 5-year average (2019 - 2023).

[3] Gas Workers' Compensation costs are 2019 - 2023 actual expense. 2024, 2025, and Test Year Ending 10/31/2026 used a 5-year average (2019 - 2023).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Manufactured Gas Plant Amortization Schedule and Direct Project
Management Costs 2005 through the 12 Months Ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-47 (MJF-5)
Page: 1 of 2
Witness: MJFoster
Date: December 2024

Line No.	(a) Item Description	(b) Accounts	(c) 1752107 2005	(d) 1752108 2006	(e) 1752109 2007	(f) 1752110 2008	(g) 1752111 2009	(h) 1752112 2010	(i) 1752113 2011	(j) 1752114 2012	(k) 1752115 2013	(l) 1752116 2014	(m) 1752117 2015	(n) 1752118 2016	(o) 1752119 2017	(p) 1752120 2018	(q) 1752121 2019	(r) 1752122 2020	(s) 1752123 2021	(t) 1752101 2022	(u) 1752102 2023	(v) Forecast 1752103 2024	(w) Forecast 2025	(x) Forecast 2026	(y) 12-Months Ended 10/31/26
1	MGP Expenditures Deferred		$ 8,968	$ 4,627	$ 5,341	3,074	2,910	$ 3,745	$ 7,041	$ 7,616	$ 7,087	$ 5,009	$ 6,386	$ 5,402	$ 27,748	$ 13,904	$ 10,984	$ 10,357	$ 1,087	$ 864	$ 397	$ 997			
2	Insurance Settlements		$ (61)	$ (3,467)	-	(6)	(5)	(1)	(12)	(17)		(5)	(1)	(2)	-	(4)	-	-	-	-	-				
	Amortization Expense																								
3	2005	5890000	-	897	897	897	897	897	897	897	897	897	897												
4	2006	5890000	-	-	462	462	462	462	462	462	462	462	462	462											
5	2007	5890000	-	-	-	534	534	534	534	534	534	534	534	534	534										
6	2008	5890000					307	307	307	307	307	307	307	307	307	307									
7	2009	5890000						291	291	291	291	291	291	291	291	291	291								
8	2010	5890000							374	374	374	374	374	374	374	374	374	374							
9	2011	5890000								704	704	704	704	704	704	704	704	704	704						
10	2012	5890000									761	761	761	761	761	761	761	761	761	761					
11	2013	5890000										709	709	709	709	709	709	709	709	709	709	-	-		-
12	2014	5890000											501	501	501	501	501	501	501	501	501	501			-
13	2015	5890000												639	639	639	639	639	639	639	639	639	639		107
14	2016	5890000													540	540	540	540	540	540	540	540	540	540	540
15	2017	5890000														2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775	2,775
16	2018	5890000															1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
17	2019	5890000																1,098	1,098	1,098	1,098	1,098	1,098	1,098	1,098
18	2020	5890000																	1,036	1,036	1,036	1,036	1,036	1,036	1,036
19	2021	5890000																		109	109	109	109	109	109
20	2022	5890000																			86	86	86	86	86
21	2023	5890000																				40	40	40	40
	2024	5890000																					100	100	100
22	Insurance Settlement Amortization		$ (1,900)	$ (1,906)	$ (2,252)	(2,253)	(2,253)	$ (2,254)	$ (2,254)	$ (386)	$ (387)	$ (362)	$ (359)	$ (353)	$ (5)	$ (4)	(4)	(4)	$ (4)	(2)	(1)	(1)	-	-	-
23	Net amortization expense		$ (1,900)	$ (1,009)	$ (893)	$ (360)	$ (53)	$ 237	$ 611	$ 3,183	$ 3,943	$ 4,677	$ 5,181	$ 4,929	$ 5,355	$ 7,597	$ 8,680	$ 9,487	$ 10,149	$ 9,556	$ 8,882	$ 8,213	$ 7,813	$ 7,174	$ 7,280
24	MGP Expenditures Not Deferred	5890000													$ 533	$ 640	$ 744	$ 481	$ 815	$ 733	$ 949	$ 963	$ 967	$ 923	$ 930

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
MGP Unamortized Balance
for the 12 Months Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-47 (MJF-5)
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Line No.	(a)	(b) (Col. (c)+Col. (d))/2 Average Balance October 31, 2026	(c) 12 Months Ending October 31, 2025	(d) 12 Months Ending October 31, 2026	(e) Original Cost
	Assets:				
1	182 MGP Deferred Exp-2005	0	-	-	8,968
2	182 MGP Deferred Exp-2006	0	-	-	4,627
3	182 MGP Deferred Exp-2007	0	-	-	5,341
4	182 MGP Deferred Exp-2008	0	-	-	3,074
5	182 MGP Deferred Exp-2009	0	-	-	2,910
6	182 MGP Deferred Exp-2010	0	-	-	3,745
7	182 MGP Deferred Exp-2011	0	-	-	7,041
8	182 MGP Deferred Exp-2012	0	-	-	7,616
9	182 MGP Deferred Exp-2013	0	-	-	7,087
10	182 MGP Deferred Exp-2014	0	-	-	5,009
11	182 MGP Deferred Exp-2015	53	106	-	6,386
12	182 MGP Deferred Exp-2016	360	630	90	5,402
13	182 MGP Deferred Exp-2017	4,625	6,012	3,237	27,748
14	182 MGP Deferred Exp-2018	3,708	4,403	3,013	13,904
15	182 MGP Deferred Exp-2019	4,028	4,577	3,478	10,984
16	182 MGP Deferred Exp-2020	4,833	5,351	4,315	10,357
17	182 MGP Deferred Exp-2021	616	670	562	1,087
18	182 MGP Deferred Exp-2022	576	619	533	864
19	182 MGP Deferred Exp-2023	305	324	285	397
20	182 MGP Deferred Exp-2024	864	914	814	997
21	Total Assets:	$ 19,967			
	Liabilities:				
22	253 MGP Deferred Liabilities 2005	0	-	-	(61)
23	253 MGP Deferred Liabilities 2006	0	-	-	(3,467)
24	253 MGP Deferred Liabilities 2007	0	-	-	-
25	253 MGP Deferred Liabilities 2008	0	-	-	(6)
26	253 MGP Deferred Liabilities 2009	0	-	-	(5)
27	253 MGP Deferred Liabilities 2010	0	-	-	(1)
28	253 MGP Deferred Liabilities 2011	0	-	-	(12)
29	253 MGP Deferred Liabilities 2012	0	-	-	(17)
30	253 MGP Deferred Liabilities 2013	0	-	-	-
31	253 MGP Deferred Liabilities 2014	0	-	-	(5)
32	253 MGP Deferred Liabilities 2015	0	-	-	(1)
33	253 MGP Deferred Liabilities 2016	0	-	-	(2)
34	253 MGP Deferred Liabilities 2017	0	-	-	-
35	253 MGP Deferred Liabilities 2018	1	1	-	(4)
36	253 MGP Deferred Liabilities 2019	0	-	-	-
37	253 MGP Deferred Liabilities 2020	0			-
38	253 MGP Deferred Liabilities 2021	0			-
39	253 MGP Deferred Liabilities 2022	0			
40	253 MGP Deferred Liabilities 2023	0			
41	253 MGP Deferred Liabilities 2024	0			
42	Total Liabilities:	$ 1			
43	**Unamortized Balance to be included in rate base: (000)**	**$ 19,967**			

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Organization Chart
Affiliate Group of Companies Doing Business With Consumers Energy Company 2023

Case No.: U-21806
Exhibit No.: A-48 (MJF-6)
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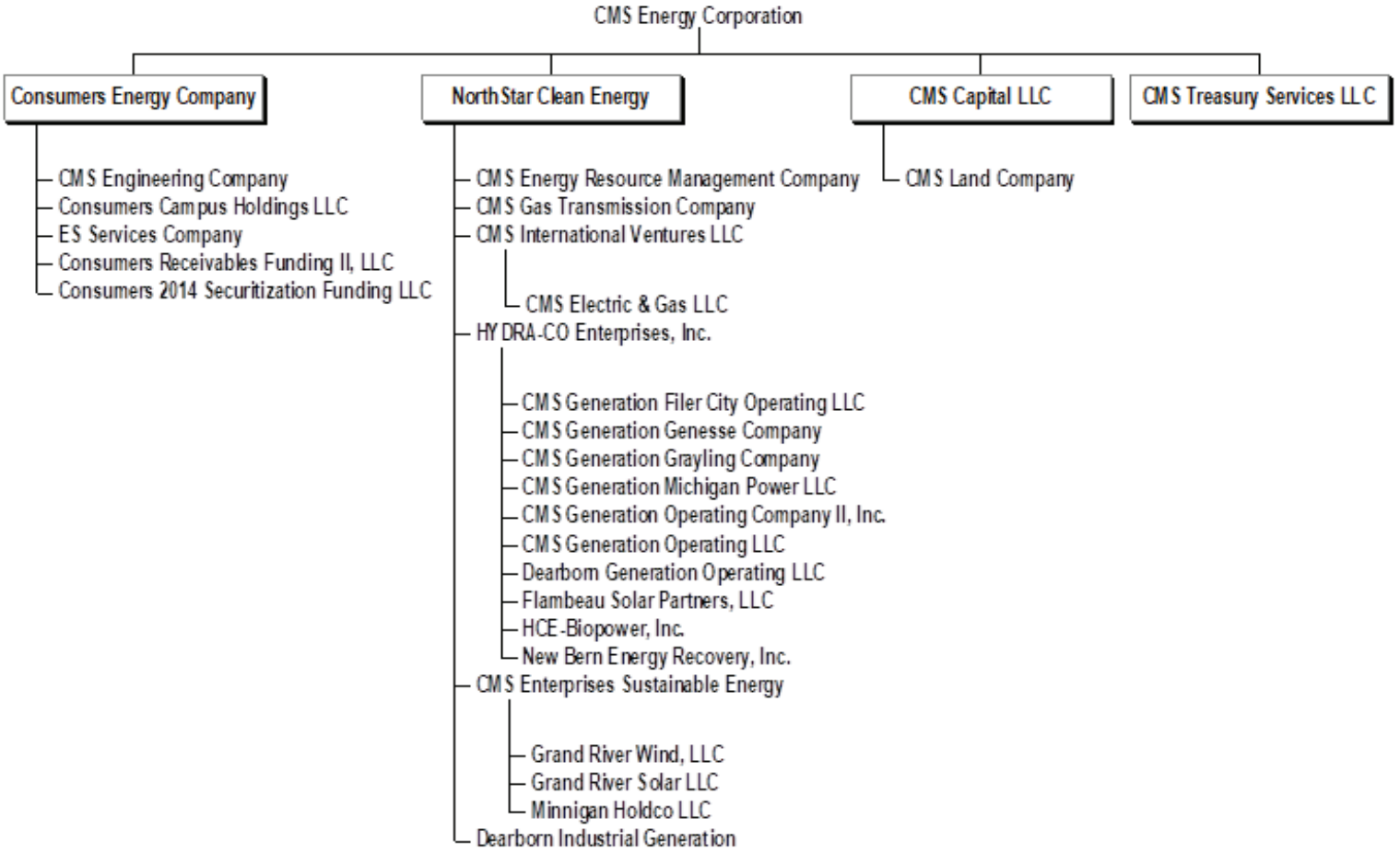

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Purpose of Business
Affiliate Group of Companies Doing Business With Consumers Energy Company 2023

Case No.: U-21806
Exhibit No.: A-48 (MJF-6)
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Line No.	Company Name	Affiliation, Percentage Ownership	Purpose of Business
	(a)	(b)	(c)
1	CMS Capital LLC	CMS Energy Sub, 100%	Formed to assist in securing financing for CMS Energy Corporation and its subsidiaries and affiliates
2	CMS Electric & Gas LLC	CMS Enterprises Sub, 100%	Formed to hold a portion of CMS Energy's international interests in projects located in South America
3	CMS Energy Corporation	Parent Company	Formed for the purpose of a Holding Company for both regulated and non-regulated businesses
4	CMS Energy Resource Management Co	CMS Enterprises Sub, 100%	Involved in providing gas, electric, oil and coal marketing, risk management and energy management services
5	CMS Engineering Company	Consumers Sub, 100%	Engaged in offering design, engineering project management and related construction services to natural gas utilities, natural gas exploration and production companies, and other energy businesses
6	NorthStar Clean Energy	CMS Energy Sub, 100%	Owns subsidiaries engaged in the development, acquisition and management of energy-related businesses and projects worldwide - FORMERLY KNOW AS CMS ENTERPRISES - NAME CHANGE ONLY
7	CMS Enterprises Sustainable Energy	CMS Enterprises Sub, 100%	Organized to engage in wind and solar projects
8	CMS Gas Transmission Company	CMS Enterprises Sub, 100%	Organized to engage in the transmission and processing of natural gas
9	CMS Generation Filer City Operating LLC	CMS Enterprises Sub, 100%	Formed to operate a coal and wood waste-fueled power plant
10	CMS Generation Michigan Power LLC	CMS Enterprises Sub, 100%	Owns generating units which are to be sited in Michigan for the purpose of generating power during peak demand periods
11	CMS Generation Operating Company II, Inc.	CMS Enterprises Sub, 100%	Involved in the operation of various power plants throughout the United States
12	CMS Generation Operating LLC	CMS Enterprises Sub, 100%	Involved in the operation of various power plants including Grayling and Genesee
13	CMS International Ventures LLC	CMS Enterprises Sub, 98.5%	Formed to own, manage and sell certain of CMS Energy's international investments
14	CMS Land Company	CMS Capital Sub, 100%	Formed to act as a repository for any unused real property formerly owned by Consumers Power and hold the same for possible non-utility development
15	CMS Treasury Services LLC	CMS Energy Sub, 100%	Formed to handle cash management functions/intercompany banking operations for CMS and certain of its subsidiaries and affiliates. No invoicing or payments made to this company
16	Consumers Campus Holdings LLC	Consumers Sub, 100%	The lessee in the synthetic lease financing of the new Consumers Energy Company office building. No invoicing or payments made to this company
17	Consumers Reveivable Funding II LLC	Consumers Sub, 100%	Buys certain accounts receivable from Consumers and sells them to a third party.

Line No.	Company Name	Affiliation, Percentage Ownership	Purpose of Business
	(a)	(b)	(c)
18	Consumers 2014 Securitization Funding LLC	Consumers Sub, 100%	Formed to engage in Securitization Financing
19	Craven County Wood Limited Partnership	CMS Enterprises, 50%	Owns power plant fueled on waste-wood and poultry waste.
20	Dearborn Generation Operating LLC	CMS Enterprises Sub, 100%	Operates the Ford/Rouge project (both the base units and the peaking unit)
21	Dearborn Industrial Generation LLC	CMS Enterprises Sub, 100%	Parent of DIG (100%) Operates Air permit for DIG
22	ES Services Company	Consumers Sub, 100%	For the purpose of offering design, engineering project management and related services primarily to electric utilities and generation facilities and building Solar projects for customers.
23	Flambeau Solar Partners, LLC	CMS Enterprises Sub, 100%	Formed to develop a solar photovoltaic electric generating system in Phillips, Wisconsin
24	Genesee Power Station LP	CMS Enterprises, 50%	Formed to develop, construct and operate a waste wood cogeneration facility
25	Grand River Wind, LLC	CMS Enterprises Sustainable Energy, 100%	Develops and operates Wind assets/projects
26	Grand River Solar, LLC	CMS Enterprises Sustainable Energy, 100%	Develops and owns Solar assets/projects
27	Grayling Generating Station LP	CMS Enterprises, 50%	Owns a waste-wood fueled power plant
28	HCE - Biopower, Inc	CMS Enterprises Sub, 100%	Formed to hold partnership interests in various power projects.
29	HYDRA-CO Enterprises, Inc.	CMS Enterprises Sub, 100%	Engaged in the ownership and/or operation, by itself or with others, of one or more cogeneration, small hydro or alternate energy production facilities thru partnership interests and ownership of domestic corporations
30	Minnigan Holdings Co	CMS Enterprises, 50%	Joint venture formed to develop Renewable Energy Projects.
31	New Bern Energy Recovery, Inc.	CMS Enterprises Sub, 100%	Formed to participate as a general partner in the Craven County Wood Energy limited partnership formed to construct, operate and own a wood-fired electric generating facility
32	T.E.S. Filer City Station LP	CMS Enterprises, 50%	Owns a wood chip and coal cogeneration plant

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Costs Billed to Affiliated Companies
for the Year Ended December 31, 2023

Case No.: U-21806
Exhibit No.: A-49 (MJF-7)
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Date: December 2024

Line No.	Company Name	Affiliation	Description: Nature of Goods & Services	Classified to Operating Income (1)	Classified to Other Operating Income (2)	Classified to Balance Sheet (3)	Total	Account Number See Footnotes (1), (2), (3)	Billing Method
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	CMS Capital LLC	CMS Energy Sub	Professional Svcs	$ -	$ -	$ 25	$ 25		Full Cost
2	CMS Electric & Gas LLC	CMS Enterprises Sub	Professional Svcs, Emp Benefits	-	-	-	-		Full Cost
3	CMS Energy Corporation	Parent Company	Professional Svcs, Emp Benefits	582,982	17,794	3,858,977	4,459,753		Full Cost
4	CMS Energy Resource Management Co.	CMS Enterprises Sub	Professional Svcs, Emp Benefits	37,246	1,987	288,658	327,891		Full Cost
5	CMS Engineering Company	Consumers Sub	Professional Svcs	-	-	25	25		Full Cost
6	NorthStar Clean Energy	CMS Energy Sub	Professional Svcs, Emp Benefits	631,395	32,870	7,152,556	7,816,821		Full Cost
7	CMS Gas Transmission Company	CMS Enterprises Sub	Professional Svcs, Emp Benefits	1,203	166	34,516	35,885		Full Cost
8	CMS Generation Filer City Operating LLC	CMS Enterprises Sub	Professional Svcs, Emp Benefits	19,430	6,319	1,303,590	1,329,339		Full Cost
9	CMS Generation Michigan Power LLC	CMS Enterprises Sub	Operation & Maintenance Svcs	-	-	1,180,153	1,180,153		Full Cost
10	CMS Generation Operating Company II, Inc.	CMS Enterprises Sub	Professional Svcs, Emp Benefits	20,976	6,389	1,312,391	1,339,756		Full Cost
11	CMS Generation Operating LLC	CMS Enterprises Sub	Professional Svcs, Emp Benefits	56,088	23,385	4,850,135	4,929,608		Full Cost
12	CMS International Ventures LLC	CMS Enterprises Sub	Professional Svcs, Emp Benefits	-	67	13,705	13,772		Full Cost
13	CMS Land Company	CMS Capital Sub	Professional Svcs, Emp Benefits	8,878	334	62,239	71,451		Full Cost
14	Craven County Wood Limited Partnership		Professional Svcs	-	-	161,183	161,183		Full Cost
15	Dearborn Generation Operating LLC	CMS Enterprises Sub	Professional Svcs	48,229	13,285	2,884,728	2,946,242		Full Cost
16	Dearborn Industrial Generation	CMS Enterprises Sub	Professional Svcs, Emp Benefits	-	-	5,213	5,213		Full Cost
17	ES Services Company	Consumers Sub	Professional Svcs	112,778	2,783	488,155	603,716		Full Cost
18	Genesee Power Station LP	CMS Enterprises	Operation & Maintenance Svcs	-	-	33,634	33,634		Full Cost
19	Grayling Generating Station LP	CMS Enterprises	Operation & Maintenance Svcs	-	-	30,117	30,117		Full Cost
20	HYDRA-CO Enterprises, Inc.	CMS Enterprises Sub	Professional Svcs, Emp Benefits	10,345	609	122,063	133,017		Full Cost
21	Minnigan Holdings Co		Professional Svcs	-	-	-	-		Full Cost
22	New Bern Energy Recovery, Inc.	CMS Enterprises Sub	Professional Svcs, Emp Benefits	717	52	10,553	11,322		Full Cost
23	T.E.S. Filer City Station LP	CMS Enterprises	Operation & Maintenance Svcs	-	-	73,407	73,407		Full Cost
24	Total			$ 1,530,267	$ 106,040	$ 23,866,023	$ 25,502,330		

Notes:
(1) Operating Income- Accounts 920, 921, 923-926, 930, 931, 935, 408, 456, 495
(2) Other Operating Income- Account 419
(3) Balance Sheet- Account 146

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Payments Made to Affiliated Companies
for the Year Ended December 31, 2023

Case No.: U-21806
Exhibit No.: A-49 (MJF-7)
Page: 2 of 2
Witness: MJFoster
Date: December 2024

Line No.	Company Name	Affiliation	Description: Nature of Goods & Services	Classified to Operating Income	Classified to Other Operating Income	Classified to Balance Sheet	Total	Account Number	Billing Method
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	CMS Energy Corporation	Parent Company	Restricted Stock	$ -	$ 26,957,046	$ -	$ 26,957,046	426.5	Full Cost
			Executive Services	8,191			8,191	923	Full Cost
2	CMS Generation Oper	CMS Enterprises	Executive Services	877	-	-	877		
3	Genesee Power Station LP	CMS Enterprises	Energy Purchases	20,190,904	-	-	20,190,904	555	Full Cost
4	Grayling Generating Station LP	CMS Enterprises	Energy Purchases	20,726,224	-	-	20,726,224	555	Full Cost
5	T.E.S. Filer City Station LP	CMS Enterprises	Energy Purchases	46,317,456	-	-	46,317,456	555	Full Cost
6	Total			$ 87,243,652	$ 26,957,046	$ -	$ 114,200,698		

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Impact on Gas Operations for Costs Billed to Affiliated Companies
for the Year Ended December 31, 2023

Case No.: U-21806
Exhibit No.: A-50 (MJF-8)
Page: 1 of 1
Witness: MJFoster
Date: December 2024

Line No.	Expense Description	Total Billed	Gas Operations	Account
	(a)	(b)	(c)	(d)
1	Administrative & General Salaries	$ 245,871	$ 88,433	920
2	Office Supplies and Expenses	60,460	20,296	921
3	Outside Services	141,074	40,593	923
4	Property Insurance	4,031	1,450	924
5	Injuries and Damages	8,061	2,899	925
6	Pension and Benefits	193,473	104,702	926
7	Miscellaneous General Expenses	20,153	7,249	930
8	GO Rents	4,031	1,450	931
9	Maintenance of General Plant	36,276	11,598	935
10	Payroll Taxes	322,455	127,254	408
11	Property Taxes	76,584	31,371	408
12	Depreciation	153,166	56,620	495
13	Return on Investment on Utility Assets	157,197	48,969	456
14	Other Comp & Benefits	108,826	45,102	426.5
15	**Total**	$ 1,531,658	$ 587,986	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Impact on Gas Operations for Payments Made to Affiliated Companies
for the Year Ended December 31, 2023

Case No.: U-21806
Exhibit No.: A-51 (MJF-9)
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Line No.	Company	Transaction	Total Paid	Gas Operations	Account
	(a)	(b)	(c)	(d)	(e)
1	CMS Energy Company	Corporate Insurance & Executive Serv	$ 8,191	$ 2,867	923/583/593
2		Subtotal	8,191	2,867	
3	CMS Generation Oper	Corporate Insurance & Executive Serv	$ 877	$ 307	923/583/593
4			877	307	
5	Genesee Power Station LP	Energy Purchases	$ 20,190,904	-	
6			20,190,904	-	
7	Grayling Generating Station LP	Energy Purchases	$ 20,726,224	-	
8			20,726,224	-	
9	T.E.S. Filer City Station LP	Energy Purchases	$ 46,317,456	-	
10			46,317,456	-	
11			87,243,652	3,174	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Affiliated Companies - Rate of Return on Common Equity
for the Year Ended December 31, 2023

Case No.: U-21806
Exhibit No.: A-52 (MJF-10)
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Witness: MJFoster
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Line No.	Company Name	Net Income	Average Common Equity	Return On Common Equity
1	CMS Energy Corporation Consolidated (1)	$ 876,928,887	$ 7,055,015,455	12.43%
2	CMS Enterprises Company Consolidated	59,663,516	785,420,607	7.60%
3	CMS Enterprises Sustainable Energy	47,876,856	386,662,358	12.38%
4	CMS Capital LLC Consolidated (1)	1,336,770	40,339,517	3.31%
5	CMS Energy Resource Management Co Consolidated	7,136,498	25,214,929	28.30%
6	CMS Gas Transmission Company Consolidated	4,461,268	58,961,121	7.57%
7	CMS International Ventures LLC Consolidated	156,126	2,362,311	6.61%
8	CMS Treasury Services	2,969,184	24,067,283	12.34%
9	Dearborn Industrial Generation LLC	4,179,984	74,334,467	5.62%
10	HYDRA-CO Enterprises, Inc. Consolidated	9,009,425	111,755,774	8.06%
11	CMS Engineering Company	(19)	272,498	-0.01%
12	ES Services Company	(106,399)	12,039,202	-0.88%

(1) CMS Energy and CMS Capital had income from discontinued operations during 2023. Below is the rate of return on common equity based on net income from continuing operations, which excludes income from discontinued operations.

- CMS Capital & Subs	475,607	40,339,517	1.18%

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

S&P Global Market Intelligence Ranking of Consumers Energy Gas A&G Costs for 2023

Ranked by A&G per Customer (less Pension and Benefits)

(Companies over 500K Customers)

Case No.: U-21806
Exhibit No.: A-53 (MJF-11)
Page: 1 of 1
Witness: MJFoster
Date: December 2024

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	Company Name	Total Customers (actual)	Total Admin & Gen: O&M Expense ($000)	Total Admin & Gen: Pension & Benefits ($000)	Total Admin &Gen: Excluding Pension & Benefits (d) - (e) ($000)	Total Admin & Gen: Excluding Pension & Benefits $/customer ($) (f)/(c) x $1,000	$/Customer Ranking
1	Wisconsin Gas LLC	653,320	$ 25,375	$ 5,998	$ 19,377	$ 29.66	**1**
2	**Consumers Energy Company**	**1,816,713**	**43,453**	**(29,077)**	**72,530**	**39.92**	**2**
3	Peoples Natural Gas Company LLC	604,601	45,829	19,942	25,887	42.82	**3**
4	Peoples TWP LLC	604,601	45,829	19,942	25,887	42.82	**4**
5	Public Service Electric and Gas Company	1,842,003	86,893	(5,438)	92,331	50.13	**5**
6	PECO Energy Company	550,059	34,628	4,630	29,998	54.54	**6**
7	Ameren Illinois Company	802,310	28,347	(21,999)	50,346	62.75	**7**
8	Indiana Gas Company, Inc.	651,351	51,997	7,288	44,709	68.64	**8**
9	Puget Sound Energy, Inc.	874,918	79,864	12,204	67,660	77.33	**9**
10	DTE Gas Company	1,228,207	139,633	32,830	106,803	86.96	**10**
11	Southern California Gas Company	6,163,251	786,676	243,883	542,793	88.07	**11**
12	Consolidated Edison Company of New York, Inc.	1,083,408	61,116	(35,813)	96,929	89.47	**12**
13	Texas Gas Service Company, Inc.	685,232	75,912	11,281	64,631	94.32	**13**
14	National Fuel Gas Distribution Corporation	694,550	87,831	21,030	66,801	96.18	**14**
15	Kansas Gas Service Company, Inc.	642,397	92,397	19,944	72,453	112.79	**15**
16	Northwest Natural Gas Company	796,379	129,670	34,381	95,289	119.65	**16**
17	Niagara Mohawk Power Corporation	596,999	84,643	10,484	74,159	124.22	**17**
18	Baltimore Gas and Electric Company	583,160	103,419	20,725	82,694	141.80	**18**
19	UGI Utilities, Inc.	585,370	98,710	14,137	84,573	144.48	**19**
20	Pacific Gas and Electric Company	4,593,057	854,898	169,307	685,591	149.27	**20**
21	Northern Illinois Gas Company	2,056,968	340,296	31,596	308,700	150.08	**21**
22	New Jersey Natural Gas Company	551,465	107,085	16,738	90,347	163.83	**22**
23	Boston Gas Company	965,241	199,287	31,774	167,513	173.55	**23**
24	KeySpan Gas East Corporation	578,186	131,808	10,767	121,041	209.35	**24**
25	San Diego Gas & Electric Company	512,632	134,823	22,532	112,291	219.05	**25**
26	The Brooklyn Union Gas Company	1,191,169	309,619	28,969	280,650	235.61	**26**
27	The Peoples Gas Light and Coke Company	834,145	314,471	19,483	294,988	353.64	**27**

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1	Service Revenue			2,284,471	1,631,131	271,029	224,497	55,417	34,864	27,199	30,204	10,129
2	Other Revenue			28,666	19,112	3,376	3,034	804	716	556	760	309
3	Total Revenue			2,313,137	1,650,243	274,406	227,531	56,220	35,580	27,755	30,965	10,438
4	Expenses:											
5	Cost of Gas Sold (COGS)			737,588	520,137	98,061	92,931	26,459	-	-	-	-
6	O & M Expense			297,904	230,860	29,732	17,093	4,004	6,289	4,199	4,192	1,535
10	Depreciation & Amortization Expense			384,404	278,800	40,561	29,007	7,153	10,801	7,462	7,736	2,884
14	Lost and Unaccounted for (LAUF) Gas			12,709	8,962	1,690	1,601	456	-	-	-	-
18	Taxes			330,836	235,695	36,787	28,322	6,426	8,179	6,211	6,846	2,371
22	Company Use			5,502	3,880	731	693	197	-	-	-	-
26	Total Expenses			1,768,943	1,278,334	207,562	169,647	44,695	25,269	17,872	18,774	6,790
27	Net Operating Income			544,194	371,908	66,844	57,884	11,525	10,310	9,884	12,190	3,648
28	Test Year AFUDC	CWIP	207	1,298	866	149	130	34	39	28	36	14
32	Adjusted Net Operating Income			545,491	372,775	66,993	58,015	11,559	10,349	9,912	12,226	3,662
33	Total Rate Base			11,750,739	8,386,661	1,261,470	943,636	236,324	332,546	233,967	258,063	98,072
37	Return on Rate Base @ 6.22%			730,837.85	521,609	78,457	58,689	14,698	20,683	14,552	16,050	6,100
41	Income Deficiency/(Sufficiency)			185,346	148,834	11,464	675	3,139	10,334	4,640	3,824	2,437
42	Revenue Deficiency/(Sufficiency)			248,008	199,152	15,340	903	4,200	13,828	6,208	5,116	3,261
43	Rev Requirement/Total Cost of Service			$ 2,561,146	$ 1,849,395	$ 289,745	$ 228,434	$ 60,420	$ 49,407	$ 33,963	$ 36,081	$ 13,700
44	Less: Cost of Gas Sold (Test Yr)			737,588	520,137	98,061	92,931	26,459	-	-	-	-
45	Less: Miscellaneous Revenue (TY)			28,666	19,112	3,376	3,034	804	716	556	760	309
46	**Proposed Rate Design Revenue**			**1,794,891**	**1,310,146**	**188,308**	**132,469**	**33,158**	**48,691**	**33,407**	**35,321**	**13,391**
47	Customer			689,169	569,784	63,491	27,537	5,900	9,885	5,801	5,051	1,720
48	Demand			1,030,350	681,203	117,079	100,763	26,239	37,543	26,755	29,413	11,354
49	Energy			75,373	59,158	7,738	4,169	1,019	1,263	851	857	317

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	Proposed Rate Design Revenue Summary											
1	Transmission Related Cost			415,032	253,005	48,687	46,211	12,512	16,340	12,706	17,969	7,602
2	Customer			47,096	$ 28,593	$ 5,640	$ 5,425	$ 1,397	$ 1,747	$ 1,427	$ 2,034	$ 833
3	Demand			357,638	$ 218,017	$ 41,814	$ 39,614	$ 10,798	$ 14,243	$ 11,003	$ 15,543	$ 6,605
4	Energy			10,298	$ 6,395	$ 1,233	$ 1,172	$ 317	$ 350	$ 276	$ 391	$ 164
5	Storage Related Cost			256,882	164,285	31,514	30,234	8,201	7,068	5,273	7,424	2,884
6	Customer			27,058	$ 17,220	$ 3,367	$ 3,290	$ 855	$ 696	$ 550	$ 788	$ 292
7	Demand			223,044	$ 142,704	$ 27,309	$ 26,139	$ 7,128	$ 6,200	$ 4,592	$ 6,452	$ 2,521
8	Energy			6,780	$ 4,362	$ 838	$ 805	$ 218	$ 173	$ 130	$ 184	$ 71
9	Distribution Related Cost			1,122,977	892,855	108,107	56,025	12,445	25,283	15,429	9,929	2,905
10	Customer			615,015	$ 523,971	$ 54,484	$ 18,822	$ 3,648	$ 7,442	$ 3,824	$ 2,230	$ 595
11	Demand			449,668	$ 320,483	$ 47,955	$ 35,010	$ 8,313	$ 17,101	$ 11,160	$ 7,417	$ 2,228
12	Energy			58,295	$ 48,401	$ 5,668	$ 2,192	$ 484	$ 740	$ 445	$ 282	$ 83
13	Total			1,794,891	1,310,146	188,308	132,469	33,158	48,691	33,407	35,321	13,391
14	Customer			689,169	569,784	63,491	27,537	5,900	9,885	5,801	5,051	1,720
15	Demand			1,030,350	681,203	117,079	100,763	26,239	37,543	26,755	29,413	11,354
16	Energy			75,373	59,158	7,738	4,169	1,019	1,263	851	857	317
17	Mcf Thruput			307,735,810	157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
18	Customer Count			1,846,892	1,709,595	119,353	15,633	539	1,282	359	128	3

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1	Production Plant	DEMAND	102	122,449	86,350	16,279	15,428	4,393	-	-	-	-
5	Storage Plant	DEMAND	1071	1,638,445	1,040,615	200,871	193,852	51,822	46,756	35,355	49,981	19,193
9	Transmission To/From Storage	DEMAND	1071	1,789,747	1,136,710	219,420	211,754	56,607	51,073	38,620	54,597	20,965
13	Other Transmission	DEMAND	1041	1,533,933	878,585	171,534	160,884	42,615	81,039	65,452	92,926	40,897
17	Total Transmission Plant			3,323,679	2,015,296	390,955	372,638	99,222	132,113	104,072	147,522	61,863
21	Distribution Plant - Other	DEMAND	1051	-	-	-	-	-	-	-	-	-
25	Distribution Plant - Other - Fee Land & Easements (374)	DEMAND	1041	33,181	19,005	3,710	3,480	922	1,753	1,416	2,010	885
29	Distribution Plant - Other - Structures and Improvements (375)	DEMAND	1041	69,188	39,628	7,737	7,257	1,922	3,655	2,952	4,191	1,845
33	Distribution Plant - Other - Compressor Station Equipment (377)	DEMAND	1041	11,885	6,807	1,329	1,247	330	628	507	720	317
37	Distribution Plant - Other - M & R General (378)	DEMAND	1041	355,404	203,564	39,744	37,276	9,874	18,776	15,165	21,530	9,476
41	Distribution Plant - Other - Meter Installations (382)	CUST	108	34,919	30,794	3,001	717	115	211	63	18	1
45	Mains - High Pressure Capable	DEMAND	1051	372,982	209,204	41,377	38,608	10,464	19,386	16,099	26,152	11,692
49	Mains - Non-High Pressure Capable	DEMAND	1061	2,447,265	1,572,389	294,152	275,407	64,907	130,973	82,801	26,571	65
53	Services & Meters	CUST	108	5,354,052	4,721,624	460,150	109,871	17,598	32,319	9,672	2,718	99
57	Total Distribution Plant			8,678,876	6,803,016	851,200	473,862	106,133	207,701	128,675	83,910	24,379
61	Total Plant In Service excl Gen, Com, & Int			13,763,449	9,945,275	1,459,305	1,055,780	261,568	386,570	268,102	281,414	105,435
65	Gen, Com, & Int Plant and PHFFU	PLANT	206	820,939	593,199	87,042	62,973	15,602	23,057	15,991	16,785	6,289
69	Total Test Year Plant in Service			14,584,387	10,538,474	1,546,347	1,118,753	277,170	409,627	284,093	298,199	111,723

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1	Production CWIP	PROD_PLANT	202	-	-	-	-	-	-	-	-	-
5	Storage CWIP	STOR_PLANT	1071	161,299	102,445	19,775	19,084	5,102	4,603	3,481	4,920	1,889
9	Transmission CWIP	TRAN_PLANT	204	53,976	32,728	6,349	6,052	1,611	2,145	1,690	2,396	1,005
13	Distribution CWIP	DIST_PLANT	205	42,995	33,702	4,217	2,348	526	1,029	637	416	121
17	General, Common & Intangible and PHFFU CWIP	PLANT	206	64,606	46,684	6,850	4,956	1,228	1,815	1,258	1,321	495
21	Total CWIP			322,877	215,559	37,191	32,439	8,467	9,592	7,067	9,053	3,510
25	Production Accumulated Depreciation	PROD_PLANT	202	(8,245)	(5,814)	(1,096)	(1,039)	(296)	-	-	-	-
29	Storage Accumulated Depreciation	STOR_PLANT	1071	(253,855)	(161,230)	(31,122)	(30,035)	(8,029)	(7,244)	(5,478)	(7,744)	(2,974)
33	Transmission Accumulated Depreciation	TRAN_PLANT	204	(615,340)	(373,108)	(72,381)	(68,990)	(18,370)	(24,459)	(19,268)	(27,312)	(11,453)
37	Distribution Accumulated Depreciation	DIST_PLANT	205	(3,209,490)	(2,515,788)	(314,778)	(175,236)	(39,248)	(76,809)	(47,585)	(31,030)	(9,015)
41	General, Common & Intangible and PHFFU Accumulated Depreciation	PLANT	206	(578,782)	(418,220)	(61,367)	(44,398)	(10,999)	(16,256)	(11,274)	(11,834)	(4,434)
45	Total Accumulated Depreciation			(4,665,713)	(3,474,160)	(480,744)	(319,697)	(76,942)	(124,768)	(83,604)	(77,921)	(27,876)
49	Cash & Cash Equivalents	ENERGY	209	696,014	533,440	69,438	42,434	10,023	15,742	10,523	10,547	3,867
53	Accounts Receivable	ENERGY	111	109,689	78,319	13,014	10,779	2,661	1,674	1,306	1,450	486
57	Materials and Supplies	O&M (EXC. A&G)	209	55,983	42,906	5,585	3,413	806	1,266	846	848	311

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1	Gas Stored Underground- Recoverable Base Gas	STOR_PLANT	1071	173,941	110,474	21,325	20,580	5,502	4,964	3,753	5,306	2,038
5	Gas Stored Underground- Working Gas	STOR_PLANT	102	208,094	146,745	27,666	26,218	7,465	-	-	-	-
9	Real & Personal Property Taxes	PLANT	206	176,164	127,294	18,678	13,513	3,348	4,948	3,432	3,602	1,350
13	Other Assets	PLANT	206	-	-	-	-	-	-	-	-	-
17	Deferred Debits	PLANT	206	466,865	337,350	49,501	35,813	8,873	13,113	9,094	9,546	3,576
21	Total Assets			1,886,750	1,376,528	205,206	152,750	38,677	41,707	28,954	31,299	11,628
25	Accounts Payable	ENERGY	102	234,904	165,651	31,230	29,596	8,427	-	-	-	-
29	Dividends Declared	PLANT	215	14,780	10,144	1,805	1,550	309	281	266	326	98
33	Customer Deposits	ENERGY	111	11,793	8,913	1,329	962	234	156	105	74	19
37	Accrued Interest	PLANT	206	42,561	30,754	4,513	3,265	809	1,195	829	870	326
41	Accrued Taxes - Federal	PLANT	215	771	529	94	81	16	15	14	17	5
45	Accrued Taxes - State	PLANT	215	(98)	(67)	(12)	(10)	(2)	(2)	(2)	(2)	(1)
49	Accrued Taxes - R&PP Tax & Other	PLANT	206	11,726	8,473	1,243	899	223	329	228	240	90
53	Other Liabilities	PLANT	206	30,215	21,833	3,204	2,318	574	849	589	618	231

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1	Deferred Credits	PLANT	206	31,718	22,919	3,363	2,433	603	891	618	649	243
5	Total Liabilities			378,369	269,150	46,768	41,095	11,192	3,714	2,647	2,791	1,012
9	Total Working Capital			1,508,380	1,107,378	158,438	111,656	27,485	37,993	26,307	28,508	10,616
13	Test Year Unamortized MGP Expense - Net	PLANT	206	19,967	14,428	2,117	1,532	379	561	389	408	153
17	Test Year Retainers & Customer Advances-Net	DIST_PLANT	205	(19,159)	(15,018)	(1,879)	(1,046)	(234)	(459)	(284)	(185)	(54)
21	Adjustments to Rate Base			808	(590)	238	486	145	102	105	223	99
25	Total Test Year Rate Base			11,750,739	8,386,661	1,261,470	943,636	236,324	332,546	233,967	258,063	98,072
29	Production O&M	PROD_PLANT	202	-	-	-	-	-	-	-	-	-
33	Storage O&M	STOR_PLANT	1071	23,968	15,223	2,938	2,836	758	684	517	731	281
37	Transmission O&M	TRAN_PLANT	204	34,344	20,824	4,040	3,850	1,025	1,365	1,075	1,524	639
41	Distribution O&M	DIST_PLANT	205	128,141	100,445	12,568	6,996	1,567	3,067	1,900	1,239	360
45	Customer Accounting O&M	CUST	110	36,633	33,658	2,350	308	11	221	66	19	1
49	Customer Service & Information O&M	CUST	109	394	365	25	3	0	0	0	0	0
53	Customer Assistance O&M	CUST	109	1,687	1,561	109	14	0	1	0	0	0

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1	Total Test Year O&M Expense			225,167	172,076	22,030	14,008	3,362	5,338	3,559	3,513	1,281
2	Customer			118,281	97,954	10,288	4,670	984	2,127	1,246	788	224
3	Demand			106,887	74,123	11,742	9,338	2,377	3,212	2,313	2,725	1,056
4	Energy			-	-	-	-	-	-	-	-	-
5	Administrative & General Expense	O&M (EXC. A&G)	209	82,571	63,284	8,238	5,034	1,189	1,868	1,248	1,251	459
6	Customer		209	43,375	33,243	4,327	2,644	625	981	656	657	241
7	Demand		209	39,197	30,041	3,910	2,390	564	887	593	594	218
8	Energy		209	-	-	-	-	-	-	-	-	-
9	Business Customer Care	CUST	114	1,776	-	1,377	348	12	28	8	3	0
13	Customer Contact Center	CUST	115	13,243	12,786	451	5	0	1	-	-	-
17	Interest on Customer Deposits	ENERGY	111	237	179	27	19	5	3	2	1	0
21	Test Year Uncollectible Expense	ENERGY	113	15,327	13,649	1,569	101	9	(3)	2	-	-
25		ENERGY	209	-	-	-	-	-	-	-	-	-
29	Production- Pension & Benefits Expense	PROD_PLANT	202	-	-	-	-	-	-	-	-	-
33	Storage- Pension & Benefits Expense	STOR_PLANT	1071	(2,414)	(1,533)	(296)	(286)	(76)	(69)	(52)	(74)	(28)
37	Transmission- Pension & Benefits Expense	TRAN_PLANT	204	(3,766)	(2,284)	(443)	(422)	(112)	(150)	(118)	(167)	(70)
41	Distribution- Pension & Benefits Expense	DIST_PLANT	205	(21,341)	(16,729)	(2,093)	(1,165)	(261)	(511)	(316)	(206)	(60)
45	Customer Accounting (Billing)- Pension & Benefits Expense	CUST	110	(4,264)	(3,918)	(274)	(36)	(1)	(26)	(8)	(2)	(0)
49	Customer Service- Pension & Benefits Expense	CUST	109	(221)	(205)	(14)	(2)	(0)	(0)	(0)	(0)	(0)
53	Sales Expense- Pension & Benefits Expense	O&M (EXC. A&G)	209	(10)	(8)	(1)	(0)	(0)	(0)	(0)	(0)	(0)
57	Administrative & General- Pension & Benefits Expense	CUST	209	(8,400)	(6,438)	(838)	(512)	(121)	(190)	(127)	(127)	(47)
61	Total Test Year Pension & Benefits Expense			(40,418)	(31,115)	(3,959)	(2,423)	(572)	(945)	(621)	(577)	(205)
65	Production- Payroll Tax	PROD_PLANT	202	-	-	-	-	-	-	-	-	-

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Line. No.	(a) Summary Description	(b) Classification	(c) Allocation	(d) Total	(e) Residential	(f) Rate GS-1	(g) Rate GS-2	(h) Rate GS-3	(i) Rate ST	(j) Rate LT	(k) Rate XLT	(l) Rate XXLT
1	Storage- Payroll Tax	STOR_PLANT	1071	876	556	107	104	28	25	19	27	10
5	Transmission- Payroll Tax	TRAN_PLANT	204	1,367	829	161	153	41	54	43	61	25
9	Distribution- Payroll Tax	DIST_PLANT	205	7,744	6,070	760	423	95	185	115	75	22
13	Customer Accounting (Billing)- Payroll Tax	CUST	110	1,547	1,422	99	13	0	9	3	1	0
17	Customer Service- Payroll Tax	CUST	109	80	74	5	1	0	0	0	0	0
21	Sales Expense- Payroll Tax	O&M (EXC. A&G)	209	4	3	0	0	0	0	0	0	0
25	Administrative & General- Payroll Tax	CUST	209	3,048	2,336	304	186	44	69	46	46	17
29	Total Payroll Tax			14,666	11,291	1,437	879	208	343	225	209	74
33	Production- Depreciation & Amortization Exp	PROD_PLANT	202	-	-	-	-	-	-	-	-	-
37	Storage- Depreciation & Amortization Exp	STOR_PLANT	1071	39,352	24,994	4,825	4,656	1,245	1,123	849	1,200	461
41	Transmission- Depreciation & Amortization Exp	TRAN_PLANT	204	76,856	46,601	9,040	8,617	2,294	3,055	2,407	3,411	1,431
45	Distribution- Depreciation & Amortization Exp	DIST_PLANT	205	218,868	171,562	21,466	11,950	2,677	5,238	3,245	2,116	615
49	Gen, Com, & Int- Depreciation & Amortization Exp	PLANT	206	49,327	35,643	5,230	3,784	937	1,385	961	1,009	378
53	Test Year Total Depreciation & Amortization Exp			384,404	278,800	40,561	29,007	7,153	10,801	7,462	7,736	2,884

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Line. No.	(a) Summary Description	(b) Classification	(c) Allocation	(d) Total	(e) Residential	(f) Rate GS-1	(g) Rate GS-2	(h) Rate GS-3	(i) Rate ST	(j) Rate LT	(k) Rate XLT	(l) Rate XXLT
1	Test Year Lost and Unaccounted for (LAUF) Gas	ENERGY	102	12,709	8,962	1,690	1,601	456	-	-	-	-
5	Test Year Company Use	ENERGY	102	5,502	3,880	731	693	197	-	-	-	-
9	Test Year Property Taxes	PLANT	206	201,200	145,384	21,333	15,434	3,824	5,651	3,919	4,114	1,541
13	Test Year Federal, State & City Income Tax	PLANT	215	111,893	76,801	13,665	11,738	2,340	2,127	2,017	2,467	739
17	TCJA Amortization	PLANT	208	(2,042)	(1,457)	(219)	(164)	(41)	(58)	(41)	(45)	(17)
21		PLANT	208	-	-	-	-	-	-	-	-	-
25	Test Year Miscellaneous Taxes	ENERGY	112	5,119	3,677	572	434	95	116	90	100	34
29	Total Test Year Other Taxes			316,170	224,404	35,350	27,443	6,218	7,836	5,986	6,637	2,297
33	Total Test Year Expenses Excluding COGS & Company Use			1,025,616	754,138	108,742	76,003	18,034	25,266	17,870	18,773	6,790
34	Customer			437,023	337,541	43,891	26,333	5,866	9,614	6,399	5,552	1,827
35	Demand			555,438	390,309	61,021	47,534	11,608	15,539	11,378	13,120	4,928
36	Energy			33,155	26,288	3,830	2,137	560	113	93	100	34
37	Test Year Cost of Gas Sold (COGS)			737,588	520,137	98,061	92,931	26,459	-	-	-	-

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Line. No.	(a) Summary Description	(b) Classification	(c) Allocation	(d) Total	(e) Residential	(f) Rate GS-1	(g) Rate GS-2	(h) Rate GS-3	(i) Rate ST	(j) Rate LT	(k) Rate XLT	(l) Rate XXLT
1	Test Year Service Revenue Including Cost of Gas Sold			2,284,471	1,631,131	271,029	224,497	55,417	34,864	27,199	30,204	10,129
	Other Revenues											
2	Forfeited Discounts (Late Payment Charge)		111	6,322	4,514	750	621	153	96	75	84	28
3	Misc Service Rev (ASP)		102	1,356	956	180	171	49	-	-	-	-
4	Rev from Transmission of Gas of Others		204	13,448	8,154	1,582	1,508	401	535	421	597	250
5	Rent from Gas Property		204	290	176	34	32	9	12	9	13	5
6	Joint Commodities Mrkt Agrmt Rev		102	-	-	-	-	-	-	-	-	-
7	GCR related charges to Transport Customers		102	3,421	2,413	455	431	123	-	-	-	-
8	Gas Merchant-Buy/sell Contracts		1071	-	-	-	-	-	-	-	-	-
9	Rev from Storage Agrmts (GM, MCV & others)		1071	1,905	1,210	233	225	60	54	41	58	22
10	Administrative Customer Acctg charges for GCC		110	1,487	1,366	95	12	0	9	3	1	0
11	Interest on Cash Operating Accounts		209	358	266	37	25	6	9	6	7	3
12	Miscellaneous		111	81	58	10	8	2	1	1	1	0
13	Total Other Test Year Revenues			28,666	19,112	3,376	3,034	804	716	556	760	309
14	Total Test Year Revenues			2,313,137	1,650,243	274,406	227,531	56,220	35,580	27,755	30,965	10,438

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Functionalization Factors

	1	2	3	4	5
Description	**Source**	**Factor**	**Total System**	**Distribution**	**Transmission**	**Storage**
CWIP			322,877	83,734	70,152	168,990
	INTERNAL- Input Line 52	CWIP		25.9%	21.7%	52.3%
Distribution			1	1	0	0
	N/A	DIST		100.0%	0.0%	0.0%
O&M Expense			225,167	$ 166,855	$ 34,344	$ 23,968
	INTERNAL- Input Line 90	O&M		74.1%	15.3%	10.6%
O&M/Plant in Service		-	-	-	-	
	INTERNAL- 50/50 Weighting of O&M & PIS	O&M/PIS		68.6%	20.1%	11.3%
Plant in Service			13,763,449	$ 8,678,876	$ 3,446,129	$ 1,638,445
	INTERNAL- Input Line 44	PIS		63.1%	25.0%	11.9%
Rate Base			11,750,739	$ 6,489,133	$ 3,167,696	$ 2,093,910
	INTERNAL- Input Line 82	RB		55.2%	27.0%	17.8%
Total Revenue			2,284,471	1,429,647	534,788	320,036
	INTERNAL- Input Line 34	REV		62.6%	23.4%	14.0%
Storage			1	-	-	1
	N/A	STOR		0.0%	0.0%	100.0%
Taxable Income			654,045	358,737	177,317	133,009
	INTERNAL- Input- Summary & Expense	TAXABLEINC		53.6%	26.5%	19.9%
Transmission			1	-	1	-
	N/A	TRAN		0.0%	100.0%	0.0%

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Classification Factors

Description	Source	1 Factor	2 Total System	3 Customer	4 Demand	5 Energy
Demand	N/A	DEMAND	1	0 0%	1 100%	0 0%
Customer	N/A	CUST	1	1 100%	0 0%	0 0%
Energy/Commodity	N/A	ENERGY	1	0 0%	0 0%	1 100%
Total Plant (exc. General, Common & Intangible Plant)	INTERNAL-Total COSS, Page 3 of 16, Line 61	PLANT	13,763,449	5,388,971 39%	8,374,478 61%	- 0%
Transmission Plant	INTERNAL- Total COSS, Page 3 of 16, Line 17	TRAN_PLANT	3,323,679	- 0%	3,323,679 100%	- 0%
Distribution Plant	INTERNAL- Total COSS, Page 3 of 16, Line 57	DIST_PLANT	8,678,876	5,388,971 62.09%	3,289,905 37.91%	- 0%
Production Plant	INTERNAL- Total COSS, Page 3 of 16, Line 1	PROD_PLANT	122,449	- 0%	122,449 100%	- 0%
Storage Plant	INTERNAL- Total COSS, Page 3 of 16, Line 5	STOR_PLANT	1,638,445	- 0%	1,638,445 100%	- 0%
Distribution Mains	N/A	DIST_MAIN	-	- 0%	- 0%	- 0%
O&M Expense	INTERNAL- Total COSS, Page 7 of 16, Line 1	O&M (EXC. A&G)	225,167	118,281 53%	106,887 47%	- 0%
CWIP	INTERNAL- Total COSS, Page 4 of 16, Line 21	CWIP	322,877	51,993 16%	270,884 84%	- 0%

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Allocation Factors- Total System

Description	Source		Factor	Total System	Residential	Rate GS-1	Rate GS-2	Rate GS-3	Rate ST	Rate LT	Rate XLT	Rate XXLT
		1		2	3	4	5	6	7	8	9	10	11
Total Annual Throughput				307,735,810		157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
	WP-SMG-9	101				51.33%	9.73%	9.81%	2.66%	6.07%	6.16%	8.86%	5.37%
GCR Throughput				223,782,881		157,808,704	29,751,571	28,194,984	8,027,623	0	0	0	0
	WP-SMG-9	102				70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
Transportation Throughput				83,952,929		141,259	197,217	2,004,585	155,218	18,679,317	18,970,211	27,277,483	16,527,639
	WP-SMG-9	103				0.17%	0.23%	2.39%	0.18%	22.25%	22.60%	32.49%	19.69%
Average & Excess (Transmission)				1.0000		0.5728	0.1118	0.1049	0.0278	0.0528	0.0427	0.0606	0.0267
	WP-SMG-9	1041				57.28%	11.18%	10.49%	2.78%	5.28%	4.27%	6.06%	2.67%
Average & Excess (High Pressure)				1.0000		0.5609	0.1109	0.1035	0.0281	0.0520	0.0432	0.0701	0.0313
	WP-SMG-23	1051				56.09%	11.09%	10.35%	2.81%	5.20%	4.32%	7.01%	3.13%
Average & Excess (Non-High Pressure)				1.0000		0.6425	0.1202	0.1125	0.0265	0.0535	0.0338	0.0109	0.0000
	WP-SMG-23	1061				64.25%	12.02%	11.25%	2.65%	5.35%	3.38%	1.09%	0.00%
Average & Excess (50% Storage 50% Peak Month)				1.0000		0.6351	0.1226	0.1183	0.0316	0.0285	0.0216	0.0305	0.0117
	WP-SMG-23	1071				63.51%	12.26%	11.83%	3.16%	2.85%	2.16%	3.05%	1.17%
Weighted Customer				1,938,583		1,709,595	166,610	39,782	6,372	11,702	3,502	984	36
	WP-SMG-16	108				88.19%	8.59%	2.05%	0.33%	0.60%	0.18%	0.05%	0.00%
Average Number of Customers				1,846,892		1,709,595	119,353	15,633	539	1,282	359	128	3
	WP-SMG-16	109				92.57%	6.46%	0.85%	0.03%	0.07%	0.02%	0.01%	0.00%
Weighted/Average Customer				1.0000		0.9188	0.0641	0.0084	0.0003	0.0060	0.0018	0.0005	0.0000
	WP-SMG-16	110				91.88%	6.41%	0.84%	0.03%	0.60%	0.18%	0.05%	0.00%
Present Total Revenue (Including COGS)				2,284,471		1,631,131	271,029	224,497	55,417	34,864	27,199	30,204	10,129
	Exhibit A-16 (SAS-1), Sch F-2	111		100%		71.40%	11.86%	9.83%	2.43%	1.53%	1.19%	1.32%	0.44%
Present Delivery Revenue (Excluding COGS)				1,546,883		1,110,994	172,968	131,566	28,958	34,864	27,199	30,204	10,129
	Exhibit A-16 (SAS-1), Sch F-2	112		100%		71.82%	11.18%	8.51%	1.87%	2.25%	1.76%	1.95%	0.65%
Net Write Off				1.00		0.8905	0.1023	0.0066	0.0006	(0.0002)	0.0001	0.0000	0.0000
	WP-SMG-22	113				89.05%	10.23%	0.66%	0.06%	-0.02%	0.01%	0.00%	0.00%
BCC				1.00		0.0000	0.7751	0.1960	0.0068	0.0156	0.0047	0.0017	0.0000
	WP-SMG-25	114				0.00%	77.51%	19.60%	0.68%	1.56%	0.47%	0.17%	0.00%
CCC				1.00		0.9655	0.0341	0.0004	0.0000	0.0001	0.0000	0.0000	0.0000
	WP-SMG-25	115				96.55%	3.41%	0.04%	0.00%	0.01%	0.00%	0.00%	0.00%
Total Revenue				2,313,137		1,650,243	274,406	227,531	56,220	35,580	27,755	30,965	10,438
	INTERNAL- COSS PAGE 1, Line 3	201				71.34%	11.86%	9.84%	2.43%	1.54%	1.20%	1.34%	0.45%
Total Production Plant				122,449		86,350	16,279	15,428	4,393	-	-	-	-
	INTERNAL- Total COSS, Page 3 of 16, Line 1	202				70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
Total Transmission Plant				3,323,679		2,015,296	390,955	372,638	99,222	132,113	104,072	147,522	61,863
	INTERNAL- Total COSS, Page 3 of 16, Line 17	204				60.63%	11.76%	11.21%	2.99%	3.97%	3.13%	4.44%	1.86%
Total Distribution Plant				8,678,876		6,803,016	851,200	473,862	106,133	207,701	128,675	83,910	24,379
	INTERNAL- Total COSS, Page 3 of 16, Line 57	205				78.39%	9.81%	5.46%	1.22%	2.39%	1.48%	0.97%	0.28%
Total Plant in Service (excluding Gen, Com & Int)				13,763,449		9,945,275	1,459,305	1,055,780	261,568	386,570	268,102	281,414	105,435
	INTERNAL- COSS PAGE 3, Line 61	206				72.26%	10.60%	7.67%	1.90%	2.81%	1.95%	2.04%	0.77%
Total CWIP				322,877		215,559	37,191	32,439	8,467	9,592	7,067	9,053	3,510
	INTERNAL- COSS PAGE 4, Line 21	207				66.76%	11.52%	10.05%	2.62%	2.97%	2.19%	2.80%	1.09%
Rate Base				11,750,739		8,386,661	1,261,470	943,636	236,324	332,546	233,967	258,063	98,072
	INTERNAL- COSS PAGE 6, Line 25	208				71.37%	10.74%	8.03%	2.01%	2.83%	1.99%	2.20%	0.83%
Total O&M (excluding Admin & General)				240,186		184,862	23,858	14,361	3,374	5,367	3,567	3,516	1,281
	INTERNAL- COSS PAGE 7, Line 1,9,13	209				76.97%	9.93%	5.98%	1.40%	2.23%	1.49%	1.46%	0.53%
Total O&M Expense				240,186		184,862	23,858	14,361	3,374	5,367	3,567	3,516	1,281
	INTERNAL- COSS PAGE 7, Line 1,9,13	214				76.97%	9.93%	5.98%	1.40%	2.23%	1.49%	1.46%	0.53%
Pretax Net Operating Income				668,711		458,542	81,726	70,338	14,032	12,722	12,085	14,822	4,444
	INTERNAL- COSS (Multiple Pages & Lines)	215				68.57%	12.22%	10.52%	2.10%	1.90%	1.81%	2.22%	0.66%
Total Depreciation & Amortization				384,404		278,800	40,561	29,007	7,153	10,801	7,462	7,736	2,884
	INTERNAL- COSS PAGE 8, Line 53	216				72.53%	10.55%	7.55%	1.86%	2.81%	1.94%	2.01%	0.75%
Weighted HP and Non HP Plant				1.00		0.6341	0.1180	0.1132	0.0251	0.0500	0.0357	0.0204	0.0034
	WP-SMG-24	217				63.41%	11.80%	11.32%	2.51%	5.00%	3.57%	2.04%	0.34%

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Allocation Factors- Transmission System

		4	5	6	7	8	9	10	11
Factor	Transmission System	Residential	Rate GS-1	Rate GS-2	Rate GS-3	Rate ST	Rate LT	Rate XLT	Rate XXLT
	307,735,810	157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
101	100%	51.33%	9.73%	9.81%	2.66%	6.07%	6.16%	8.86%	5.37%
	223,782,881	157,808,704	29,751,571	28,194,984	8,027,623	0	0	0	0
102	100%	70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
	83,952,929	141,259	197,217	2,004,585	155,218	18,679,317	18,970,211	27,277,483	16,527,639
103	100%	0.17%	0.23%	2.39%	0.18%	22.25%	22.60%	32.49%	19.69%
	1.0000	**0.5728**	**0.1118**	**0.1049**	**0.0278**	**0.0528**	**0.0427**	**0.0606**	**0.0267**
1041	100%	57.28%	11.18%	10.49%	2.78%	5.28%	4.27%	6.06%	2.67%
	1.0000	0.5609	0.1109	0.1035	0.0281	0.0520	0.0432	0.0701	0.0313
1051	100%	56.09%	11.09%	10.35%	2.81%	5.20%	4.32%	7.01%	3.13%
	1.0000	0.6425	0.1202	0.1125	0.0265	0.0535	0.0338	0.0109	0.0000
1061	100%	64.25%	12.02%	11.25%	2.65%	5.35%	3.38%	1.09%	0.00%
	1.0000	**0.6351**	**0.1226**	**0.1183**	**0.0316**	**0.0285**	**0.0216**	**0.0305**	**0.0117**
1071	100%	63.51%	12.26%	11.83%	3.16%	2.85%	2.16%	3.05%	1.17%
	1,938,583	1,709,595	166,610	39,782	6,372	11,702	3,502	984	36
108	100%	88.19%	8.59%	2.05%	0.33%	0.60%	0.18%	0.05%	0.00%
	1,846,892	1,709,595	119,353	15,633	539	1,282	359	128	3
109	100%	92.57%	6.46%	0.85%	0.03%	0.07%	0.02%	0.01%	0.00%
	1.0000	0.9188	0.0641	0.0084	0.0003	0.0060	0.0018	0.0005	0.0000
110	100%	91.88%	6.41%	0.84%	0.03%	0.60%	0.18%	0.05%	0.00%
	534,788	340,760	68,465	66,764	16,621	11,224	10,299	14,969	5,686
111	100%	63.72%	12.80%	12.48%	3.11%	2.10%	1.93%	2.80%	1.06%
	350,109	210,527	43,912	43,496	9,996	11,224	10,299	14,969	5,686
112	100%	60.13%	12.54%	12.42%	2.86%	3.21%	2.94%	4.28%	1.62%
		0.8905	0.1023	0.0066	0.0006	(0.0002)	0.0001	0.0000	0.0000
113	100%	89.05%	10.23%	0.66%	0.06%	-0.02%	0.01%	0.00%	0.00%
		0.0000	0.7751	0.1960	0.0068	0.0156	0.0047	0.0017	0.0000
114	100%	0.00%	77.51%	19.60%	0.68%	1.56%	0.47%	0.17%	0.00%
		0.9655	0.0341	0.0004	0.0000	0.0001	0.0000	0.0000	0.0000
115	100%	96.55%	3.41%	0.04%	0.00%	0.01%	0.00%	0.00%	0.00%
	551,060	350,789	70,413	68,624	17,116	11,796	10,754	15,614	5,955
201	100%	63.66%	12.78%	12.45%	3.11%	2.14%	1.95%	2.83%	1.08%
	122,449	86,350	16,279	15,428	4,393	-	-	-	-
202	100%	70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
	3,323,679	2,015,296	390,955	372,638	99,222	132,113	104,072	147,522	61,863
204	100%	60.63%	11.76%	11.21%	2.99%	3.97%	3.13%	4.44%	1.86%
	8,678,876	6,803,016	851,200	473,862	106,133	207,701	128,675	83,910	24,379
205	100%	78.39%	9.81%	5.46%	1.22%	2.39%	1.48%	0.97%	0.28%
	3,446,129	2,101,645	407,234	388,066	103,614	132,113	104,072	147,522	61,863
206	100%	60.99%	11.82%	11.26%	3.01%	3.83%	3.02%	4.28%	1.80%
	70,152	42,593	8,261	7,873	2,098	2,766	2,179	3,088	1,295
207	100%	60.72%	11.78%	11.22%	2.99%	3.94%	3.11%	4.40%	1.85%
	3,167,696	1,927,785	373,778	356,255	94,987	122,984	96,917	137,390	57,599
208	100%	60.86%	11.80%	11.25%	3.00%	3.88%	3.06%	4.34%	1.82%
	34,344	20,824	4,040	3,850	1,025	1,365	1,075	1,524	639
209	100%	60.63%	11.76%	11.21%	2.99%	3.97%	3.13%	4.44%	1.86%
	34,344	20,824	4,040	3,850	1,025	1,365	1,075	1,524	639
214	100%	60.63%	11.76%	11.21%	2.99%	3.97%	3.13%	4.44%	1.86%
	179,149	106,363	23,723	24,255	4,862	4,632	5,106	7,607	2,600
215	100%	59.37%	13.24%	13.54%	2.71%	2.59%	2.85%	4.25%	1.45%
	89,207	54,133	10,500	10,008	2,666	3,528	2,780	3,940	1,652
216	100%	60.68%	11.77%	11.22%	2.99%	3.96%	3.12%	4.42%	1.85%
		0.6341	0.1180	0.1132	0.0251	0.0500	0.0357	0.0204	0.0034
217	100%	63.41%	11.80%	11.32%	2.51%	5.00%	3.57%	2.04%	0.34%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
Projected 12 Month Period: November 2025-October 2026
($000)

Case No.: U-21806
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Date: December 2024

Allocation Factors- Distribution System

		4	5	6	7	8	9	10	11
Factor	Distribution System	Residential	Rate GS-1	Rate GS-2	Rate GS-3	Rate ST	Rate LT	Rate XLT	Rate XXLT
	307,735,810	157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
101		51.33%	9.73%	9.81%	2.66%	6.07%	6.16%	8.86%	5.37%
	223,782,881	157,808,704	29,751,571	28,194,984	8,027,623	0	0	0	0
102		70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
	83,952,929	141,259	197,217	2,004,585	155,218	18,679,317	18,970,211	27,277,483	16,527,639
103		0.17%	0.23%	2.39%	0.18%	22.25%	22.60%	32.49%	19.69%
	1.0000	0.5728	0.1118	0.1049	0.0278	0.0528	0.0427	0.0606	0.0267
1041		57.28%	11.18%	10.49%	2.78%	5.28%	4.27%	6.06%	2.67%
	1.0000	0.5609	0.1109	0.1035	0.0281	0.0520	0.0432	0.0701	0.0313
1051		56.09%	11.09%	10.35%	2.81%	5.20%	4.32%	7.01%	3.13%
	1.0000	0.6425	0.1202	0.1125	0.0265	0.0535	0.0338	0.0109	0.0000
1061		64.25%	12.02%	11.25%	2.65%	5.35%	3.38%	1.09%	0.00%
	1.0000	0.6351	0.1226	0.1183	0.0316	0.0285	0.0216	0.0305	0.0117
1071		63.51%	12.26%	11.83%	3.16%	2.85%	2.16%	3.05%	1.17%
	1,938,583	1,709,595	166,610	39,782	6,372	11,702	3,502	984	36
108		88.19%	8.59%	2.05%	0.33%	0.60%	0.18%	0.05%	0.00%
	1,846,892	1,709,595	119,353	15,633	539	1,282	359	128	3
109		92.57%	6.46%	0.85%	0.03%	0.07%	0.02%	0.01%	0.00%
	1.0000	0.9188	0.0641	0.0084	0.0003	0.0060	0.0018	0.0005	0.0000
110		91.88%	6.41%	0.84%	0.03%	0.60%	0.18%	0.05%	0.00%
	1,429,647	1,080,576	161,071	116,661	28,346	18,918	12,697	9,029	2,349
111		75.58%	11.27%	8.16%	1.98%	1.32%	0.89%	0.63%	0.16%
	$ 964,543	$ 752,591	$ 99,236	$ 58,061	$ 11,662	$ 18,918	$ 12,697	$ 9,029	$ 2,349
112		78.03%	10.29%	6.02%	1.21%	1.96%	1.32%	0.94%	0.24%
	1.00	0.8905	0.1023	0.0066	0.0006	(0.0002)	0.0001	-	-
113		89.05%	10.23%	0.66%	0.06%	-0.02%	0.01%	0.00%	0.00%
	1.00	-	0.7751	0.1960	0.0068	0.0156	0.0047	0.0017	0.0000
114		0.00%	77.51%	19.60%	0.68%	1.56%	0.47%	0.17%	0.00%
	1.00	0.9655	0.0341	0.0004	0.0000	0.0001	-	-	-
115		96.55%	3.41%	0.04%	0.00%	0.01%	0.00%	0.00%	0.00%
	1,438,552	1,087,384	162,059	117,409	28,541	18,992	12,744	9,065	2,359
201		75.59%	11.27%	8.16%	1.98%	1.32%	0.89%	0.63%	0.16%
	122,449	86,350	16,279	15,428	4,393	-	-	-	-
202		70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
	3,323,679	2,015,296	390,955	372,638	99,222	132,113	104,072	147,522	61,863
204		60.63%	11.76%	11.21%	2.99%	3.97%	3.13%	4.44%	1.86%
	8,678,876	6,803,016	851,200	473,862	106,133	207,701	128,675	83,910	24,379
205		78.39%	9.81%	5.46%	1.22%	2.39%	1.48%	0.97%	0.28%
	8,678,876	6,803,016	851,200	473,862	106,133	207,701	128,675	83,910	24,379
206		78.39%	9.81%	5.46%	1.22%	2.39%	1.48%	0.97%	0.28%
	83,734	65,636	8,212	4,572	1,024	2,004	1,241	810	235
207		78.39%	9.81%	5.46%	1.22%	2.39%	1.48%	0.97%	0.28%
	6,489,133	5,116,057	629,040	338,161	74,328	155,118	95,866	62,443	18,120
208		78.84%	9.69%	5.21%	1.15%	2.39%	1.48%	0.96%	0.28%
	181,874	148,815	16,880	7,675	1,591	3,318	1,975	1,261	361
209		81.82%	9.28%	4.22%	0.87%	1.82%	1.09%	0.69%	0.20%
	181,874 -	148,815	16,880	7,675	1,591	3,318	1,975	1,261	361
214		81.82%	9.28%	4.22%	0.87%	1.82%	1.09%	0.69%	0.20%
	355,353	266,652	40,214	27,682	4,976	6,126	4,863	3,957	883
215		75.04%	11.32%	7.79%	1.40%	1.72%	1.37%	1.11%	0.25%
	249,972	195,943	24,517	13,648	3,057	5,982	3,706	2,417	702
216		78.39%	9.81%	5.46%	1.22%	2.39%	1.48%	0.97%	0.28%
	1.0000	0.6341	0.1180	0.1132	0.0251	0.0500	0.0357	0.0204	0.0034
217		63.41%	11.80%	11.32%	2.51%	5.00%	3.57%	2.04%	0.34%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
Projected 12 Month Period: November 2025-October 2026
($000)

Case No.: U-21806
Exhibit No.: A-54 (SMG-3)
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Witness: SMGeller
Date: December 2024

Allocation Factors- Storage System

			4	5	6	7	8	9	10	11
Factor	Storage System		Residential	Rate GS-1	Rate GS-2	Rate GS-3	Rate ST	Rate LT	Rate XLT	Rate XXLT
	307,735,810		157,949,963	29,948,787	30,199,569	8,182,841	18,679,317	18,970,211	27,277,483	16,527,639
101	100%		51.33%	9.73%	9.81%	2.66%	6.07%	6.16%	8.86%	5.37%
	223,782,881		157,808,704	29,751,571	28,194,984	8,027,623	0	0	0	0
102	100%		70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
	83,952,929		141,259	197,217	2,004,585	155,218	18,679,317	18,970,211	27,277,483	16,527,639
103	100%		0.17%	0.23%	2.39%	0.18%	22.25%	22.60%	32.49%	19.69%
	1.0000		**0.5728**	**0.1118**	**0.1049**	**0.0278**	**0.0528**	**0.0427**	**0.0606**	**0.0267**
1041	100%		57.28%	11.18%	10.49%	2.78%	5.28%	4.27%	6.06%	2.67%
	1.0000		0.5609	0.1109	0.1035	0.0281	0.0520	0.0432	0.0701	0.0313
1051	100%		56.09%	11.09%	10.35%	2.81%	5.20%	4.32%	7.01%	3.13%
	1.0000		0.6425	0.1202	0.1125	0.0265	0.0535	0.0338	0.0109	0.0000
1061	100%		64.25%	12.02%	11.25%	2.65%	5.35%	3.38%	1.09%	0.00%
	1.0000		**0.6351**	**0.1226**	**0.1183**	**0.0316**	**0.0285**	**0.0216**	**0.0305**	**0.0117**
1071	100%		63.51%	12.26%	11.83%	3.16%	2.85%	2.16%	3.05%	1.17%
	1,938,583		1,709,595	166,610	39,782	6,372	11,702	3,502	984	36
108	100%		88.19%	8.59%	2.05%	0.33%	0.60%	0.18%	0.05%	0.00%
	1,846,892		1,709,595	119,353	15,633	539	1,282	359	128	3
109	100%		92.57%	6.46%	0.85%	0.03%	0.07%	0.02%	0.01%	0.00%
	1.0000		0.9188	0.0641	0.0084	0.0003	0.0060	0.0018	0.0005	0.0000
110	100%		91.88%	6.41%	0.84%	0.03%	0.60%	0.18%	0.05%	0.00%
	320,036		209,795	41,494	41,072	10,450	4,721	4,203	6,207	2,094
111	100%		65.55%	12.97%	12.83%	3.27%	1.48%	1.31%	1.94%	0.65%
	$ 232,231	$	147,876 $	29,820 $	30,009 $	7,300 $	4,721 $	4,203 $	6,207 $	2,094
112	100%		63.68%	12.84%	12.92%	3.14%	2.03%	1.81%	2.67%	0.90%
	-	-	0.89	0.10	0.01	0.00	(0.00)	0.00	-	-
113	100%		89.05%	10.23%	0.66%	0.06%	-0.02%	0.01%	0.00%	0.00%
	-	-	-	0.78	0.20	0.01	0.02	0.00	0.00	0.00
114	100%		0.00%	77.51%	19.60%	0.68%	1.56%	0.47%	0.17%	0.00%
	-	-	0.97	0.03	0.00	0.00	0.00	-	-	-
115	100%		96.55%	3.41%	0.04%	0.00%	0.01%	0.00%	0.00%	0.00%
	323,525		212,070	41,934	41,498	10,564	4,792	4,258	6,286	2,123
201	100%		65.55%	12.96%	12.83%	3.27%	1.48%	1.32%	1.94%	0.66%
	122,449		86,350	16,279	15,428	4,393	-	-	-	-
202	100%		70.52%	13.29%	12.60%	3.59%	0.00%	0.00%	0.00%	0.00%
	3,323,679		2,015,296	390,955	372,638	99,222	132,113	104,072	147,522	61,863
204	100%		60.63%	11.76%	11.21%	2.99%	3.97%	3.13%	4.44%	1.86%
	8,678,876		6,803,016	851,200	473,862	106,133	207,701	128,675	83,910	24,379
205	100%		78.39%	9.81%	5.46%	1.22%	2.39%	1.48%	0.97%	0.28%
	1,638,445		1,040,615	200,871	193,852	51,822	46,756	35,355	49,981	19,193
206	100%		63.51%	12.26%	11.83%	3.16%	2.85%	2.16%	3.05%	1.17%
	168,990		107,330	20,718	19,994	5,345	4,822	3,647	5,155	1,980
207	100%		63.51%	12.26%	11.83%	3.16%	2.85%	2.16%	3.05%	1.17%
	2,093,910		1,342,819	258,653	249,220	67,009	54,444	41,184	58,229	22,353
208	100%		64.13%	12.35%	11.90%	3.20%	2.60%	1.97%	2.78%	1.07%
	23,968		15,223	2,938	2,836	758	684	517	731	281
209	100%		63.51%	12.26%	11.83%	3.16%	2.85%	2.16%	3.05%	1.17%
	23,968	-	15,223	2,938	2,836	758	684	517	731	281
214	100%		63.51%	12.26%	11.83%	3.16%	2.85%	2.16%	3.05%	1.17%
	134,210		85,527	17,789	18,401	4,194	1,963	2,117	3,258	962
215	100%		63.73%	13.25%	13.71%	3.13%	1.46%	1.58%	2.43%	0.72%
	45,225		28,723	5,544	5,351	1,430	1,291	976	1,380	530
216	100%		63.51%	12.26%	11.83%	3.16%	2.85%	2.16%	3.05%	1.17%
	-	-	0.6341	0.1180	0.1132	0.0251	0.0500	0.0357	0.0204	0.0034
217	100%		63.41%	11.80%	11.32%	2.51%	5.00%	3.57%	2.04%	0.34%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Allocation of Home Products Credit ($000)

Case No.: U-21806
Exhibit No.: A-55 (SMG-4)
Page: 1 of 1
Witness: SMGeller
Date: December 2024

Line No	Description	Total Gas	Source
1	Home Products Credit	**$ (27,500)**	Settlement in case U-21490

Line No	Description	Alloc	Total	Residential	Rate GS-1	Rate GS-2	Rate GS-3	Rate ST	Rate LT	Rate XLT	Rate XXLT
			(a)	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
2	**Home Products Credit**										
3	1/ Total O&M (excluding Admin & General)	209	100%	77.08%	9.90%	6.06%	1.33%	2.13%	1.52%	1.55%	0.45%
4	Allocation of Home Products Credit		**$ (27,500)**	**$(21,195.94)**	**$ (2,722.51)**	**$ (1,665.81)**	**$ (364.72)**	**$ (584.47)**	**$ (417.68)**	**$ (426.24)**	**$ (122.64)**

Source:
1/ Exhibit A-16 (SMG-2), Schedule F-1.1, Page 13

> double-counting average demand understates the residential cost of service while overstating the cost of service of more efficient gas users…. Based on the above, we find that the Company's proposed A&E methodology is more reflective of an accurate representation of PECO's mains distribution system.[8]

Similarly, the Minnesota Public Utilities Commission also approved Minnesota Power's proposal to replace the A&P method with A&E in its 2021 rate case citing the issue of double counting:

> Minnesota Power articulates reasonable grounds – based in concerns for equity, efficiency, and cost causation – for favoring the Average & Excess classification method over the Peak & Average method. Both methods recognize that average demand and peak demand warrant consideration. The choice to use peak demand in excess of average demand mitigates the double-counting problem associated with the Peak & Average method.[9]

Q HAS CONSUMERS PREPARED A CCOSS USING THE A&E METHODOLOGY?

A Yes. As previously discussed, Version 3 of the CCOSS prepared by Consumers appropriately utilizes the A&E method in place of the A&P method to allocate the costs of transmission, high pressure mains, non-high pressure mains, and storage.[10]

Q HAVE YOU CORRECTED THE A&E ALLOCATION FACTORS IN CONSUMERS' VERSION 3 CCOSS?

A Yes. I corrected the A&E allocation factors Consumers calculated by utilizing each class's NCP demand in place of the PDD. The class NCP was derived using each class's maximum monthly throughput instead of the PDD. Thus, excess demand is

[8] *Id.* at 229-230.

[9] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-21-355, Findings of Fact, Conclusions, and Order at 54 (Feb. 28, 2023).

[10] Direct Testimony of Yong F. Keyes at 3.

the difference between each class's maximum monthly throughput and its average demand. The revised NCP A&E allocators are shown in **Table 1**.

Table 1
Consumers' CCOSS Version 3
Using ABATE's A&E Allocation Factor Refinement
Using Peak Design Day and Noncoincident Peak Demand

Customer Class	Allocator 1041		Allocator 1051		Allocator 1061		Allocator 1071	
	PDD	NCP	PDD	NCP	PDD	NCP	PDD	NCP
Residential	58.86%	55.23%	58.24%	54.48%	64.61%	61.83%	65.01%	62.54%
Rate GS-1	13.42%	13.43%	13.36%	13.35%	14.06%	14.36%	13.83%	13.84%
Rate GS-2	11.28%	10.97%	11.23%	10.89%	11.81%	11.72%	12.12%	11.90%
Rate GS-3	2.45%	2.36%	2.45%	2.34%	2.45%	2.48%	2.98%	2.92%
Rate ST	3.60%	4.84%	3.59%	4.81%	3.67%	5.04%	1.72%	2.56%
Rate LT	3.00%	4.35%	3.07%	4.46%	2.31%	3.26%	1.29%	2.20%
Rate XLT	4.93%	5.99%	5.35%	6.51%	1.09%	1.31%	2.23%	2.95%
Rate XXLT	2.45%	2.84%	2.70%	3.14%	0.00%	0.00%	0.83%	1.09%
Total	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Q WHY ARE YOU RECOMMENDING A REVISED VERSION 3 CCOSS?

A I am recommending that the Commission adopt ABATE's revised Version 3 CCOSS to better reflect cost-causation principles relative to Consumers' proposed Version 2 and Version 3 CCOSSs. First, as previously discussed, the A&E method is an improvement over the A&P method utilized in Version 2 because it appropriately balances the two components of a class's average and peak demands without double-counting. The average component included in the A&E method is mathematically and functionally identical to that included in the A&P method, and subsequently, they provide the same measure of annual throughput for each class and recognize that the gas distribution system is partially planned to serve customers in each and every day

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas Cost-of-Service Study
Settlement Agreement FERC Account 378 Study

Case No.: U-21806
Exhibit No.: A-57 (SMG-6)
Page: 1 of 1
Witness: SMGeller
Date: December 2024

Line	(a) Answer	(b) Cost Type		(c) Total Number of Stations	(d) Precent of stations	(e) Total book value	(f) Percent of book value
1	1	Measuring and Regulator Stations				$ 254,576,225	86.07%
2	2	All Other Costs - Huron Compressor Station				$ 14,335	0.005%
3	2	All Other Costs - Odorization				$ 41,200,505	13.93%
4			TOTAL			$ 295,791,065	100%
		Station Type					
5	3a	Reg stations Serving HP distribution systems		23	3.55%	$ 21,710,634	9.89%
6	3b	Reg stations served by HP and not serving a downstream HP system		587	90.59%	$ 195,057,647	88.89%
7	3c	Reg stations exclusively with an SP outlet, served by a MP outlet		38	5.86%	$ 2,676,313	1.22%
8			TOTAL	648	100%	$ 219,444,593	100%

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual & Projected Regulatory Compliance O&M Expenses

For the Years 2023, 2024, 2025 and Test Year 12 Months Ending October 31, 2026

($000)

Case No.: U-21806
Exhibit No.: A-58 (MPG-1)
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Witness: MPGriffin
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Line No.		Description	(a) 2023 Actual	(b) 2024 Projected	(c) 2025 Projected	(d) Projected 12-Mos Ending Oct 31, 2026
1		**MAOP Transmission**	**1,187**	**1,898**	**2,361**	**2,370**
	11%	Labor	130	208	258	259
	5%	Material	58	92	115	115
	82%	Contractor	977	1,562	1,943	1,950
	2%	Non-Labor Overheads	18	30	37	37
	0%	Non-Labor Other	4	7	8	9
2		**Corrosion Control - Transmission**	**947**	**1,505**	**1,955**	**2,210**
	25%	Labor	235	373	485	548
	3%	Material	26	41	53	60
	65%	Contractor	615	978	1,270	1,435
	8%	Non-Labor Overheads	71	113	147	166
	0%	Non-Labor Other	0	1	1	1
3		**Pipeline Integrity - TOD**	**812**	**1,059**	**1,085**	**1,420**
	7%	Labor	58	75	77	101
	8%	Material	62	81	83	109
	83%	Contractor	671	875	897	1,174
	1%	Non-Labor Overheads	8	11	11	15
	2%	Non-Labor Other	13	16	17	22
4		**Pipeline Integrity - Transmission**	**17,089**	**22,275**	**23,110**	**17,128**
	11%	Labor	1,950	2,542	2,638	1,955
	1%	Material	245	320	332	246
	83%	Contractor	14,178	18,481	19,174	14,211
	4%	Non-Labor Overheads	614	801	831	616
	1%	Non-Labor Other	101	131	136	101
5		**Total Regulatory Compliance O&M Expenses**	**$ 20,034**	**$ 26,737**	**$ 28,512**	**$ 23,129**
		Labor	2,373	3,199	3,458	2,863
		Material	391	534	583	530
		Contractor	16,440	21,895	23,283	18,770
		Non-Labor Overheads	712	954	1,025	833
		Non-Labor Other	118	155	162	132

*** Notes:
Percentage breakdown for cost elements is based on 2023 actual
2026 Test Year is based on a monthly cash flow of 2025 and 2026

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual & Projected Regulatory Compliance O&M Expenses

Summary of O&M Expenses Projected Using Inflation

For the Years 2023, 2024, 2025 and Test Year 12 Months Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-58 (MPG-1)
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($000)

Line No.	Description	(a) 2023 Actual	(b) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2023	(c) Merit & Inflation 12 Mos Ending Dec 31, 2024	(d) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	(e) Merit & Inflation 12 Mos Ending Dec 31, 2025	(f) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	(g) Merit & Inflation 10 Mos Ending Oct 31, 2026	(h) Other Adjustments	(i) Projected O&M 12 Mos Ending Oct 31, 2026
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	**MAOP Transmission**	**1,187**	**1,136**	**-**	**1,136**	**-**	**1,136**	**-**	**1,183**	**2,370**
	Labor	130	79	-	79	-	79	-	129	259
	Materials	58	58	-	58	-	58	-	58	115
	Contractor	977	977	-	977	-	977	-	974	1,950
	Non-Labor Overhead	18	18	-	18	-	18	-	18	37
	Non-Labor Other	4	4	-	4	-	4	-	4	9
2	**Corrosion Control - Transmission**	**947**	**730**	**-**	**730**	**-**	**730**	**-**	**1,263**	**2,210**
	Labor	235	18	-	18	-	18	-	313	548
	Materials	26	26	-	26	-	26	-	34	60
	Contractor	615	615	-	615	-	615	-	820	1,435
	Non-Labor Overhead	71	71	-	71	-	71	-	95	166
	Non-Labor Other	0	0	-	0	-	0	-	1	1
3	**Pipeline Integrity - Distribution**	**812**	**784**	**-**	**784**	**-**	**784**	**-**	**609**	**1,420**
	Labor	58	30	-	30	-	30	-	43	101
	Materials	62	62	-	62	-	62	-	47	109
	Contractor	671	671	-	671	-	671	-	503	1,174
	Non-Labor Overhead	8	8	-	8	-	8	-	6	15
	Non-Labor Other	13	13	-	13	-	13	-	9	22
4	**Pipeline Integrity - Transmission**	**17,089**	**15,654**	**-**	**15,654**	**-**	**15,654**	**-**	**40**	**17,128**
	Labor	1,950	515	-	515	-	515	-	5	1,955
	Materials	245	245	-	245	-	245	-	1	246
	Contractor	14,178	14,178	-	14,178	-	14,178	-	33	14,211
	Non-Labor Overhead	614	614	-	614	-	614	-	1	616
	Non-Labor Other	101	101	-	101	-	101	-	0	101
5	**Total Regulatory Compliance O&M Expenses**	**$ 20,034**	**$ 18,304**	**$ -**	**$ 18,304**	**$ -**	**$ 18,304**	**$ -**	**$ 3,095**	**$ 23,129**
	Labor	2,373	643	-	643	-	643	-	490	2,863
	Materials	391	391	-	391	-	391	-	139	530
	Contractor	16,440	16,440	-	16,440	-	16,440	-	2,330	18,770
	Non-Labor Overhead	712	712	-	712	-	712	-	121	833
	Non-Labor Other	118	118	-	118	-	118	-	14	132

Notes

		Base Labor is all labor cost elements less OM&C & Indirect Labor		
		12-Mo Ending 2024	**12-Mo Ending 2025**	**10-Mo Ending 2026**
6	Annual merit and inflation rates per WP-HLR-44			
	Annual inflation rates	3.2%	2.4%	2.5%
	Number of months in the period	12	12	10
	Pro-rated inflation rate	3.2%	2.4%	2.1%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Historical Actual Regulatory Compliance Expenses
($000)

Case No.: U-21806
Exhibit No.: A-58 (MPG-1)
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Date: December 2024

Line No.	Description	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**MAOP Transmission**	**3,813**	**2,765**	**455**	**1,004**	**1,311**	**1,187**
	Labor	64	92	7	133	118	130
	Material	245	69	-	853	288	58
	Contractor	3,499	2,588	410	6	432	977
	Non-Labor Overheads	1	10	3	11	4	18
	Non-Labor Other	4	6	35	(0)	469	4
2	**Corrosion Control - Transmission**	**551**	**34**	**638**	**1,076**	**1,978**	**947**
	Labor	7	5	12	77	117	235
	Material	12	-	249	4	14	26
	Contractor	539	28	375	969	1,674	615
	Non-Labor Overheads	4	1	2	23	36	71
	Non-Labor Other	(12)	-	-	4	137	0
3	**Pipeline Integrity - Distribution**	**812**	**481**	**2,980**	**839**	**973**	**812**
	Labor	48	32	93	26	28	58
	Material	(20)	13	211	53	51	62
	Contractor	756	427	2,651	753	886	671
	Non-Labor Overheads	19	7	17	4	4	8
	Non-Labor Other	8	1	8	2	3	13
4	**Pipeline Integrity - Transmission**	**32,992**	**21,120**	**21,344**	**26,894**	**19,370**	**17,089**
	Labor	1,789	838	1,242	1,682	1,084	1,950
	Material	407	711	821	347	550	245
	Contractor	29,758	19,306	18,891	24,400	14,969	14,178
	Non-Labor Overheads	366	287	300	489	404	614
	Non-Labor Other	672	(21)	90	(25)	2,363	101
5	**Total Regulatory Compliance O&M Expenses**	**$ 38,168**	**$ 24,400**	**$ 25,416**	**$ 29,812**	**$ 23,631**	**$ 20,034**
	Labor	1,908	966	1,353	1,919	1,348	2,373
	Material	644	793	1,281	1,256	902	391
	Contractor	34,553	22,350	22,327	26,129	17,960	16,440
	Non-Labor Overheads	391	305	322	528	449	712
	Non-Labor Other	672	(13)	133	(20)	2,972	118

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Gas Transmission Capital Expenditures
Asset Relocation Transmission Program
($000)

Case No.: U-21806
Exhibit No.: A-59 (MPG-3)
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Witness: MPGriffin
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)	
		Historical Year	Projected Bridge Year			Projected Test Year	
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	Source
1	**Asset Relocation**	**6,168**	**17,389**	**19,138**	**36,527**	**24,726**	WP-MPG-1
3%	Labor	171	462	508	970	656	
24%	Capitalized Engineering/Supv	1,487	4,165	4,584	8,749	5,922	
22%	Materials	989	3,767	4,146	7,914	5,357	
41%	Contractor	2,889	7,168	7,889	15,058	10,193	
0%	Non-Labor Overhead	18	36	40	77	52	
10%	Non-Labor Other	614	1,790	1,971	3,761	2,546	
2	**Total Capital**	**6,168**	**17,389**	**19,138**	**36,527**	**24,726**	
	Labor	171	462	508	970	656	
	Capitalized Engineering/Supv	1,487	4,165	4,584	8,749	5,922	
	Materials	989	3,767	4,146	7,914	5,357	
	Contractor	2,889	7,168	7,889	15,058	10,193	
	Non-Labor Overhead	18	36	40	77	52	
	Non-Labor Other	614	1,790	1,971	3,761	2,546	

		Projected			
		10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
3	**Asset Relocation**	**15,150**	**21,377**	**24,726**	**61,253**
3%	Labor	402	567	656	1,626
24%	Capitalized Engineering/Supv	3,629	5,120	5,922	14,671
22%	Materials	3,282	4,631	5,357	13,270
41%	Contractor	6,245	8,812	10,193	25,250
0%	Non-Labor Overhead	32	45	52	129
10%	Non-Labor Other	1,560	2,201	2,546	6,307
4	**Total Capital**	**15,150**	**21,377**	**24,726**	**61,253**
	Labor	402	567	656	1,626
	Capitalized Engineering/Supv	3,629	5,120	5,922	14,671
	Materials	3,282	4,631	5,357	13,270
	Contractor	6,245	8,812	10,193	25,250
	Non-Labor Overhead	32	45	52	129
	Non-Labor Other	1,560	2,201	2,546	6,307

Unless noted otherwise, capital "other" costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).

This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop these cost projections.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Gas Transmission Capital Expenditures
Asset Relocation Transmission Program
($000)

Case No.: U-21806
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Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Year 12 Mos Ending 12/31/2024	(d) Projected Bridge Year 10 Mos Ending 10/31/2025	(e) Projected Bridge Year 22 Mos Ending 10/31/2025 [Col. (c) + (d)]	(f) Projected Test Year 12 Mos Ending 10/31/2026
	Projects Over $5 Million					
1	**Asset Relocation**					
2	KZO-1200A Wetland BR017 Ln Lwrng	94	84	30	114	7,264
3	KZO-1200A Townline Rd Ln Lwrng	-	84	43	127	10,513
4	SAG-100B Sleepy Hollow Re-route	1,742	13,238	146	13,384	98
5	OVS-1100 Rabbit River Ln Lwrng	179	121	6,993	7,114	450
	Projects Under $5 Million					
6	Asset Relocation	4,152	3,862	11,926	15,787	6,400
7	**Total Capital**	6,168	17,389	19,138	36,527	24,726

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Gas Transmission Capital Expenditures
Regulatory Compliance Program
($000)

Case No.: U-21806
Exhibit No.: A-60 (MPG-4)
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	(a)	(b)	(c)	(d)	(e)	(f)	
		Historical Year	Projected Bridge Year			Projected Test Year	
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	Source
1	**Pipeline Integrity - (Transmission)**	**16,148**	**13,381**	**10,504**	**23,885**	**5,144**	WP-MPG-12, 14, 16, 18
3%	Labor	418	462	363	825	178	
24%	Capitalized Engineering/Supv	4,002	3,249	2,550	5,799	1,249	
4%	Materials	584	545	428	972	209	
59%	Contractor	9,699	7,898	6,200	14,099	3,036	
1%	Non-Labor Overhead	76	99	78	177	38	
8%	Non-Labor Other	1,369	1,127	885	2,012	433	
2	**Pipeline Integrity- Transmission Operated by Distribution (TOD)**	**9,274**	**6,119**	**5,593**	**11,713**	**9,998**	WP-MPG-13, 15, 17, 19
8%	Labor	784	504	461	965	824	
25%	Capitalized Engineering/Supv	2,381	1,557	1,423	2,980	2,544	
11%	Materials	845	693	633	1,326	1,132	
37%	Contractor	3,541	2,246	2,053	4,299	3,670	
1%	Non-Labor Overhead	77	45	41	86	74	
18%	Non-Labor Other	1,645	1,074	982	2,056	1,755	
3	**Cathodic Compression, Storage & Pipeline**	**5,931**	**6,526**	**5,779**	**12,305**	**6,649**	WP-MPG-11
5%	Labor	341	331	293	625	338	
22%	Capitalized Engineering/Supv	1,381	1,464	1,296	2,760	1,492	
5%	Materials	374	311	276	587	317	
58%	Contractor	3,272	3,813	3,377	7,190	3,885	
0%	Non-Labor Overhead	32	29	25	54	29	
9%	Non-Labor Other	531	577	511	1,088	588	
4	**MAOP Compliance Pipeline**	**4,786**	**51**	**2,409**	**2,460**	**3,016**	WP-MPG-2
4%	Labor	146	2	92	94	115	
25%	Capitalized Engineering/Supv	1,193	13	600	613	751	
10%	Materials	740	5	248	253	311	
52%	Contractor	2,312	27	1,252	1,278	1,567	
0%	Non-Labor Overhead	13	0	10	10	12	
9%	Non-Labor Other	383	4	208	212	260	
5	**Total Capital**	**36,139**	**26,078**	**24,285**	**50,362**	**24,807**	
	Labor	1,689	1,300	1,209	2,509	1,455	
	Capitalized Engineering/Supv	8,957	6,283	5,870	12,152	6,036	
	Materials	2,543	1,554	1,585	3,139	1,970	
	Contractor	18,824	13,984	12,881	26,865	12,158	
	Non-Labor Overhead	198	173	154	328	153	
	Non-Labor Other	3,928	2,783	2,585	5,368	3,036	

Unless noted otherwise, capital "other" costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).

This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop these cost projections.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Gas Transmission Capital Expenditures
Regulatory Compliance Program
($000)

Case No.: U-21806
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	(a)	(b)	(c)	(d)	(e)
		Projected			
		10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
6	**Pipeline Integrity - (Transmission)**	**15,699**	**8,185**	**5,144**	**29,028**
3%	Labor	542	283	178	1,003
24%	Capitalized Engineering/Supv	3,812	1,987	1,249	7,048
4%	Materials	639	333	209	1,182
59%	Contractor	9,267	4,832	3,036	17,135
1%	Non-Labor Overhead	117	61	38	216
8%	Non-Labor Other	1,322	689	433	2,445
7	**Pipeline Integrity- Transmission Op**	**5,593**	**6,119**	**9,998**	**21,711**
8%	Labor	461	504	824	1,789
25%	Capitalized Engineering/Supv	1,423	1,557	2,544	5,524
11%	Materials	633	693	1,132	2,459
37%	Contractor	2,053	2,246	3,670	7,968
1%	Non-Labor Overhead	41	45	74	160
18%	Non-Labor Other	982	1,074	1,755	3,811
8	**Cathodic Compression, Storage & I**	**5,992**	**6,312**	**6,649**	**18,954**
5%	Labor	304	321	338	962
22%	Capitalized Engineering/Supv	1,344	1,416	1,492	4,252
5%	Materials	286	301	317	904
58%	Contractor	3,501	3,688	3,885	11,075
0%	Non-Labor Overhead	26	28	29	84
9%	Non-Labor Other	530	558	588	1,676
9	**MAOP Compliance Pipeline**	**(109)**	**2,570**	**3,016**	**5,476**
4%	Labor	(4)	98	115	210
25%	Capitalized Engineering/Supv	(27)	640	751	1,364
10%	Materials	(11)	265	311	564
52%	Contractor	(57)	1,335	1,567	2,845
0%	Non-Labor Overhead	(0)	10	12	22
9%	Non-Labor Other	(9)	221	260	472
10	**Total Capital**	**27,176**	**23,187**	**24,807**	**75,170**
	Labor	1,303	1,206	1,455	3,964
	Capitalized Engineering/Supv	6,552	5,600	6,036	18,188
	Materials	1,547	1,592	1,970	5,109
	Contractor	14,765	12,101	12,158	39,023
	Non-Labor Overhead	184	144	153	481
	Non-Labor Other	2,825	2,543	3,036	8,404

This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Gas Transmission Capital Expenditures
Regulatory Compliance Program
($000)

Case No.: U-21806
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Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Year 12 Mos Ending 12/31/2024	(d) Projected Bridge Year 10 Mos Ending 10/31/2025	(e) Projected Bridge Year 22 Mos Ending 10/31/2025 [Col. (c) + (d)]	(f) Projected Test Year 12 Mos Ending 10/31/2026
	Projects Over $5 Million					
1	**Pipeline Integrity - (Transmission)**					
2	None identified	-	-	-	-	-
3	**Pipeline Integrity- Transmission Operated by Distribution (TOD)**					
4	None identified	-	-	-	-	-
5	**Cathodic Compression, Storage & Pipeline**					
6	None identified	-	-	-	-	-
7	**MAOP Compliance Pipeline**					
8	None identified	-	-	-	-	-
	Projects Under $5 Million					
9	Pipeline Integrity - (Transmission)	16,148	13,381	10,504	23,885	5,144
10	Pipeline Integrity- Transmission Operate	9,274	6,119	5,593	11,713	9,998
11	Cathodic Compression, Storage & Pipe	5,931	6,526	5,779	12,305	6,649
12	MAOP Compliance Pipeline	4,786	51	2,409	2,460	3,016
13	**Total Capital**	36,139	26,078	24,285	50,362	24,807

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Transmission and Distribution Capital Expenditures
Capacity/Deliverability Program
($000)

Case No.: U-21806
Exhibit No.: A-61 (MPG-5) **Revised**
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Witness: MPGriffin
Date: December 2024

Line No	Description	Historical Year 12 Mos Ended 12/31/2023	Projected Bridge Year 12 Mos Ending 12/31/2024	Projected Bridge Year 10 Mos Ending 10/31/2025	Projected Bridge Year 22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026	Source
	(a)	(b)	(c)	(d)	(e)	(f)	
1	**Transmission Enhancements for Deliverability & Integrity ("TED-I")**	**216,361**	**146,790**	**20,192**	**166,982**	**19,145**	Exhibit A-62 (MPG-6)
	Labor	4,591	3,708	995	4,703	1,029	
	Capitalized Engineering/Supv	3,840	209	2,941	3,150	4,135	
	Materials	10,204	3,070	494	3,564	662	
	Contractor	172,830	129,961	13,225	143,186	10,523	
	Non-Labor Overhead	607	430	74	505	26	
	Non-Labor Other	24,289	9,413	2,461	11,874	2,770	
2	**Misc Transmission & Compression**	**257**	**22**	**0**	**22**	**0**	
5%	Labor	7	1	0	1	0	
26%	Capitalized Engineering/Supv	69	6	0	6	0	
-1%	Materials	(4)	(0)	0	(0)	0	
49%	Contractor	131	11	0	11	0	
0%	Non-Labor Overhead	0	0	0	0	0	
20%	Non-Labor Other	55	4	0	4	0	
3	**Deliverability Base Field Measurement**	**5,319**	**6,774**	**10,255**	**17,029**	**19,890**	WP-MPG-3
5%	Labor	266	312	473	785	917	
24%	Capitalized Engineering/Supv	1,339	1,624	2,458	4,082	4,768	
25%	Materials	1,110	1,684	2,549	4,233	4,945	
71%	Contractor	4,161	4,835	7,319	12,154	14,196	
0%	Non-Labor Overhead	26	32	48	79	93	
-25%	Non-Labor Other	(1,585)	(1,713)	(2,593)	(4,306)	(5,029)	
4	**Deliverability Base Pipeline**	**18,757**	**18,014**	**19,120**	**37,134**	**25,073**	WP-MPG-4
8%	Labor	1,560	1,470	1,561	3,031	2,047	
23%	Capitalized Engineering/Supv	4,428	4,216	4,475	8,690	5,868	
13%	Materials	2,152	2,366	2,511	4,878	3,293	
43%	Contractor	8,422	7,836	8,317	16,153	10,906	
1%	Non-Labor Overhead	292	257	272	529	357	
10%	Non-Labor Other	1,902	1,869	1,984	3,853	2,601	
5	**Regulator Stations - Distribution**	**36,262**	**45,690**	**36,039**	**81,729**	**47,274**	WP-MPG-5
10%	Labor	3,565	4,672	3,685	8,356	4,834	
25%	Capitalized Engineering/Supv	9,028	11,221	8,851	20,073	11,610	
11%	Materials	3,270	5,001	3,944	8,945	5,174	
34%	Contractor	13,217	15,691	12,377	28,068	16,235	
1%	Non-Labor Overhead	374	466	367	833	482	
19%	Non-Labor Other	6,808	8,640	6,815	15,454	8,939	
6	**T&S City Gates**	**31,320**	**52,913**	**47,469**	**100,383**	**58,991**	WP-MPG-6
7%	Labor	1,925	3,445	3,091	6,536	3,841	
23%	Capitalized Engineering/Supv	7,333	12,010	10,774	22,784	13,389	
17%	Materials	5,004	9,082	8,147	17,229	10,125	
36%	Contractor	12,499	19,134	17,166	36,300	21,332	
1%	Non-Labor Overhead	417	625	561	1,186	697	
16%	Non-Labor Other	4,142	8,616	7,730	16,346	9,606	
7	**Total Capacity/Deliverability Capital**	**308,275**	**270,203**	**133,076**	**403,278**	**170,372**	
	Labor	11,914	13,608	9,805	23,413	12,667	
	Capitalized Engineering/Supv	26,037	29,286	29,500	58,786	39,771	
	Materials	21,737	21,202	17,647	38,849	24,199	
	Contractor	211,260	177,467	58,404	235,871	73,193	
	Non-Labor Overhead	1,716	1,810	1,323	3,132	1,655	
	Non-Labor Other	35,610	26,829	16,397	43,226	18,887	

Unless noted otherwise, capital "other" costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).

This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for all programs and projects except for the Mid-Michigan Pipeline MMPL) for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop projected test year costs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Transmission and Distribution Capital Expenditures
Capacity/Deliverability Program

Case No.: U-21806
Exhibit No.: A-61 (MPG-5) **Revised**
Page: 2 of 3
Witness: MPGriffin

($000) Date: December 2024

	(a)	(b)	(c)	(d)	(e)
		Projected			
		10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
8	**Transmission Enhancements for Deliverabil**	**138,586**	**28,397**	**19,145**	**186,127**
	Labor	3,245	1,458	1,029	5,732
	Capitalized Engineering/Supv	67	3,084	4,135	7,285
	Materials	2,626	939	662	4,227
	Contractor	123,056	20,130	10,523	153,709
	Non-Labor Overhead	423	81	26	531
	Non-Labor Other	9,169	2,705	2,770	14,644
9	**Misc Transmission & Compression**	**23**	**(1)**	**0**	**22**
5%	Labor	1	(0)	0	1
26%	Capitalized Engineering/Supv	6	(0)	0	6
-1%	Materials	(0)	0	0	(0)
49%	Contractor	11	(0)	0	11
0%	Non-Labor Overhead	0	0	0	0
20%	Non-Labor Other	5	(0)	0	4
10	**Deliverability Base Field Measurement**	**4,518**	**12,511**	**19,890**	**36,919**
5%	Labor	208	577	917	1,702
24%	Capitalized Engineering/Supv	1,083	2,999	4,768	8,851
25%	Materials	1,123	3,110	4,945	9,178
71%	Contractor	3,225	8,929	14,196	26,351
0%	Non-Labor Overhead	21	58	93	172
-25%	Non-Labor Other	(1,142)	(3,163)	(5,029)	(9,334)
11	**Deliverability Base Pipeline**	**14,136**	**23,440**	**25,073**	**62,648**
8%	Labor	1,154	1,913	2,047	5,114
23%	Capitalized Engineering/Supv	3,308	5,486	5,868	14,662
13%	Materials	1,857	3,079	3,293	8,229
43%	Contractor	6,149	10,196	10,906	27,251
1%	Non-Labor Overhead	201	334	357	892
10%	Non-Labor Other	1,467	2,432	2,601	6,500
12	**Regulator Stations - Distribution**	**42,319**	**39,410**	**47,274**	**129,003**
10%	Labor	4,327	4,029	4,834	13,190
25%	Capitalized Engineering/Supv	10,394	9,679	11,610	31,683
11%	Materials	4,632	4,313	5,174	14,119
34%	Contractor	14,533	13,534	16,235	44,302
1%	Non-Labor Overhead	432	402	482	1,315
19%	Non-Labor Other	8,002	7,452	8,939	24,393
13	**T&S City Gates**	**46,174**	**54,209**	**58,991**	**159,373**
7%	Labor	3,007	3,530	3,841	10,378
23%	Capitalized Engineering/Supv	10,480	12,304	13,389	36,174
17%	Materials	7,925	9,304	10,125	27,354
36%	Contractor	16,697	19,603	21,332	57,632
1%	Non-Labor Overhead	546	640	697	1,883
16%	Non-Labor Other	7,519	8,827	9,606	25,952
13	**Total Capacity/Deliverability Capital**	**245,755**	**157,965**	**170,372**	**574,092**
	Labor	11,942	11,507	12,667	36,116
	Capitalized Engineering/Supv	25,338	33,552	39,771	98,660
	Materials	18,162	20,745	24,199	63,106
	Contractor	163,672	72,392	73,193	309,256
	Non-Labor Overhead	1,623	1,516	1,655	4,794
	Non-Labor Other	25,019	18,253	18,887	62,160

This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for all programs and projects except for the Mid-Michigan Pipeline MMPL) for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop projected test year costs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Transmission and Distribution Capital Expenditures
Capacity/Deliverability Program
($000)

Case No.: U-21806
Exhibit No.: A-61 (MPG-5) **Revised**
Page: 3 of 3
Witness: MPGriffin
Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Year 12 Mos Ending 12/31/2024	(d) Projected Bridge Year 10 Mos Ending 10/31/2025	(e) Projected Bridge Year 22 Mos Ending 10/31/2025 [Col. (c) + (d)]	(f) Projected Test Year 12 Mos Ending 10/31/2026
	Projects Over $5 Million					
1	**Transmission Enhancements for Deliverability & Integrity ("TED-I")**					
2	TED-I 100A Ovid to Will Pipe Repl	13,864	133,598	6,741	140,339	389
3	STC-Oakland Resilience Interconnect	53	1,161	4,466	5,628	45
4	**Misc Transmission & Compression**					
5	None Identified	-	-	-	-	-
6	**Deliverability Base Field Measurement**					
7	SAG-Grand Blanc Mtr Run Repl	13	1,286	4,320	5,606	524
8	Williamston Transmission Meter Proving Station	-	200	226	426	7,994
9	Northville CS Line 1200 A Meter and Chromatograph Install	-	-	-	-	4,889
10	**Deliverability Base Pipeline**					
11	None identified	-	-	-	-	-
12	**Regulator Stations - Distribution**					
13	MID-63-245 Poseyville Sta Rbld	-	17	4,366	4,383	622
14	**T&S City Gates**					
15	STC-Orion CG Rbld	888	11,942	44	11,986	6
16	JXN-PEPL-Blissfield CG Rbld	1,217	9,479	44	9,523	6
17	FDM-Bancroft CG Rbld	156	1,214	7,472	8,686	1,211
18	JXN-Jxn Hart Rd CG Rbld	-	788	7,436	8,224	1,207
19	FDM-Hanover Horton CG Rbld	-	581	5,926	6,506	1,017
20	SAG-Flint Torrey Rd CG Rebl	-	1,062	6,800	7,862	1,127
21	NVL-Highland CG, Odorizer Rbld	-	880	7,770	8,650	1,249
22	Spring Arbor CG - PEPL & Odorizer	-	-	877	877	7,861
23	Flint CG Irish & Odorizer	-	-	877	877	7,501
24	Climax CG - PEPL	-	-	755	755	8,647
25	South Lyon - Whitmore Lake CG & Odorizer	-	-	472	472	7,912
26	Mendon Leonidas & Odorizer	-	-	472	472	8,611
	Projects Under $5 Million					
27	Transmission Enhancements for Deliverability & Integrity ("TED-I")	202,444	12,031	8,984	21,015	18,711
28	Misc Transmission & Compression	257	22	-	22	-
29	Deliverability Base Field Measurement	5,306	5,288	5,709	10,997	6,484
30	Deliverability Base Pipeline	18,757	18,014	19,120	37,134	25,073
31	Regulator Stations - Distribution	36,262	45,673	31,673	77,346	46,651
32	T&S City Gates	29,059	26,967	8,524	35,491	12,637
33	**Total Capital**	308,275	270,203	133,076	403,278	170,372

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Transmission and Distribution Capital Expenditures
Capacity/Deliverability Program
($000)

Case No.: U-21806
Exhibit No.: A-61 (MPG-5)
Page: 1 of 3
Witness: MPGriffin
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)	
		Historical Year	Projected Bridge Year			Projected Test Year	
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	Source
1	**Transmission Enhancements for Deliverability & Integrity ("TED-I")**	**216,361**	**146,790**	**20,192**	**166,982**	**19,145**	Exhibit A-62 (MPG-6)
	Labor	4,591	3,708	995	4,703	1,029	
	Capitalized Engineering/Supv	3,840	209	2,941	3,150	4,135	
	Materials	10,204	3,070	494	3,564	662	
	Contractor	172,830	129,961	13,225	143,186	10,523	
	Non-Labor Overhead	607	430	74	505	26	
	Non-Labor Other	24,289	9,413	2,461	11,874	2,770	
2	**Misc Transmission & Compression**	**257**	**22**	**0**	**22**	**0**	
5%	Labor	7	1	0	1	0	
26%	Capitalized Engineering/Supv	69	6	0	6	0	
-1%	Materials	(4)	(0)	0	(0)	0	
49%	Contractor	131	11	0	11	0	
0%	Non-Labor Overhead	0	0	0	0	0	
20%	Non-Labor Other	55	4	0	4	0	
3	**Deliverability Base Field Measurement**	**5,319**	**6,774**	**10,255**	**17,029**	**19,890**	WP-MPG-3
5%	Labor	266	312	473	785	917	
24%	Capitalized Engineering/Supv	1,339	1,624	2,458	4,082	4,768	
25%	Materials	1,110	1,684	2,549	4,233	4,945	
71%	Contractor	4,161	4,835	7,319	12,154	14,196	
0%	Non-Labor Overhead	26	32	48	79	93	
-25%	Non-Labor Other	(1,585)	(1,713)	(2,593)	(4,306)	(5,029)	
4	**Deliverability Base Pipeline**	**18,757**	**18,173**	**19,403**	**37,576**	**25,023**	WP-MPG-4
8%	Labor	1,560	1,483	1,584	3,067	2,042	
23%	Capitalized Engineering/Supv	4,428	4,253	4,541	8,794	5,856	
13%	Materials	2,152	2,387	2,549	4,936	3,287	
43%	Contractor	8,422	7,905	8,440	16,345	10,885	
1%	Non-Labor Overhead	292	259	276	535	356	
10%	Non-Labor Other	1,902	1,886	2,013	3,899	2,596	
5	**Regulator Stations - Distribution**	**36,262**	**45,690**	**36,039**	**81,729**	**47,274**	WP-MPG-5
10%	Labor	3,565	4,672	3,685	8,356	4,834	
25%	Capitalized Engineering/Supv	9,028	11,221	8,851	20,073	11,610	
11%	Materials	3,270	5,001	3,944	8,945	5,174	
34%	Contractor	13,217	15,691	12,377	28,068	16,235	
1%	Non-Labor Overhead	374	466	367	833	482	
19%	Non-Labor Other	6,808	8,640	6,815	15,454	8,939	
6	**T&S City Gates**	**31,320**	**52,913**	**47,469**	**100,383**	**58,991**	WP-MPG-6
7%	Labor	1,925	3,445	3,091	6,536	3,841	
23%	Capitalized Engineering/Supv	7,333	12,010	10,774	22,784	13,389	
17%	Materials	5,004	9,082	8,147	17,229	10,125	
36%	Contractor	12,499	19,134	17,166	36,300	21,332	
1%	Non-Labor Overhead	417	625	561	1,186	697	
16%	Non-Labor Other	4,142	8,616	7,730	16,346	9,606	
7	**Total Capacity/Deliverability Capital**	**308,275**	**270,362**	**133,358**	**403,720**	**170,322**	
	Labor	11,914	13,621	9,828	23,449	12,663	
	Capitalized Engineering/Supv	26,037	29,323	29,566	58,889	39,759	
	Materials	21,737	21,223	17,684	38,907	24,192	
	Contractor	211,260	177,537	58,527	236,064	73,171	
	Non-Labor Overhead	1,716	1,812	1,327	3,139	1,654	
	Non-Labor Other	35,610	26,846	16,426	43,272	18,882	

Unless noted otherwise, capital "other" costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).

This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for all programs and projects except for the Mid-Michigan Pipeline MMPL) for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop projected test year costs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Transmission and Distribution Capital Expenditures
Capacity/Deliverability Program
($000)

Case No.: U-21806
Exhibit No.: A-61 (MPG-5)
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Witness: MPGriffin
Date: December 2024

	(a)	(b)	(c)	(d)	(e)
		Projected			
		10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
8	**Transmission Enhancements for Deliverabil**	**138,586**	**28,397**	**19,145**	**186,127**
	Labor	3,245	1,458	1,029	5,732
	Capitalized Engineering/Supv	67	3,084	4,135	7,285
	Materials	2,626	939	662	4,227
	Contractor	123,056	20,130	10,523	153,709
	Non-Labor Overhead	423	81	26	531
	Non-Labor Other	9,169	2,705	2,770	14,644
9	**Misc Transmission & Compression**	**23**	**(1)**	**0**	**22**
5%	Labor	1	(0)	0	1
26%	Capitalized Engineering/Supv	6	(0)	0	6
-1%	Materials	(0)	0	0	(0)
49%	Contractor	11	(0)	0	11
0%	Non-Labor Overhead	0	0	0	0
20%	Non-Labor Other	5	(0)	0	4
10	**Deliverability Base Field Measurement**	**4,518**	**12,511**	**19,890**	**36,919**
5%	Labor	208	577	917	1,702
24%	Capitalized Engineering/Supv	1,083	2,999	4,768	8,851
25%	Materials	1,123	3,110	4,945	9,178
71%	Contractor	3,225	8,929	14,196	26,351
0%	Non-Labor Overhead	21	58	93	172
-25%	Non-Labor Other	(1,142)	(3,163)	(5,029)	(9,334)
11	**Deliverability Base Pipeline**	**14,136**	**23,440**	**25,023**	**62,598**
8%	Labor	1,154	1,913	2,042	5,110
23%	Capitalized Engineering/Supv	3,308	5,486	5,856	14,650
13%	Materials	1,857	3,079	3,287	8,222
43%	Contractor	6,149	10,196	10,885	27,230
1%	Non-Labor Overhead	201	334	356	892
10%	Non-Labor Other	1,467	2,432	2,596	6,495
12	**Regulator Stations - Distribution**	**42,319**	**39,410**	**47,274**	**129,003**
10%	Labor	4,327	4,029	4,834	13,190
25%	Capitalized Engineering/Supv	10,394	9,679	11,610	31,683
11%	Materials	4,632	4,313	5,174	14,119
34%	Contractor	14,533	13,534	16,235	44,302
1%	Non-Labor Overhead	432	402	482	1,315
19%	Non-Labor Other	8,002	7,452	8,939	24,393
13	**T&S City Gates**	**46,174**	**54,209**	**58,991**	**159,373**
7%	Labor	3,007	3,530	3,841	10,378
23%	Capitalized Engineering/Supv	10,480	12,304	13,389	36,174
17%	Materials	7,925	9,304	10,125	27,354
36%	Contractor	16,697	19,603	21,332	57,632
1%	Non-Labor Overhead	546	640	697	1,883
16%	Non-Labor Other	7,519	8,827	9,606	25,952
13	**Total Capacity/Deliverability Capital**	**245,755**	**157,965**	**170,322**	**574,042**
	Labor	11,942	11,507	12,663	36,112
	Capitalized Engineering/Supv	25,338	33,552	39,759	98,648
	Materials	18,162	20,745	24,192	63,100
	Contractor	163,672	72,392	73,171	309,234
	Non-Labor Overhead	1,623	1,516	1,654	4,793
	Non-Labor Other	25,019	18,253	18,882	62,154

This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for all programs and projects except for the Mid-Michigan Pipeline MMPL) for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop projected test year costs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Transmission and Distribution Capital Expenditures
Capacity/Deliverability Program
($000)

Case No.: U-21806
Exhibit No.: A-61 (MPG-5)
Page: 3 of 3
Witness: MPGriffin
Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Year 12 Mos Ending 12/31/2024	(d) Projected Bridge Year 10 Mos Ending 10/31/2025	(e) Projected Bridge Year 22 Mos Ending 10/31/2025 [Col. (c) + (d)]	(f) Projected Test Year 12 Mos 10/31/2026
	Projects Over $5 Million					
1	**Transmission Enhancements for Deliverability & Integrity ("TED-I")**					
2	TED-I 100A Ovid to Will Pipe Repl	13,864	133,598	6,741	140,339	389
3	STC-Oakland Resilience Interconnect	53	1,161	4,466	5,628	45
4	**Misc Transmission & Compression**					
5	None Identified	-	-	-	-	-
6	**Deliverability Base Field Measurement**					
7	SAG-Grand Blanc Mtr Run Repl	13	1,286	4,320	5,606	524
8	Williamston Transmission Meter Proving Station	-	200	226	426	7,994
9	Northville CS Line 1200 A Meter and Chromatograph Install	-	-	-	-	4,889
10	**Deliverability Base Pipeline**					
11	None identified	-	-	-	-	-
12	**Regulator Stations - Distribution**					
13	MID-63-245 Poseyville Sta Rbld	-	17	4,366	4,383	622
14	**T&S City Gates**					
15	STC-Orion CG Rbld	888	11,942	44	11,986	6
16	JXN-PEPL-Blissfield CG Rbld	1,217	9,479	44	9,523	6
17	FDM-Bancroft CG Rbld	156	1,214	7,472	8,686	1,211
18	JXN-Jxn Hart Rd CG Rbld	-	788	7,436	8,224	1,207
19	FDM-Hanover Horton CG Rbld	-	581	5,926	6,506	1,017
20	SAG-Flint Torrey Rd CG Rebl	-	1,062	6,800	7,862	1,127
21	NVL-Highland CG, Odorizer Rbld	-	880	7,770	8,650	1,249
22	Spring Arbor CG - PEPL & Odorizer	-	-	877	877	7,861
23	Flint CG Irish & Odorizer	-	-	877	877	7,501
24	Climax CG - PEPL	-	-	755	755	8,647
25	South Lyon - Whitmore Lake CG & Odorizer	-	-	472	472	7,912
26	Mendon Leonidas & Odorizer	-	-	472	472	8,611
	Projects Under $5 Million					
27	Transmission Enhancements for Deliverability & Integrity ("TED-I")	202,444	12,031	8,984	21,015	18,711
28	Misc Transmission & Compression	257	22	-	22	-
29	Deliverability Base Field Measurement	5,306	5,288	5,709	10,997	6,484
30	Deliverability Base Pipeline	18,757	18,173	19,403	37,576	25,023
31	Regulator Stations - Distribution	36,262	45,673	31,673	77,346	46,651
32	T&S City Gates	29,059	26,967	8,524	35,491	12,637
33	**Total Capital**	308,275	270,362	133,358	403,720	170,322

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Capital Expenditures
Transmission & Distribution Plant
TED-I Program Detail
($000)

Case No.: U-21806
Exhibit No.: A-62 (MPG-6)
Page: 1 of 2
Witness: MPGriffin
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)	
		Historical Year	Projected Bridge Year			Projected Test Year	
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	Source
1	**Mid-Michigan Pipeline Project**	**201,391**	**145,589**	**6,935**	**152,525**	**389**	WP-MPG-7
	Labor	3,995	3,658	263	3,921	0	
	Capitalized Engineering/Supv	203	77	0	77	0	
	Materials	9,605	2,284	0	2,284	0	
	Contractor	163,965	129,834	5,920	135,754	335	
	Non-Labor Overhead	528	428	57	485	0	
	Non-Labor Other	23,095	9,308	696	10,004	54	
2	**Pressure Limiting Devices (PLDs) Summary**	**12,156**	**(133)**	**0**	**(133)**	**0**	WP-MPG-9
	Labor	340	(2)	0	(2)	0	
	Capitalized Engineering/Supv	3,036	(32)	0	(32)	0	
	Materials	333	(7)	0	(7)	0	
	Contractor	7,521	(84)	0	(84)	0	
	Non-Labor Overhead	48	1	0	1	0	
	Non-Labor Other	878	(9)	0	(9)	0	
3	**Remote Closure Valves (RCVs) Summary**	**2,253**	**(103)**	**8,717**	**8,613**	**18,074**	WP-MPG-8
	Labor	170	11	490	502	1,019	
	Capitalized Engineering/Supv	584	(47)	1,950	1,903	4,094	
	Materials	281	13	328	340	656	
	Contractor	936	(126)	4,794	4,668	9,589	
	Non-Labor Overhead	29	1	11	12	26	
	Non-Labor Other	254	44	1,144	1,188	2,690	
4	**Pipeline & Other Installation/Modifications Summary**	**561**	**1,437**	**4,540**	**5,977**	**682**	WP-MPG-10
	Labor	86	40	243	282	10	
	Capitalized Engineering/Supv	16	211	991	1,202	40	
	Materials	(15)	780	167	947	7	
	Contractor	409	336	2,511	2,848	599	
	Non-Labor Overhead	2	1	6	8	0	
	Non-Labor Other	62	69	622	690	25	
5	**Total TED-I Capital**	**216,361**	**146,790**	**20,192**	**166,982**	**19,145**	
	Labor	4,591	3,708	995	4,703	1,029	
	Capitalized Engineering/Supv	3,840	209	2,941	3,150	4,135	
	Materials	10,204	3,070	494	3,564	662	
	Contractor	172,830	129,961	13,225	143,186	10,523	
	Non-Labor Overhead	607	430	74	505	26	
	Non-Labor Other	24,289	9,413	2,461	11,874	2,770	

Unless noted otherwise, capital "other" costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Capital Expenditures
Transmission & Distribution Plant
TED-I Program Detail
($000)

Case No.: U-21806
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	(a)	(b)	(c)	(d)	(e)	(f)
		Projected				
		10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026	
6	**Mid-Michigan Pipeline Project**	**138,264**	**14,261**	**389**	**152,914**	
	Labor	3,207	714	0	3,921	
	Capitalized Engineering/Supv	77	0	0	77	
	Materials	2,284	0	0	2,284	
	Contractor	123,145	12,609	335	136,089	
	Non-Labor Overhead	421	64	0	485	
	Non-Labor Other	9,130	874	54	10,058	
7	**Pressure Limiting Devices (PLDs) Summary**	**(133)**	**0**	**0**	**(133)**	
	Labor	(2)	0	0	(2)	
	Capitalized Engineering/Supv	(32)	0	0	(32)	
	Materials	(7)	0	0	(7)	
	Contractor	(84)	0	0	(84)	
	Non-Labor Overhead	1	0	0	1	
	Non-Labor Other	(9)	0	0	(9)	
8	**Remote Closure Valves (RCVs) Summary**	**(108)**	**8,722**	**18,074**	**26,687**	
	Labor	11	490	1,019	1,521	
	Capitalized Engineering/Supv	(47)	1,950	4,094	5,997	
	Materials	13	328	656	996	
	Contractor	(126)	4,794	9,589	14,257	
	Non-Labor Overhead	1	11	26	38	
	Non-Labor Other	39	1,149	2,690	3,879	
9	**Pipeline & Other Installation/Modifications Summary**	**563**	**5,414**	**682**	**6,658**	
	Labor	28	254	10	292	
	Capitalized Engineering/Supv	68	1,134	40	1,243	
	Materials	336	611	7	954	
	Contractor	121	2,726	599	3,447	
	Non-Labor Overhead	1	7	0	8	
	Non-Labor Other	8	682	25	716	
10	**Total TED-I Capital**	**138,586**	**28,397**	**19,145**	**186,127**	
	Labor	3,245	1,458	1,029	5,732	
	Capitalized Engineering/Supv	67	3,084	4,135	7,285	
	Materials	2,626	939	662	4,227	
	Contractor	123,056	20,130	10,523	153,709	
	Non-Labor Overhead	423	81	26	531	
	Non-Labor Other	9,169	2,705	2,770	14,644	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Transmission & Distribution Plant
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-63 (MPG-7)
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Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
				Capital Expenditures			
Line No.	**Program Description**	**Historic Test Year 2023 Actual**	**Last Rate Case Approved Spending Plan Case No. U-21490 12 mos. Ending 9/30/2025 (1)**	**Last Rate Case Actual Spending Case No. U-21490 12 mos. Ending 9/30/2025 (2)**	**Variation Percentage (1)**	**Location of Testimony Regarding Significant Var (1) (>10%)**	**Current Case Projection 12 mos. Ending 10/31/2026**
1	Asset Relocation	6,168	n/a	n/a	n/a	n/a	24,726
2	Regulatory Compliance	36,139	n/a	n/a	n/a	n/a	24,807
3	Capacity/Deliverability	308,275	n/a	n/a	n/a	n/a	170,322
4	**Total Capital**	350,582	-	-			219,855

Footnote:

[1] Case No. U-21490 resulted in a settlement agreement that did not state approved capital spending amounts for the programs represented here

[2] The projected test year in Case No. U-21490 has not transpired as of the date of this filing

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual and Projected Employee Benefits O&M Expenses
For the Years 2023 and Test Year 12 Months ending October 31, 2026
($000)

Case No.: U-21806
Exhibit No.: A-64 (KKG-1)
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Witness: KKGrob
Date: December 2024

Line No.	(a) Description	(b) Actual 12 mos. ended 12/31/2023	(c) Projected 12 mos. Ending 10/31/26
1	Pension Plans A/B	**($28,482)**	**($34,801)**
2	Defined Company Contribution Plan	**7,952**	**8,155**
3	401 (k) Employees' Savings Plan	**6,449**	**6,615**
4	Active Health Care/Life Insurance/LTD	**18,359**	**19,765**
5	Retiree Health Care and Life Insurance	**(33,761)**	**(42,702)**
6	Other Benefits	**2,493**	**3,218**
7	Pension Volatility Mechanism Deferral	**(266)**	**0**
8	OPEB Volatility Mechanism Deferral	**655**	**0**
9	Pension Volatility Mechanism Amortization	**0**	**(791)**
10	OPEB Volatility Mechanism Amortization	**0**	**(1,423)**
11	**Total Expense**	**($26,601)**	**($41,964)**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Merit and Inflation
Actual and Projected Employee Benefits O&M Expenses
($000)

Case No.: U-21806
Exhibit No.: A-64 (KKG-1)
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Witness: KKGrob
Date: December 2024

Line No.	Description	2023 Actual	Base O&M for Merit & Inflation 12 Mos Ended Dec 31, 2023	Merit & Inflation 12 Mos Ending Dec 31, 2024	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	Merit & Inflation 12 Mos Ending Dec 31, 2025	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	Merit & Inflation 10 Mos Ending 10/31/2026	Other Adjustments	Projected O&M 12 Mos Ending 10/31/2026
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
				(c)* Inflation Rate		(e)* Inflation Rate		(g)* Inflation Rate		(b)+(d)+(f)+(h)+(i)
1	**Pension Plans A/B**	$ (28,482)	$ (28,482)	$ (911)	$ (29,393)	$ (705)	$ (30,099)	$ (627)	($4,075)	$ (34,801)
2	**Defined Company Contribution Plan**	$ 7,952	$ 7,952	$ 254	$ 8,206	$ 197	$ 8,403	$ 175	$ (423)	$ 8,155
3	**401 (k) Employees' Savings Plan**	$ 6,449	$ 6,449	$ 206	$ 6,655	$ 160	$ 6,815	$ 142	$ (342)	$ 6,615
4	**Active Health Care/Life Insurance/LTD**	$ 18,359	$ 18,359	$ 587	$ 18,946	$ 455	$ 19,401	$ 404	$ (40)	$ 19,765
5	**Retiree Health Care and Life Insurance**	$ (33,761)	$ (33,761)	$ (1,080)	$ (34,841)	$ (836)	$ (35,678)	$ (743)	$ (6,281)	$ (42,702)
6	**Other Benefits**	$ 2,493	$ 2,493	$ 80	$ 2,573	$ 62	$ 2,635	$ 55	$ 529	$ 3,218
	Other Benefits non labor	1,595	1,595	51	1,646	40	1,686	35	(44)	1,677
	Other Benefits labor	898	898	29	927	22	949	20	572	1,541
7	**Pension Volatility Mechanism Deferral**	$ (266)	$ (266)	$ (9)	$ (275)	$ (7)	$ (281)	$ (6)	$287	$ (0)
8	**OPEB Volatility Mechanism Deferral**	$ 655	$ 655	$ 21	$ 676	$ 16	$ 692	$ 14	($707)	$ -
9	**Pension Volatility Mechanism Amortization**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	($791)	$ (791)
10	**OPEB Volatility Mechanism Amortization**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	($1,423)	$ (1,423)
11	**Total Employee Benefits O&M Expenses**	$ (26,601)	$ (26,601)	$ (851)	$ (27,452)	$ (659)	$ (28,111)	$ (586)	$ (13,267)	$ (41,964)
	Nonlabor	$ (27,499)	$ (27,499)	$ (880)	$ (28,379)	$ (681)	$ (29,060)	$ (605)	$ (13,840)	$ (43,505)
	Labor	898	898	29	927	22	949	20	572	1,541

Notes

	12-Mo Ending 2024	12-Mo Ending 2025	10-Mo Ending 2026
Annual inflation rates per Company witness Rayl	3.2%	2.4%	2.5%
Number of months in the period	12	12	10
Pro-rated inflation rate	3.2%	2.4%	2.1%

CMS Energy

Prepared on January 17, 2024

ASC 715 (Formerly FAS 87) Pension Expense Estimates ($ millions)
HATFA Minimum Required Contributions - Baseline Scenario

	2023	2024	2025	2026
Contribution by Plan Year				
Utility	$ 0.0	$ 0.0	$ 0.0	$ 0.0
Nonutility	0.0	0.0	0.0	0.0
Total	$ 0.0	$ 0.0	$ 0.0	$ 0.0
At-Risk?	No	No	No	No
Benefit Restrictions?	No	No	No	No
Participant Count	2,858	2,766	2,689	2,607
PBGC Liability	$ 1,344.2	$ 1,150.7	$ 1,021.7	$ 1,006.8
Market Value of Assets	$ 1,633.9	$ 1,758.4	$ 1,808.9	$ 1,859.6
PBGC Flat Rate Premium	$ 0.3	$ 0.3	$ 0.3	$ 0.3
PBGC Variable Rate Premium	0.0	0.0	0.0	0.0
Total PBGC Premium	$ 0.3	$ 0.3	$ 0.3	$ 0.3
Projected Benefit Obligation	$ 1,238.2	$ 1,280.9	$ 1,290.9	$ 1,295.5
Market Value of Assets	1,633.9	1,758.4	1,808.9	1,859.6
Funded Status	$ (395.7)	$ (477.5)	$ (518.0)	$ (564.1)
ASC 715 Funded %	132.0%	137.3%	140.1%	143.5%
ASC 715 Accounting Expense				
Utility	$ (32.6)	$ (42.4)	$ (46.0)	$ (48.5)
Nonutility	(0.9)	(1.2)	(1.3)	(1.4)
Total ASC 715 Accounting Expense	$ (33.5)	$ (43.6)	$ (47.3)	$ (49.9)
2020 Settlement Accounting Utility Amortization[1]	5.3	5.3	5.3	5.3
2021 Settlement Accounting Utility Amortization[2]	2.6	2.6	2.6	2.6
2022 Settlement Accounting Utility Amortization[3]	2.7	2.7	2.7	2.7
Total Expense	$ (22.9)	$ (33.0)	$ (36.7)	$ (39.3)
Components of Total Expense				
Service Cost	$ 27.9	$ 26.1	$ 24.5	$ 22.5
Interest Cost	61.4	61.3	61.6	61.8
Expected Return on Assets	(127.1)	(135.3)	(137.1)	(137.1)
Amortization of Outstanding Components	4.3	4.3	3.7	2.9
Total ASC 715 Accounting Expense	$ (33.5)	$ (43.6)	$ (47.3)	$ (49.9)
2020 Settlement Accounting Utility Amortization[1]	5.3	5.3	5.3	5.3
2021 Settlement Accounting Utility Amortization[2]	2.6	2.6	2.6	2.6
2022 Settlement Accounting Utility Amortization[3]	2.7	2.7	2.7	2.7
Total Expense	$ (22.9)	$ (33.0)	$ (36.7)	$ (39.3)
Market Related Value of Assets	$ 1,804.2	$ 1,842.2	$ 1,868.4	$ 1,869.9
Assumptions				
Discount Rate	5.24%	5.05%	5.05%	5.05%
Expected Return on Assets	7.25%	7.50%	7.50%	7.50%
Salary Increases	3.55%	3.55%	3.55%	3.55%

[1] The information related to the 2020 Settlement Accounting Utility Amortization was provided directly by CMS and was not calculated or reviewed by Aon. The amortization was set up as a regulatory asset for the utility portion of the 2020 settlement loss of $35.5 million at August 31, 2020. As provided by CMS, the amortizations starts in September 2020 over service life of 8.55 years. Additionally, the settlement attributable to the utility portion on December 31, 2020 is $9.8 million, which is also amortized over service of 8.55 years beginning in January 2021. Nonutility portions of the settlement loss are $0.9 million and $0.3 million for August 31, 2020 and December 31, 2020 respectively.

[2] The information related to the 2021 Settlement Accounting Utility Amortization was provided directly by CMS and was not calculated or reviewed by Aon. The amortization was set up as a regulatory asset for the utility portion of the 2021 settlement loss of $17.6 million at October 31, 2021. As provided by CMS, the amortizations starts in November 2021 over service life of 8.19 years. Additionally, the settlement attributable to the utility portion on December 31, 2021 is $3.3 million, which is also amortized over service of 8.19 years beginning in January 2022. Nonutility portions of the settlement loss are $0.5 million and $0.1 million for October 31, 2021 and December 31, 2021 respectively.

[3] The information related to the 2022 Settlement Accounting Utility Amortization was provided directly by CMS and was not calculated or reviewed by Aon. The amortizations were set up as regulatory assets for the utility portions of the 2022 settlement losses. The settlements attributable to the utility portions are $3.9 million, $3.7 million, $11.5 million, and $2.5 million as of March 31, 2022, June 30, 2022, September 30, 2022, and December 31, 2022 respectively. As provided by CMS, the amortizations are amortized over service life of 8.11 years beginning in April 2022, July 2022, October 2022, and January 2023 respectively. Nonutility portions of the settlement loss are $0.1 million, $0.1 million, $0.3 million, and $0.1 million for March 31, 2022, June 30, 2022, September 30, 2022, and December 31, 2022 respectively.

CMS Energy

Prepared on January 17, 2024

ASC 715 (Formerly FAS 87) Pension Expense Estimates ($ millions)
HATFA Minimum Required Contributions - Baseline Scenario

	2023	2024	2025	2026
Contribution by Plan Year				
Utility	$ 0.0	$ 0.0	$ 0.0	$ 0.0
Nonutility	0.0	0.0	0.0	0.0
Total	$ 0.0	$ 0.0	$ 0.0	$ 0.0
At-Risk?	No	No	No	No
Benefit Restrictions?	No	No	No	No
Participant Count	7,502	7,337	7,166	6,987
PBGC Liability	$ 1,128.3	$ 946.1	$ 828.7	$ 778.2
Market Value of Assets	$ 1,185.6	$ 1,245.9	$ 1,254.8	$ 1,265.8
PBGC Flat Rate Premium	$ 0.7	$ 0.7	$ 0.7	$ 0.7
PBGC Variable Rate Premium	0.0	0.0	0.0	0.0
Total PBGC Premium	$ 0.7	$ 0.7	$ 0.7	$ 0.7
Projected Benefit Obligation	$ 930.5	$ 914.4	$ 875.4	$ 838.2
Market Value of Assets	1,185.6	1,245.9	1,254.8	1,265.8
Funded Status	$ (255.1)	$ (331.5)	$ (379.4)	$ (427.6)
ASC 715 Funded %	127.4%	136.3%	143.3%	151.0%
ASC 715 Accounting Expense				
Utility	$ (32.1)	$ (38.9)	$ (39.1)	$ (37.1)
Nonutility	(3.3)	(4.1)	(4.1)	(3.9)
Total	$ (35.4)	$ (43.0)	$ (43.2)	$ (41.0)
Components of Total Expense				
Service Cost	$ 1.5	$ 1.6	$ 1.6	$ 1.6
Interest Cost	45.0	42.6	40.7	38.9
Expected Return on Assets	(93.1)	(98.6)	(97.9)	(96.1)
Amortization of Outstanding Components	11.2	11.4	12.4	14.6
Total Expense	$ (35.4)	$ (43.0)	$ (43.2)	$ (41.0)
Market Related Value of Assets	$ 1,333.7	$ 1,354.1	$ 1,345.8	$ 1,321.2
Assumptions				
Discount Rate	5.14%	4.95%	4.95%	4.95%
Expected Return on Assets	7.20%	7.50%	7.50%	7.50%
Salary Increases	3.60%	3.65%	3.65%	3.65%

2024-2026 projections reflect the following:

- January 1, 2023 census data.
- PBO discount rate of 5.05% (Plan A) and 4.95% (Plan B) in fiscal 2024+, based on December 31, 2023 yield curve anlaysis.
- Service Cost effective interest rate of 5.08% (Plan A) and 5.12% (Plan B) in fiscal 2024+, based on December 31, 2023 yield curve analysis.
- Interest Cost effective interest rate of 4.93% (Plan A) and 4.87% (Plan B) in fiscal 2024+, based on December 31, 2023 yield curve analysis.
- Expense is allocated to Utility/Non Utility based on PBO using the preliminary allocation percentages for 2024 expense.
- Contributions are allocated to Utility/Non Utility based on the most recent allocation percentages provided by CMS for the December 2020 contributions.
- December 31, 2023 market assets provided by CMS, with expected returns thereafter.
- Expected and actual asset returns of 7.50% in fiscal 2024+.
- The plans will waive Funding Balance when necessary, in order to maintain a Funded Percentage of at least 80%.
- Other provisions, assumptions and methods are the same as those used for the December 31, 2023 ASC 715 disclosures.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

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CMS Energy

Prepared on January 17, 2024

ASC 715 OPEB Expense Estimates ($ millions)

	2023	2024	2025	2026
Funded Status, January 1				
Accumulated Postretirement Benefit Obligation	$ (889.4)	$ (899.9)	$ (900.1)	$ (898.4)
Plan Assets at Fair Value	$ 1,446.5	$ 1,558.9	$ 1,618.8	$ 1,681.6
Funded Status	$ 557.1	$ 659.0	$ 718.7	$ 783.2
ASC 715 Accounting Expense				
Utility	$ (70.2)	$ (80.8)	$ (85.4)	$ (89.3)
Nonutility	$ (6.0)	$ (6.7)	$ (7.1)	$ (7.3)
Total	$ (76.2)	$ (87.5)	$ (92.5)	$ (96.6)
Components of Total Expense				
Service Cost	$ 11.6	$ 11.3	$ 11.0	$ 10.8
Interest Cost	$ 44.0	$ 42.9	$ 42.8	$ 42.7
Expected Return on Assets	$ (102.3)	$ (114.8)	$ (119.3)	$ (124.0)
Amortization of Net (Gain) or Loss	$ 11.7	$ 3.9	$ 3.0	$ 2.1
Amortization of Prior Service Cost	$ (41.2)	$ (30.8)	$ (30.0)	$ (28.2)
Total Expense	$ (76.2)	$ (87.5)	$ (92.5)	$ (96.6)
Assumptions				
APBO Discount Rate	5.21%	5.02%	5.02%	5.02%
Service Cost Effective Interest Rate	5.31%	5.12%	5.12%	5.12%
Interest Cost Effective Interest Rate	5.10%	4.91%	4.91%	4.91%
Expected Return on Assets	7.20%	7.50%	7.50%	7.50%
Trend Rate—Initial Pre-65	6.25%	8.00%	7.50%	7.25%
Trend Rate—Initial Post-65	6.50%	8.50%	8.00%	7.50%
Trend Rate—Ultimate	4.75%	4.75%	4.75%	4.75%
Trend Rate—Ultimate Year Pre-65	2032	2032	2032	2032
Trend Rate—Ultimate Year Post-65	2032	2032	2032	2032
Expected Contribution	$ 0.0	$ 0.0	$ 0.0	$ 0.0

2024-2030 expense projections reflect the following:

-January 1, 2023 census data.
-APBO discount rate of 5.02% in fiscal 2024+, based on December 31, 2023 yield curve.
-Service Cost effective interest rate of 5.12% in fiscal 2024+, based on December 31, 2023 yield curve.
-Interest Cost effective interest rate of 4.91% in fiscal 2024+, based on December 31, 2023 yield curve.
-December 31, 2023 market assets provided by CMS.
-Other provisions, assumptions and methods are the same as those used for December 31, 2023 ASC 715 disclosures.

EXHIBIT A-67 (KKG-4)
IS CONFIDENTIAL AND
BEING FILED UNDER SEAL
WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Operations Support
($000)

Case No.: U-21806
Exhibit No.: A-68 (QAG-2)
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Witness: QAGuinn
Date: December 2024

Line No.	(a) Description	(b) Actual 12-Mos Ended 12/31/2023	(c) Projected 12-Mos Ending 10/31/2026
1	**Facilities**	**$ 7,795**	**$ 7,788**
	Labor	2,522	2,759
	Material	-	-
	Contractor	-	-
	Non-Labor Overhead	-	-
	Non-Labor Other	5,273	5,029
2	**Real Estate**	**$ 1,260**	**$ 991**
	Labor	894	810
	Material	-	-
	Contractor	-	-
	Non-Labor Overhead	-	-
	Non-Labor Other	366	182
3	**Supply Chain**	**$ 584**	**$ 746**
	Labor	49	52
	Material	-	-
	Contractor	-	-
	Non-Labor Overhead	-	-
	Non-Labor Other	535	694
4	**Total Operations Support O&M Expenses**	**$ 9,639**	**$ 9,525**
	Labor	3,464	3,621
	Material	-	-
	Contractor	-	-
	Non-Labor Overhead	-	-
	Non-Labor Other	6,174	5,905

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Operations Support
($000)

Case No.: U-21806
Exhibit No.: A-68 (QAG-2)
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Witness: QAGuinn
Date: December 2024

Line No.	Description	(a)	(b) Actual 12 Mos Ended Dec 31, 2023	(c) Base O&M for Merit & Inflation 12 Mos Ended Dec 31, 2023	(d) Merit & Inflation 12 Mos Ending Dec 31, 2024	(e) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	(f) Merit & Inflation 12 Mos Ending Dec 31, 2025	(g) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	(h) Merit & Inflation 10 Mos Ending Oct 31, 2026	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending Oct 31, 2026
					(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	**Facilities**		**$ 7,795**	**$ 1,387**	**$ -**	**$ 1,429**	**$ -**	**$ 1,518**	**$ -**	**$ (7)**	**$ 7,788**
	Labor		2,522	1,387	-	1,429	-	1,518	-	238	2,759
	Material		-	-	-	-	-	-	-	-	-
	Contractor		-	-	-	-	-	-	-	-	-
	Non-Labor Overhead		-	-	-	-	-	-	-	-	-
	Non-Labor Other		5,273	-	-	-	-	-	-	(244)	5,029
2	**Real Estate**		**$ 1,260**	**$ 894**	**$ -**	**$ 810**	**$ -**	**$ 810**	**$ -**	**$ (268)**	**$ 991**
	Labor		894	894	-	810	-	810	-	(84)	810
	Material		-	-	-	-	-	-	-	-	-
	Contractor		-	-	-	-	-	-	-	-	-
	Non-Labor Overhead		-	-	-	-	-	-	-	-	-
	Non-Labor Other		366	-	-	-	-	-	-	(184)	182
3	**Supply Chain**		**$ 584**	**$ 49**	**$ -**	**$ 52**	**$ -**	**$ 52**	**$ -**	**$ 162**	**$ 746**
	Labor		49	49	-	52	-	52	-	3	52
	Material		-	-	-	-	-	-	-	-	-
	Contractor		-	-	-	-	-	-	-	-	-
	Non-Labor Overhead		-	-	-	-	-	-	-	-	-
	Non-Labor Other		535	-	-	-	-	-	-	159	694
4	**Total Operations Support O&M Expenses**		**$ 9,639**	**$ 2,330**	**$ -**	**$ 2,290**	**$ -**	**$ 2,379**	**$ -**	**$ (113)**	**$ 9,525**
	Labor		3,464	2,330	-	2,290	-	2,379	-	156	3,621
	Material		-	-	-	-	-	-	-	-	-
	Contractor		-	-	-	-	-	-	-	-	-
	Non-Labor Overhead		-	-	-	-	-	-	-	-	-
	Non-Labor Other		6,174	-	-	-	-	-	-	(270)	5,905

Notes

	12-Mo Ending 2024	12-Mo Ending 2025	10-Mo Ending 2026
	0.0%	0.0%	0.0%
Number of months in the period	12	12	10
Pro-rated inflation rate	0.0%	0.0%	0.0%

Michigan Public Service Commission
Consumers Energy Company
Detailed List of Projected Gas Capital Expenditures
Operations Support
(000's)

Case No: U-21806
Exhibit No: A-69 (QAG-3)
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Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Period*			Projected Test Year*
		12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026
Line No.		Gas	Gas	Gas	Gas	Gas
1	**Other Equipment**	**175**	**660**	**489**	**1,148**	**652**
2	Wellness Equip	-	51	37	88	50
3	Computer Equipment	0	8	6	14	8
4	Print Equipment	-	43	32	75	42
5	Real Estate Tools & Equipment	-	10	7	18	10
6	Supply Chain Tools & Equipment	113	506	375	881	500
7	Facilities Tools	61	42	31	73	42
8	**Emergent Repairs**	**733**	**702**	**760**	**1,463**	**1,939**
9	Asset Preservation - Unplanned Repair	733	702	760	1,463	1,939
10	**Asset Replacement**	**6,063**	**10,214**	**6,807**	**17,021**	**7,838**
11	Statewide Paving	628	3,090	2,865	5,955	3,008
12	Statewide Roofing	676	1,337	1,535	2,872	2,097
13	Statewide Mechanical/Electrical	4,566	5,552	1,999	7,551	2,187
14	Statewide Elevators	138	55	313	368	445
15	Furniture	55	180	95	275	102
16	**New Construction**	**5,526**	**8,092**	**13,078**	**21,170**	**7,199**
17	Lansing Service Center	1,501	1,858	13,078	14,937	7,199
18	Hastings Service Center	4	114	-	114	-
19	Gas City Training	471	31	-	31	-
20	EIRP GCON	3,550	6,089	-	6,089	-
21	**Renovations**	**1,153.9**	**3,710**	**7,737**	**11,446**	**3,280**
22	Kalamazoo Service Center	407	3,358	7,591	10,949	3,080
23	Parnall Renovations (P1-3)	353	-	-	-	-
24	Jackson Dispatch	302	156	-	156	-
25	Midland Building	13	-	-	-	-
26	EV Infrastructure	79	196	145	341	199
27	Miscellaneous	**2,382**	**1,571**	**-**	**1,571**	**-**
28	**Total Capital**	**16,032**	**24,948**	**28,871**	**53,819**	**20,907**

**The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level.*

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Facilities & Shared Services
(000's)
5 Year Historical

Case No: U-21806
Exhibit No: A-69 (QAG-3)
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Date: December 2024

Line No.	(a)	(b) Historical Year 12 Mos Ended 12/31/2019	(c) Historical Year 12 Mos Ended 12/31/2020	(d) Historical Year 12 Mos Ended 12/31/2021	(e) Historical Year 12 Mos Ended 12/31/2022	(f) Historical Year 12 Mos Ended 12/31/2023
		Gas	Gas	Gas	Gas	Gas
1	**Other Equipment**	**301**	**287**	**604**	**192**	**175**
2	Wellness Equip	137	2	11	20	-
3	Computer Equipment	7	-	-	8	0
4	Print Equipment	-	75	15	-	-
5	Real Estate Tools & Equipment	-	24	49	17	-
6	Supply Chain Tools & Equipment	140	163	529	147	113
7	Facilities Tools	18	24	-	-	61
8	**Emergent Repairs**	**2,365**	**1,606**	**2,728**	**1,955**	**733**
9	Asset Preservation - Unplanned Repair	2,365	1,606	2,728	1,955	733
10	**Asset Replacement**	**7,475**	**7,482**	**4,252**	**7,886**	**6,063**
11	Statewide Paving	2,983	5,251	2,111	3,083	628
12	Statewide Roofing	1,538	848	846	1,915	676
13	Statewide Mechanical/Electrical	1,923	1,146	953	2,566	4,566
14	Statewide Elevators	297	11	183	22	138
15	Furniture	734	225	159	299	55
16	**New Construction**	**22**	**860**	**734**	**10,521**	**5,526**
17	Lansing Service Center	14	850	76	262	1,501
18	Hastings Service Center	8	2	8	2	4
19	Gas City Training	-	8	649	8,836	471
20	EIRP GCON	-	-	-	1,421	3,550
21	**Renovations**	**132**	**100**	**164**	**2,777**	**1,154**
22	Kalamazoo Service Center	125	1	21	153	407
23	Parnall Renovations (P1-3)	6	99	143	2,286	353
24	Jackson Dispatch	-	-	-	246	302
25	Midland Building	-	-	-	72	13
26	EV Infrastructure				21	79
27	Other not included in A-71 (QAG-3)	4,043	4,209	5,226	1,796	2,382
28	**Total Capital**	**14,338**	**14,544**	**13,708**	**25,127**	**16,032**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Facilities & Shared Services
(000's)
Lansing/Hastings/Kalamazoo Service Centers - Current Construction Cost

Case No: U-21806
Exhibit No: A-69 (QAG-3)
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Witness: QAGuinn
Date: December 2024

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Line No.		**Location**	**Type of Operations**	**Electric Allocation**	**Gas Allocation**	**Total Historical Cost**	**Allocated Electric Historical Cost**	**Allocated Gas Historical Cost**	**Total Plan Cost 2024***	**Allocated Electric Cost 2024**	**Allocated Gas Cost 2024**	**Total Plan Cost 2025***	**Allocated Electric Cost 2025**	**Allocated Gas Cost 2025**	**Total Plan Cost 2026***	**Allocated Electric Cost 2026**	**Allocated Gas Cost 2026**	**Total Costs**
1	New Construction	Lansing SC	Common	54%	46%	$5,854	$3,178	$2,676	$4,077	$2,219	$1,858	$31,074	$16,911	$14,164	$15,297	$8,325	$6,973	$56,302
2	New Construction	Hastings SC	Common	54%	46%	$55	$30	$25	$250	$136	$114	$0	$0	$0	$0	$0	$0	$305
3	Renovations	Kalamazoo SC	Common	54%	46%	$1,689	$917	$772	$7,367	$3,997	$3,358	$20,586	$11,170	$9,383	$5,312	$2,882	$2,421	$34,953

4	(000's)	**Location**		**Total Plan Cost 2024***	**Total Plan Cost 2025***	**Total Plan Cost 2026***
5	New Construction	Lansing SC	Master Planning			
6			Programming			
7			Land Acquisition			
8			Engineering	$514		
9			Construction	$3,562	$29,674	$14,849
10			Furnishings		$1,400	$448
11			Commissioning			
12	New Construction	Hastings SC	Master Planning			
13			Programming			
14			Land Acquisition	$250		
15			Engineering			
16			Construction			
17			Furnishings			
18			Commissioning			
19	New Construction	Kalamazoo SC	Master Planning			
20			Programming			
21			Land Acquisition			
22			Engineering	$1,473	$507	
23			Construction	$5,893	$20,079	$4,742
24			Furnishings			$570
25			Commissioning			
26		**Location**		**Total Plan Cost 2024**	**Total Plan Cost 2025**	**Total Plan Cost 2026**

**The Company fully plans to perform the projects included in these cost projections, but the projections do not incorporate a specific confidence level.*

Line No.	(a)	(b)	(c)	(d)
1	**Project Name**	**Internal Approval**	**Has a Business Case**	**Explanation**
2	Lansing Service Center	YES	YES	
3	Hastings Service Center	YES	YES	
4	EIRP GCON	YES	YES	
5	Kalamazoo Service Center	YES	YES	
6	Jackson Dispatch	YES	NO	Renovation for the Gas Dispatch improves communication between Dispatch personnel and Company crews (especially during storm events) resulting in improved restoration response, gas leak response, and the like. Improved communication also reduces the risk of safety incidents for both Company crews and the public.
7	EV Infrastructure	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.
8	Statewide Paving	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.
9	Statewide Roofing	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.
10	Statewide Mechanical/Electrical	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.
11	Statewide Elevators	YES	NO	Internal funding approval. There is no formal business case but there is documented need for work as discussed in testimony.

Service Center Projects

Plan Summaries

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CMS ENERGY

Lansing Service Center

Plan Summary

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Lansing Service Center – Health Assessment

Facility Assessment - Lansing Service Center					
Location	Lansing	Maximum Possible Points (80)	Servicable > 48 Points	Poor < 48 Points	Good > 64 Points
Zone	MMOM				
Safety					
Compatible Use	0	5	3	2	4
Site Conditions	3	5	3	2	4
Traffic/Site Flow	1	5	3	2	4
Environmental Hazard	1	5	3	2	4
Quality					
Branding	2	5	3	2	4
Workplace Efficiency	3	5	3	2	4
Years since last major systems upgrade	0	5	3	2	4
Cost					
Facility Operating Costs	4	5	3	2	4
Non Facility Cost Impact	4	5	3	2	4
Space Optimization	3	5	3	2	4
Delivery					
Drive Time	3	5	3	2	4
Customer Response	4	5	3	2	4
Sustainability	1	5	3	2	4
Morale					
Employee Pride	2	5	3	2	4
Retention	3	5	3	2	4
Wellness	5	5	3	2	4
Total	***39***	***80***	***48***	***32***	***64***

Lansing Service Center – Health Assessment Scoring Criteria

Safety (20 Points)	Comments	Pro	Con	Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Compatible Use	Use of property is compatible with adjoining properties and surrounding area.	Industrial zoning and use	Residential use, retail use, criminal activity	Residential zoning, high crime area	Residential zoning	Mixed Commercial / Residential zoning	Commercial zoning for Service Centers, mixed Commercial / Industrial zoning for non-Service Centers	Industrial zoning for Service Centers, Commercial zoning for non-Service Centers	Industrial zoning for Service Centers, Central Business District zoning for non-Service Centers
Site Conditions	Physical condition of site	Full utilities, good paving, fencing, drainage	No utilities, poor paving, fencing, drainage	Site not adequate to support operational requirements, located in flood plain,	Site not adequate to support operational requirements	significant upgrades, such as storm water detention, fire water, potable water, sanitary sewer, paving, etc.	Site in serviceable condition with full utilities or good condition with partial utilities	Site in good condition, full utilities	Site in good condition with undeveloped space to accommodate future growth
Traffic/Site Flow	Road network, site access drive, vehicle turning space	Close to highway, access from two roads, space for truck trailer to pull off road, one way gates	Secondary road, no truck pull off space at gate, two way gates, insufficient turning space	Unimproved road frontage / site traffic flows crossing	Non Class A road frontage / Site heavy traffic and light traffic flows crossing	with impediments, railroad tracks, intersections, etc. / Site traffic flows crossing	Class A road frontage / Site traffic flows mixed	Class A road frontage with secondary frontage / Site traffic flows separated	with secondary frontage and nearby highway access / Site traffic flows separated
Environmental Hazard	Environmental hazards	LEED certification, no environmental hazards	Former MGP site, soil contamination, abandoned underground fuel tanks, abandoned transformer storage, asbestos fire proofing, asbestos duct wrap, asbestos pipe wrap, lead paint,	Immediate hazards to employees present during normal use of site	Hazardous materials present, with reoccurring or continuous exposure hazard, former MGP site, current 201 site	Hazardous materials present in manageable form, former MGP site, current 201 site	Hazardous materials present in manageable form	No environmental impacts, hazardous materials abated or encapsulated	LEED Certified facility with no environmental impacts

Quality (15 Points)	***Employee/Customer Engagement***	Pro	Con	Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Branding	Projects positive image to community and potential employees	Well cared for facility, curb appeal, neat landscaping, coordinated site signage	Dilapidated facility, dated appearance, overgrown landscaping, mismatched site signage	damaged or deteriorated structures, landscape materials overgrown or absent, failed pavement, etc.	Structures deteriorated, landscape materials overgrown or absent, failing paving, no signage	Structures poorly maintained, landscape materials overgrown or absent, poor signage	for, landscape materials in serviceable condition, uncoordinated signage	Structures well cared for, landscape materials in good condition, coordinated signage	New facility, landscape materials in good condition, coordinated signage
Workplace Efficiency	Space is fully utilized	Space provided for all operational functions, space size meets needs, proper inventory stored	Space not provided for all operational functions, space oversized, space not fully utilized, unused materials (junk) stored	Space inadequate for intended occupancy	Hard wall offices, empty or vacant spaces	Hard wall offices, fully utilized	Mix of hard wall offices and systems furniture, fully utilized	Modular systems furniture, fully utilized	Flexible, open and collaborative workspaces, modular systems furniture, fully utilized
Years since last major systems upgrade	Condition of facility is code compliant, building systems are within normal operational life cycle and supports working environment	New construction or recently completed full renovation	Building old and unrenovated or only minimal or partial renovation work completed	initial construction or last major systems upgrade	initial construction or last major systems uprade	initial construction or last major systems uprade	initial construction or last major systems uprade	initial construction or last major systems uprade	initial construction or last major systems uprade

Lansing Service Center – Health Assessment Scoring Criteria

Cost (15 Points)		Pro	Con	Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Facility Operating Costs	O&M costs to operate and maintain facility	Cost per square foot for facility less than statewide average cost per square foot ($5.31)	Cost per square foot for facility more than statewide average cost per square foot ($5.31)	costs greater than $10.00 per square foot	costs between $8.00 to $10.00 per square foot	costs between $7.25 to $7.99 per square foot	costs between $7.00 to $7.24 per square foot	costs between $5.75 to $6.99 per square foot	Combined operating costs less than $5.75 per square foot
Non Facility Cost Impact	O&M cost impacts to operations	Building correct size, centrally located within customer base area, able to accommodate necessary materials, able to maneuver onsite	Building too large, eccentrically located within customer base area, unable to accommodate necessary materials, difficult to maneuver onsite	Building eccentrically located within service territory, inadequate space	Building eccentrically located within service territory, underutilized space	Building eccentrically located within service territory	Building centrally located within service territory	Building accommodates operational needs, centrally located within service territory	Building accommodates operational need, space utilized efficiently, centrally located within service territory
Space Optimization	Reduce excess square footage	Space fully utilized, space utilized efficiently	Space under utilized, space utilized inefficiently, indoor parking area	Building vacant	Building partially occupied or partially vacant	Building occupied inefficiently, includes IPA	Building fully occupied, includes IPA	Building fully occupied, no IPA	occupied, no IPA, includes cold storage

Delivery (15 Points)	Customer Service	Pro	Con	Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Drive Time	Service territory area of proper size	Centrally located within service area(s), drive time balanced across territory and within targeted limits	Eccentrically located within service area(s), drive time unbalanced across territory and/or exceeds targeted limits	service territory and size of service territory allows drive time >1:20 Gas and >1:30 Electric	service territory and size of service territory allows drive time < 1:20 Gas and <1:30 Electric	service territory and size of service territory allows drive time < 1:10 Gas and <1:15 Electric	service territory and size of service territory allows drive time < 1:00 Gas and <1:00 Electric	service territory and size of service territory allows drive time < 0:50 Gas and <0:45 Electric	service territory and size of service territory allows drive time < 0:40 Gas and <0:30 Electric
Customer Response	Meets needs of customers	Customer response time metrics fall below targets	Customer response times exceed targets	response times meet target <90% of time, Electric CAIDI >215 minutes	response times meet target >90% of time, Electric CAIDI <215 minutes	response times meet target >95% of time, Electric CAIDI <195 minutes	response times meet target >97% of time, Electric CAIDI <180 minutes	response times meet target >98% of time, Electric CAIDI <165 minutes	response times meet target >99% of time, Electric CAIDI <150 minutes
Sustainability	Facility incproprates reduced energy utiliztion and minimizes environmental impact	Facility constructed in accordance with recent Energy Codes, includes onsite stormwater treatment, Green building certification	Facility constructed with no insulation, utilizes enegy intensive equipment, no onsite storm water treatment	Minimal roofing insulation	Upgraded roofing insulation	Upgraded roofing insulation and windows	Upgraded roofing insulation, windows and building envelope	insulation, windows, and building envelope with onsite storm water treatment	LEED Certified (or higher LEED rated) facility

Lansing Service Center – Health Assessment Scoring Criteria

Morale (15 Points)	Employee Wellness	Pro	Con	Score 0 Does not satisfy criteria	Score 1 Does not satisfy most listed criteria	Score 2 Does not satisfy some listed criteria	Score 3 Satisfies minimal criteria	Score 4 Satisfies most listed criteria	Score 5 Satisfies all listed criteria
Employee Pride	Employees are engaged	Employee engagement scores > company average	Employee engagement scores < company average	Deteriorated facility	Deteriorated or dated facility with limited amenities	Dated facility with minimal amenities	Dated facility with full amenities and onsite parking	Modern facility with full amenities	Modern facility with full amenities, onsite parking
Retention	Facilities located in a desirable area, space is attractive to Millennials and supports millennial work styles	Downtown location, local amenities available, space supports varied work styles	Remote location, few local amenities, fixed work space	Remote location, no local amenities	some amenities available within 20 minutes driving distance	Remote location, amenities available within 20 minutes driving distance	Remote location, amenities available within 15 minutes driving distance	Diverse location, amenities available within 10 minutes driving distance	Diverse location, amenities available within walking distance
Wellness	Wellness facilities	Wellness room, space for trainer, drinking fountain, shower facilities nearby, space for wellness classes, well maintained exercise equipment, mirrors, lockers	Wellness room combined with non-compatible uses (i.e.: conference room), aged exercise equipment, poorly maintained exercise equipment, remote shower facilities	No shower, drinking fountain, Wellness or Nursing Mother Room, no additional space available	Shower and drinking fountain, no Wellness or Nursing Mother Room, no additional space available	Wellness Room or Nursing Mother Room, shower and drinking fountain, no additional space available	Nursing Mother Room, shower and drinking fountain, with space available to add Wellness or NMR	Wellness Room and Nursing Mother room, shower and drinking fountain, with space available for Trainer	Wellness room, Trainer room, Nursing Mother Room, shower and drinking fountain nearby

Lansing Service Center – Alternatives Matrix

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Alternative Scenario Evaluation Matrix - Lansing Service Center Major Systems Upgrade

	Weight	Build on New Site Score	Renov. Existing Score	Do Nothing Score	Score	COMMENTS
Section 1 - Affordable (50%)						
Operating cost per square foot below statewide average	40%	4.0	3.0	2.0		Current facility operating cost for Lansing is $6.97 per square foot, versus statewide average operating cost of $5.31 per square foot.
Construction cost	10%	1.0	4.0	5.0		
Section 1 - Scenario Average Weighted Score Total (Best = 5):		1.7	1.6	1.3	0.0	
Section 2 - Safe (25%)						
Hazardous Material Abatement (asbestos, lead paint)	5.0%	4.0	3.0	1.0		
Site located outside high crime area	5.0%	4.0	1.0	1.0		
Pedestrian traffic route separated from truck traffic route	2.5%	4.0	1.0	1.0		
Site located outside defined FEMA 100 year flood elevation	10.0%	4.0	1.0	1.0		Current location is 3' below FEMA 100 year flood elev.
Site soils not impacted by previous use (Manufactured Gas Plant)	2.5%	4.0	1.0	1.0		Current location is former Manufactured Gas Plant site
Section 2 - Scenario Average Score Total (Best = 5):		1.0	0.4	0.3	0.0	
Section 3 - Reliable (17.5%)						
Overall score above 72 as measured by Facilites Scorecard	2.5%	4.0	3.0	1.0		Current overall facility score for Lansing is 39
Building size matches operational needs	5.0%	4.0	2.0	2.0		Building fully occupied currently (pre COVID-19)
Improve CAIDI Score > 3%	4.0%	4.0	1.0	1.0		
On Premise start times improved by 5 to 10 minutes	5.0%	4.0	2.0	1.0		Improved material flow and vehicle loading
Drive through vehicle repair bays	2.5%	4.0	2.0	2.0		Improved vehicle repair time, reduced vehicle damage
Section 3 - Scenario Weighted Score Total (Best = 5):		0.6	0.3	0.2	0.0	
Section 4 - Clean (7.5%)						
LEED V4.1 Certification	2.5%	4.0	3.0	1.0		
Stormwater detention and treatment	2.5%	4.0	1.0	1.0		Stormwater currently direct discharge to Grand River
Onsite solar power generation	1.0%	4.0	1.0	1.0		
Section 3 - Scenario Weighted Score Total (Best = 5):		0.2	0.1	0.1	0.0	
TOTAL WEIGHTED VALUE SCORE: (BEST = 5)	100%	3.5	2.4	1.8	0.0	

Lansing Service Center – Alternatives Matrix Criteria

Safe
Hazardous Material Abatement (asbestos, lead paint)
Site located outside high crime area
Pedestrian traffic route separated from truck traffic route
Site located outside defined FEMA 100 year flood elevation
Site soils not impacted by previous use
Affordable
Operating cost per square foot below statewide average
Construction cost
Reliable
Overall score above 72 as measured by Facilites Scorecard
Building size matches operational needs
Improve CAIDI Score > 3%
On Premise start times improved by 5 to 10 minutes
Drive through vehicle repair bays
Clean
LEED V4.1 Certification
Stormwater detention and treatment
Onsite solar power generation
Non-Monetary Considerations
Other Risks & Barriers
Regulatory
Technical/Engineering
Aesthetics
People
Process
Technology
Customer Requirements
Real Estate
Municipality Requirements

New Lansing Service Center – Potential Locations

Property Details	Site A	Site B	Site C
Site Address	6964 N. Canal Rd. Dimondale, MI 48821	401 N. Verlinden Ave. Lansing, MI 48915	S. Waverly Rd & W. Miller Rd. Lansing, MI 48911
County	Eaton	Ingham	Ingham
Municipality	Windsor Township	City of Lansing	City of Lansing
Acreage	77.67	57	50

New Lansing Service Center – Potential Locations

Site Characteristics	Site A	Site B	Site C
Site Address	6964 N. Canal Rd. Dimondale, MI 48821	401 N. Verlinden Ave. Lansing, MI 48915	S. Waverly Rd. & W. Miller Rd. Lansing, MI 48911
Internal CE Security Assessment	Low Risk	High Risk	Medium Risk
Distance to Highways	Less than 1 mile to I-96	¼ Mile from M43; 2 miles to I-496	1.5 miles to I-96
Zoning	✓ M1 Industrial	✓ Industrial	✗ Residential
3 Phase	✓ Yes	✓ Yes	✗ No
Natural Gas	✓ Yes	✓ Yes	✓ Yes
Water	✗ No; water main extension pending	✓ Yes	✓ Yes
Sewer	✓ Yes	✓ Yes	✓ Yes
Fiber	✗ No	✗ No	✗ No
Wetlands Identified	Yes; 60 usable acres	No; 57 usable acres	Yes; 40 usable acres
Known Environmental Contamination	✓ No	✗ Yes	✓ No

New Lansing Service Center – Potential Locations – Gas / Electric Customer Response Time Comparisons

Electric work order x minutes Number of Work Orders and Time			
Verlinden Site Option	**Electric**		
10 minutes	17,984	179,840	
20 minutes	63,792	1,275,840	
30 minutes	15,949	478,470	
40 minutes	972	38,880	
50 minutes			
Total	98,697	1,973,030	Best Electric but worst Gas
Waverly Site Option	**Electric**		
10 minutes	7,505	75,050	
20 minutes	52,207	1,044,140	
30 minutes	31,058	931,740	
40 minutes	7,841	313,640	
50 minutes	86	4,300	
Total	98,697	2,368,870	Worst Electric but best Gas
Canal Site Option	**Electric**		
10 minutes	8,464	84,640	
20 minutes	56,349	1,126,980	
30 minutes	28,126	843,780	
40 minutes	5,742	229,680	
50 minutes	16	800	
Total	98,697	2,285,880	Mid for both Electric and Gas

Gas work order x minutes Number of Work Orders and Time			
Verlinden Site Option	**Gas**		
10 minutes	41,742	417,420	
20 minutes	62,020	1,240,400	
30 minutes	22,865	685,950	
40 minutes	1,939	77,560	
50 minutes			
Total	128,566	2,421,330	Worst Gas but best Electric
Waverly Site Option	**Gas**		
10 minutes	26,982	269,820	
20 minutes	77,463	1,549,260	
30 minutes	19,380	581,400	
40 minutes	4,741	189,640	
50 minutes			
Total	128,566	2,590,120	Best Gas but worst Electric
Canal Site Option	**Gas**		
10 minutes	21,801	218,010	
20 minutes	85,674	1,713,480	
30 minutes	17,453	523,590	
40 minutes	3,638	145,520	
50 minutes			
Total	128,566	2,600,600	Mid for both Gas and Electric

New Lansing Service Center – Potential Locations within City of Lansing

401 N. Verlinden Ave. Lansing, MI 48915

Positives:

- Low purchase price
- Potential tax incentives available
- Utilities available

Limitations:

- Environmental concerns
- Unknown abandon utilities and tunnels under surface
- LBWL substation on site along with HVD line but unable to serve ourselves with electric
- Fiber would need to be ran to site
- Medium-risk security assessment needed

S. Waverly Rd. & W. Miller Rd. Lansing, MI 48911

Positives:

- Potential assistance with site preparation
- Potential assistance with demo of asbestos

Limitations:

- Wetlands and possibly not enough usable property
- Potentially unable to have a drive on S. Waverly due to hill and high speeds coming northbound on Waverly - both drives would have to be off of W. Miller Rd
- Length of time to potentially acquire site
- Demo of houses with asbestos
- Probably unable to serve ourselves with electric
- Fiber is currently some distance away – would need to be ran to site
- Currently zoned residential and would need to be rezoned to light industrial
- Medium-risk security assessment needed
- Unknown purchase price

New Lansing Service Center – Potential Locations within City of Lansing

South of Grand River, Ave.

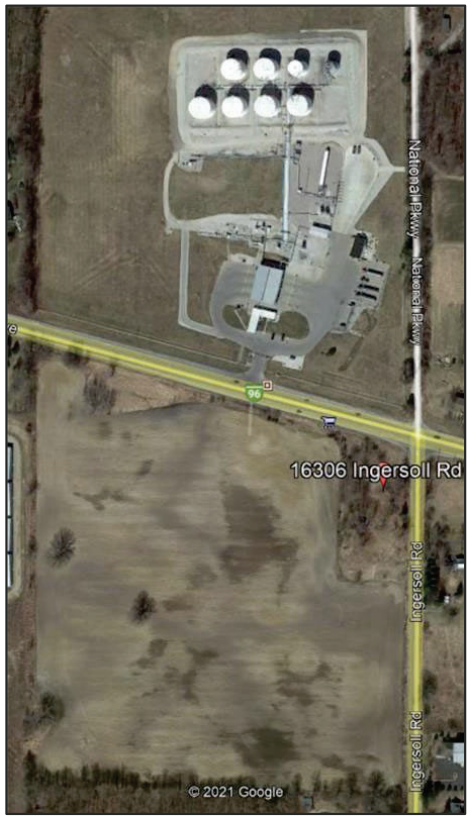
Positives:

- Utilities available (Water & Sewer)

Limitations:

- Fuel station across the street
- Possible wetlands
- Further north
- Lots of traffic on road

*No other data was collected regarding this location



New Lansing Service Center Potential Location

401 N. Verlinden Ave. Lansing - Site Characteristics

57 acres

Response Time:	• 87% of reported outages are reached in 30 minutes timeframe • 100% of reported outages are reached within 45 minutes
Ease of Travel:	CE Operations: • Difficulty with turning and maneuvering trucks and trailers through city streets and blocks • Travel impediment due to foot and bike traffic, CATA bus stops, railroad crossing and street parking in residential areas • Difficult to access highways through residential areas: 2 miles to I-496
Security:	• **CE Security Risk Assessment Rating – HIGH** • Crimes occurring within 1-mile radius of parcel within 12/26/19-01/23/20: Assault – 15; Weapon Offenses – 6; Larceny – 6; Vandalism – 4; Burglary – 4; Motor Vehicle Theft – 3; Robbery – 1 • 74 sex offenders in registry within 1-mile radius
Wetlands identified:	• No identified wetlands on the parcel
Environmental concerns:	• Significant concern regarding existing contamination and abandoned underground utility facilities on the property. Further due diligence would be required if site is selected to evaluate impact to service center construction and operations.

New Lansing Service Center Potential Location

S. Waverly & W. Miller Rd, Lansing - Site Characteristics

33 usable acres

Response Time:	• 88% of reported outages are reached in the 30 minutes • 100% of reported outages are reached within 50 minutes
Ease of Travel:	CE Operations: • Difficulty with turning and maneuvering trucks and trailers through city streets and blocks • Travel impediment due to foot and bike traffic, CATA bus stops and street parking in residential areas • Difficult to access highways through residential areas: 1.5 miles to I-96
Security:	• **CE Security Risk Assessment Rating – MEDIUM** • Crimes occurring within 1-mile radius of parcel within 12/26/19-01/23/20: Assault – 6; Vandalism – 1; Larceny – 1; Motor Vehicle Theft – 1 • 16 sex offenders in registry within 1-mile radius
Wetlands identified:	• The State's National Wetland Inventory map indicates 17 acres of regulated wetlands of the 50-acre parcel • CE would not be able to use 17 acres without costly wetland mitigation. Would limit or possibly eliminate future expansion on site.
Environmental concerns:	• LEAP reports asbestos abatement needed prior to demolition of existing houses on parcel • CE Environmental reports existing contaminated site on the adjacent property to the east

New Lansing Service Center Potential Location

6964 N. Canal Rd, Dimondale - Site Characteristics

60 usable acres

Response Time:	• 91% of reported outages are reached in the 30 minute timeframe • 100% of reported outages are reached within 45 minutes
Ease of Travel:	CE Operations: • Located in the industrial area of Windsor Commerce Parkway. Roads and intersections provide for wider turns for maneuvering trucks and trailers • Access to highways through commercial areas: 0.75 miles to I-96; 1.35 miles to I-69 • Limited foot and bike traffic and no parking on roads
Security:	• **CE Security Risk Assessment Rating – LOW** • Crimes occurring within 1-mile radius of parcel within 12/26/19-01/23/20: Assault – 0 • 4 sex offenders in registry within 1-mile radius • High police presence due to Michigan State Police within 0.6 miles from parcel
Wetlands identified:	• The State's National Wetland Inventory map indicates 7.29 acres of regulated wetlands on the 77.67-acre parcel • Property size allows for CE use to be designed to avoid wetland areas and allow for future expansion.
Environmental concerns:	• No known environmental concerns

New Lansing Service Center – Electric Benefits

New Lansing Service Center - Electric Customer Benefits

Electric work order x minutes
Number of Work Orders x Travel Time

Canal - New Site	Electric	WO x Min.
10 minutes	8,464	84,640
20 minutes	56,349	1,126,980
30 minutes	28,126	843,780
40 minutes	5,742	229,680
50 minutes	16	800
Total	98,697	2,285,880

Willow - Current Site	Electric	WO x Min.
10 minutes	2,142	21,420
20 minutes	58,784	1,175,680
30 minutes	31,496	944,880
40 minutes	6,239	249,560
50 minutes	36	1,800
Total	98,697	2,393,340

2018 Electric Outages	50,135	Customers
2019 Electric Outages	56,670	Customers
Total Electric Outages	106,805	Customers
Avg Annual Outages	53,403	Customers
Difference:	107,460	Minutes reduction in travel time to customer sites compared to Willow Road
	4.5%	Reduction in travel time to customer sites compared to Willow Road
Cost Savings:	$185,906	Productivity recaptured annually based on $3.46 per minute per employee
Electric CAIDI Improvement:	53,730	Annual reduction in travel minutes
	4,478	Monthly reduction in travel minutes

New Lansing Service Center – Gas Benefits

New Lansing Service Center - Gas Customer Benefits

Gas work order x minutes
Number of Work Orders x Travel Time

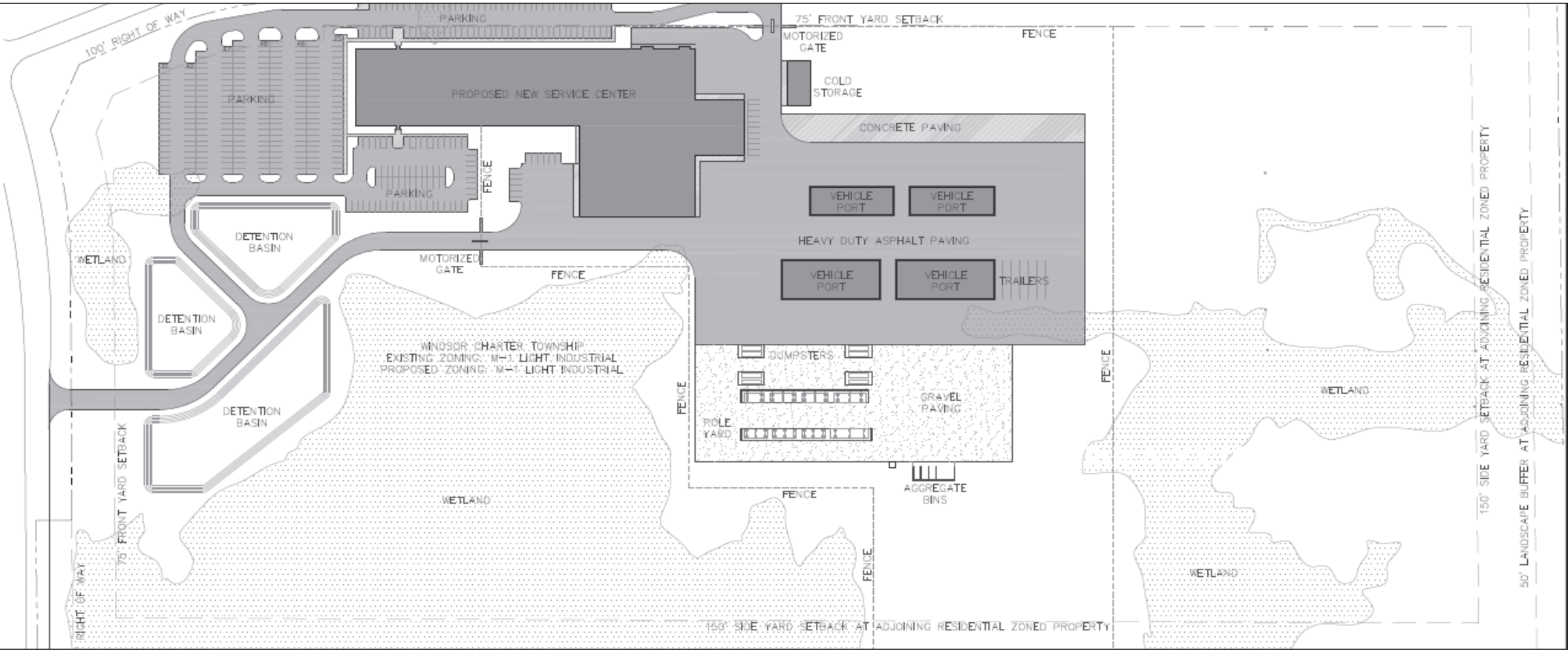
Canal - New Site	Gas	WO x Min.
10 minutes	21,801	218,010
20 minutes	85,674	1,713,480
30 minutes	17,453	523,590
40 minutes	3,638	145,520
50 minutes		
Total	128,566	2,600,600

Willow - Current Site	Gas	Adjust.
10 minutes	25,726	257,260
20 minutes	62,260	1,245,200
30 minutes	30,560	916,800
40 minutes	9,489	379,560
50 minutes	531	26,550
Total	128,566	2,825,370

Difference:	**224,770**	**Minutes reduction in travel time to customer sites compared to Willow Road**
	8.0%	**Reduction in travel time to customer sites compared to Willow Road**
Cost Savings:	**$309,059**	**Productivity recaptured annually based on $2.75 per minute per employee**

Gas Response Time Improvement: 224,770

Lansing Service Center – Conceptual Site Plan



Hastings Service Center

Plan Summary

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Hastings Service Center – Health Assessment

Facility Assessment - Hastings Service Center					
Location	Hastings	Maximum Possible Points (80)	Serviceable > 48 Points	Poor < 48 Points	Good > 64 Points
Zone	SWOM				
Safety					
Compatible Use	4	5	3	2	4
Site Conditions	4	5	3	2	4
Traffic/Site Flow	2	5	3	2	4
Environmental Hazard	3	5	3	2	4
Quality					
Branding	3	5	3	2	4
Workplace Efficiency	3	5	3	2	4
Years since last major systems upgrade	1	5	3	2	4
Cost					
Facility Operating Costs	0	5	3	2	4
Non Facility Cost Impact	4	5	3	2	4
Space Optimization	2	5	3	2	4
Delivery					
Drive Time	4	5	3	2	4
Customer Response	3	5	3	2	4
Sustainability	3	5	3	2	4
Morale					
Employee Pride	1	5	3	2	4
Retention	3	5	3	2	4
Wellness	1	5	3	2	4
Total	***41***	***80***	***48***	***32***	***64***

Hastings Service Center – Health Assessment Scoring Criteria

Safety (20 Points)	**Score 0** Does not satisfy criteria	**Score 1** Does not satisfy most listed criteria	**Score 2** Does not satisfy some listed criteria	**Score 3** Satisfies minimal criteria	**Score 4** Satisfies most listed criteria	**Score 5** Satisfies all listed criteria
Compatible Use	Residential zoning, high crime area	Residential zoning	Mixed Commercial / Residential zoning	Commercial zoning for Service Centers, mixed Commercial / Industrial zoning for non-Service Centers	Mixed Commercial / Industrial zoning for Service Centers, Commercial zoning for non-Service Centers	Industrial zoning for Service Centers, Central Business District zoning for non-Service Centers
Site Conditions	Site not adequate to support operational requirements, located in flood plain,	Site not adequate to support operational requirements	significant upgrades, such as storm water detention, fire water, potable water, sanitary sewer, paving, etc.	Site in serviceable condition with full utilities or good condition with partial utilities	Site in good condition, full utilities	Site in good condition with undeveloped space to accommodate future growth
Traffic/Site Flow	Unimproved road frontage / site traffic flows crossing	Non Class A road frontage / Site heavy traffic and light traffic flows crossing	with impediments, railroad tracks, intersections, etc. / Site traffic flows crossing	Class A road frontage / Site traffic flows mixed	Class A road frontage with secondary frontage / Site traffic flows separated	Class A road frontage with secondary frontage and nearby highway access / Site traffic flows separated
Environmental Hazard	Immediate hazards to employees present during normal use of site	Hazardous materials present, with reoccurring or continuous exposure hazard, former MGP site, current 201 site	Hazardous materials present in manageable form, former MGP site, current 201 site	Hazardous materials present in manageable form	No environmental impacts, hazardous materials abated or encapsulated	LEED Certified facility with no environmental impacts
Quality (15 Points)	**Score 0**	**Score 1**	**Score 2**	**Score 3**	**Score 4**	**Score 5**
Branding	damaged or deteriorated structures, landscape materials overgrown or absent, failed pavement, etc.	Structures deteriorated, landscape materials overgrown or absent, failing paving, no signage	Structures poorly maintained, landscape materials overgrown or absent, poor signage	Structures well cared for, landscape materials in serviceable condition, uncoordinated signage	Structures well cared for, landscape materials in good condition, coordinated signage	New facility, landscape materials in good condition, coordinated signage
Workplace Efficiency	Space inadequate for intended occupancy	Hard wall offices, empty or vacant spaces	Hard wall offices, fully utilized	Mix of hard wall offices and systems furniture, fully utilized	Modular systems furniture, fully utilized	Flexible, open and collaborative workspaces, modular systems furniture, fully utilized
Years since last major systems upg	construction or last major systems upgrade	initial construction or last major systems uprade	initial construction or last major systems uprade	initial construction or last major systems uprade	initial construction or last major systems uprade	0-10 years since initial construction or last major systems uprade
Cost (15 Points)	**Score 0**	**Score 1**	**Score 2**	**Score 3**	**Score 4**	**Score 5**
Facility Operating Costs	costs greater than $10.00 per square foot	costs between $8.00 to $10.00 per square foot	costs between $7.25 to $7.99 per square foot	costs between $7.00 to $7.24 per square foot	costs between $5.75 to $6.99 per square foot	Combined operating costs less than $5.75 per square foot
Non Facility Cost Impact	Building eccentrically located within service territory, inadequate space	Building eccentrically located within service territory, underutilized space	Building eccentrically located within service territory	Building centrally located within service territory	Building accommodates operational needs, centrally located within service territory	Building accommodates operational need, space utilized efficiently, centrally located within service territory
Space Optimization	Building vacant	Building partially occupied or partially vacant	Building occupied inefficiently, includes IPA	Building fully occupied, includes IPA	Building fully occupied, no IPA	Building fully occupied, no IPA, includes cold storage

Delivery (15 Points)						
Drive Time	service territory and size of service territory allows drive time >1:20 Gas and >1:30 Electric	service territory and size of service territory allows drive time < 1:20 Gas and <1:30 Electric	Location within service territory and size of service territory allows drive time < 1:10 Gas and <1:15 Electric	service territory and size of service territory allows drive time < 1:00 Gas and <1:00 Electric	service territory and size of service territory allows drive time < 0:50 Gas and <0:45 Electric	service territory and size of service territory allows drive time < 0:40 Gas and <0:30 Electric
Customer Response	response times meet target <90% of time, Electric CAIDI >215 minutes	response times meet target >90% of time, Electric CAIDI <215 minutes	response times meet target >95% of time, Electric CAIDI <195 minutes	response times meet target >97% of time, Electric CAIDI <180 minutes	response times meet target >98% of time, Electric CAIDI <165 minutes	response times meet target >99% of time, Electric CAIDI <150 minutes
Sustainability	Minimal roofing insulation	Upgraded roofing insulation	Upgraded roofing insulation and windows	Upgraded roofing insulation, windows and building envelope	Upgraded roofing insulation, windows, and building envelope with onsite storm water treatment	LEED Certified (or higher LEED rated) facility
Morale (15 Points)	**Score 0**	**Score 1**	**Score 2**	**Score 3**	**Score 4**	**Score 5**
Employee Pride	Deteriorated facility	Deteriorated or dated facility with limited amenities	Dated facility with minimal amenities	Dated facility with full amenities and onsite parking	Modern facility with full amenities	Modern facility with full amenities, onsite parking
Retention	Remote location, no local amenities	some amenities available within 20 minutes driving distance	Remote location, amenities available within 20 minutes driving distance	Remote location, amenities available within 15 minutes driving distance	Diverse location, amenities available within 10 minutes driving distance	Diverse location, amenities available within walking distance
Wellness	No shower, drinking fountain, Wellness or Nursing Mother Room, no additional space available	Shower and drinking fountain, no Wellness or Nursing Mother Room, no additional space available	Wellness Room or Nursing Mother Room, shower and drinking fountain, no additional space available	Wellness Room or Nursing Mother Room, shower and drinking fountain, with space available to add Wellness or NMR	Wellness Room and Nursing Mother room, shower and drinking fountain, with space available for Trainer	Wellness room, Trainer room, Nursing Mother Room, shower and drinking fountain nearby

Hastings Service Center – Alternatives Matrix

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Alternative Scenario Evaluation Matrix - Hastings Service Center Major Systems Upgrade

	Weight	Build on New Site Score	Build on Ex. Site Score	Renov. Existing Score	Do Nothing Score	COMMENTS
Section 1 - Affordable (50%)						
Operating cost per square foot below statewide average	40%	4.0	4.0	2.0	1.0	Current facility operating cost for Hastings is $13.85 per square foot, versus statewide average operating cost of $5.31 per square foot.
Construction cost	10%	2.0	2.0	3.0	4.0	
Section 1 - Scenario Average Weighted Score Total (Best = 5):		1.8	1.8	1.1	0.8	
Section 2 - Safe (12.5%)						
Hazardous Material Abatement (asbestos, lead paint)	2.5%	4.00	4.0	3.0	2.0	
Reduced site congestion and improved vehicular traffic flow	10%	4.00	3.00	1.00	1.00	
Section 2 - Scenario Average Score Total (Best = 5):		0.5	0.4	0.2	0.2	
Section 3 - Reliable (25%)						
Overall score above 72 as measured by Facilites Scorecard	5%	4.0	4.0	3.0	1.0	Current overall facility score for Hastings is 41
On Premise start times improved by 5 to 10 minutes	10%	4.0	4.0	2.0	1.0	Improved material flow and vehicle loading
Drive through vehicle repair bays	5%	4.0	4.0	3.0	3.0	Improved vehicle repair time, reduced vehicle damage
Temporary relocation of operations	5%	4.0	1.0	2.0	4.0	
Section 3 - Scenario Weighted Score Total (Best = 5):		1.0	0.9	0.6	0.5	
Section 4 - Clean (12.5%)						
LEED V4.1 Certification	2.5%	4.0	4.0	2.0	1.0	
Stormwater detention and treatment	2.5%	4.0	4.0	3.0	1.0	Stormwater currently discharged to ditch
Onsite solar power generation	2.5%	4.0	4.0	1.0	1.0	
Municipal Utilities Available	5%	1.0	4.0	4.0	4.0	Available parcels are located outside Hastings urban area, private well and septic will be required
Section 3 - Scenario Weighted Score Total (Best = 5):		0.4	0.5	0.4	0.3	
TOTAL WEIGHTED VALUE SCORE: (BEST = 5)	100%	3.7	3.6	2.2	1.7	

Hastings Service Center – Alternatives Matrix Criteria

Safe
Hazardous Material Abatement (asbestos, lead paint)
Reduced site congestion and improved vehicular traffic flow
Affordable
Operating cost per square foot below statewide average
Construction cost
Reliable
Overall score above 72 as measured by Facilites Scorecard
On Premise start times improved by 5 to 10 minutes
Temporary relocation of operations
Drive through vehicle repair bays
Clean
LEED V4.1 Certification
Stormwater detention and treatment
Onsite solar power generation
Municipal Utilities Available
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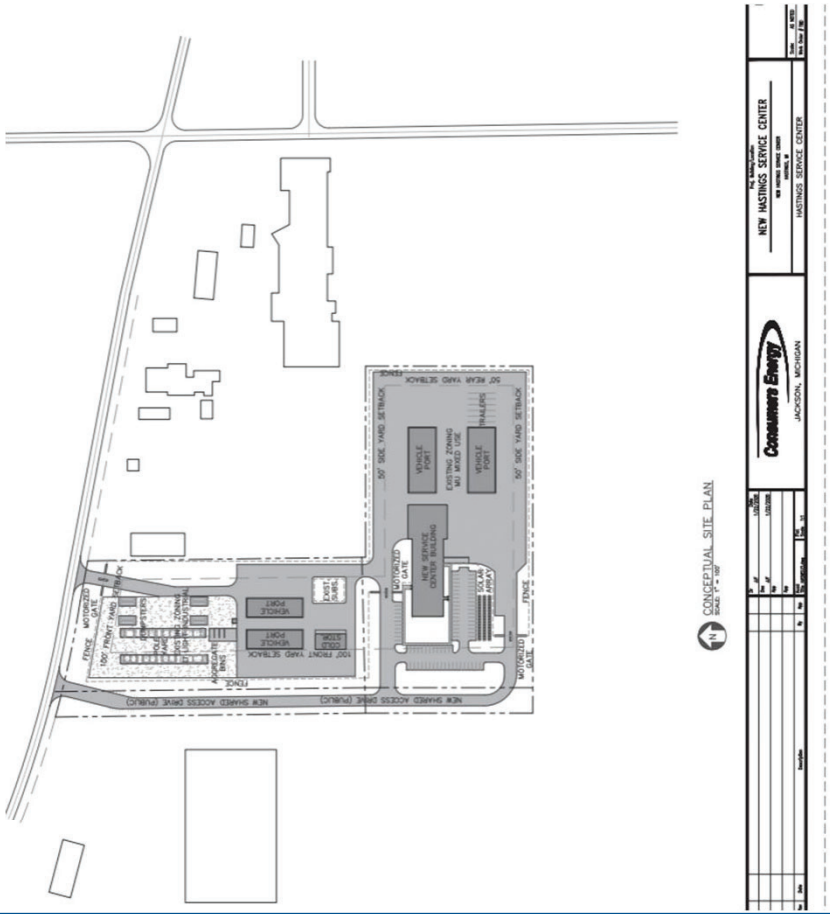
Hastings Service Center – Conceptual Site Plan



Gas Call Drive Time Summary

- **For the current Hastings Service Center and the proposed site at Vacant Land M-179**
  - Within 20 minutes we are able to reach 50% of gas customers and in 40 minutes we are able to reach 100% of gas customers.
- **For the proposed site at Vacant Land Enterprise Drive**
  - Within 25 minutes we are able to reach 50% of gas customers and in 45 minutes we are able to reach 100% of gas customers.

Electric Outage Drive Time Summary

- **For the current Hastings Service Center and the proposed site at Vacant Land M-179**
  - Within 15 minutes we are able to reach 50% of electric customers and in 30 minutes we are able to reach 100% of electric customers.
- **For the proposed site at Vacant Land Enterprise Drive**
  - Within 20 minutes we are able to reach 50% of electric customers and in 30 minutes we are able to reach 100% of electric customers.

Summary Site Comparison

Vacant Land: Enterprise Dr

- Public water and septic
- Would add 5 minutes to both electric and gas drive times

Vacant Land: M-179

- Private water and septic
- Drive times would remain similar to what is being experienced at the current location

Hastings Service Center Site Options Comparison

Vacant Land: Enterprise Dr, Hastings, MI 49058

Characteristics:

- Property – 18 acres
- Municipal Water – Available at the street
- Municipal Sewer – Available at the street
- Fiber – Available
- Wetlands – No mitigation required
- 3-Phase – Available at the street
- Natural Gas – Available at the street

Vacant Land: M-179, Hastings, MI 49058

Characteristics:

- Property – 30 Acres
- Private Water System – New system needed
- Private Septic System – New system needed
- Fiber – Available
- Wetlands – No mitigation required
- 3-Phase – Available at the street
- Natural Gas – Available at the street

Vacant Land: M-179, Hastings, MI 49058

Location Description: Just west of the corner of M-43 and M-37, on M-179 at M-43. Just East of Kellogg Community College parcel.

Access: Main entrance off M-37

Owner: 2 property owners have been approached one being Kellogg Community College

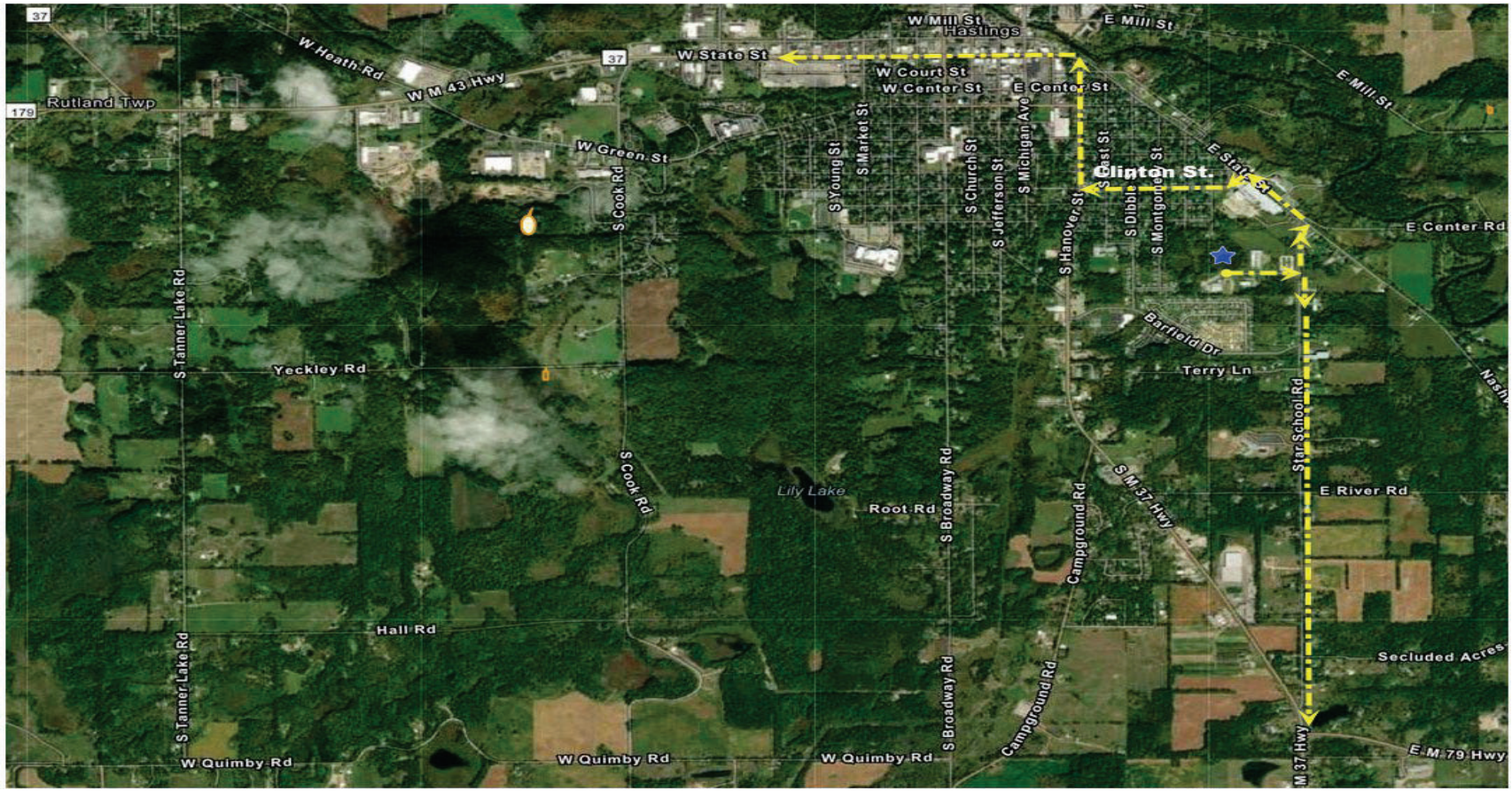
Vacant Land: Enterprise Dr, Hastings, MI 49058

Location Description: Southeast in the City just off E State St and Star School Rd in the Industrial Park

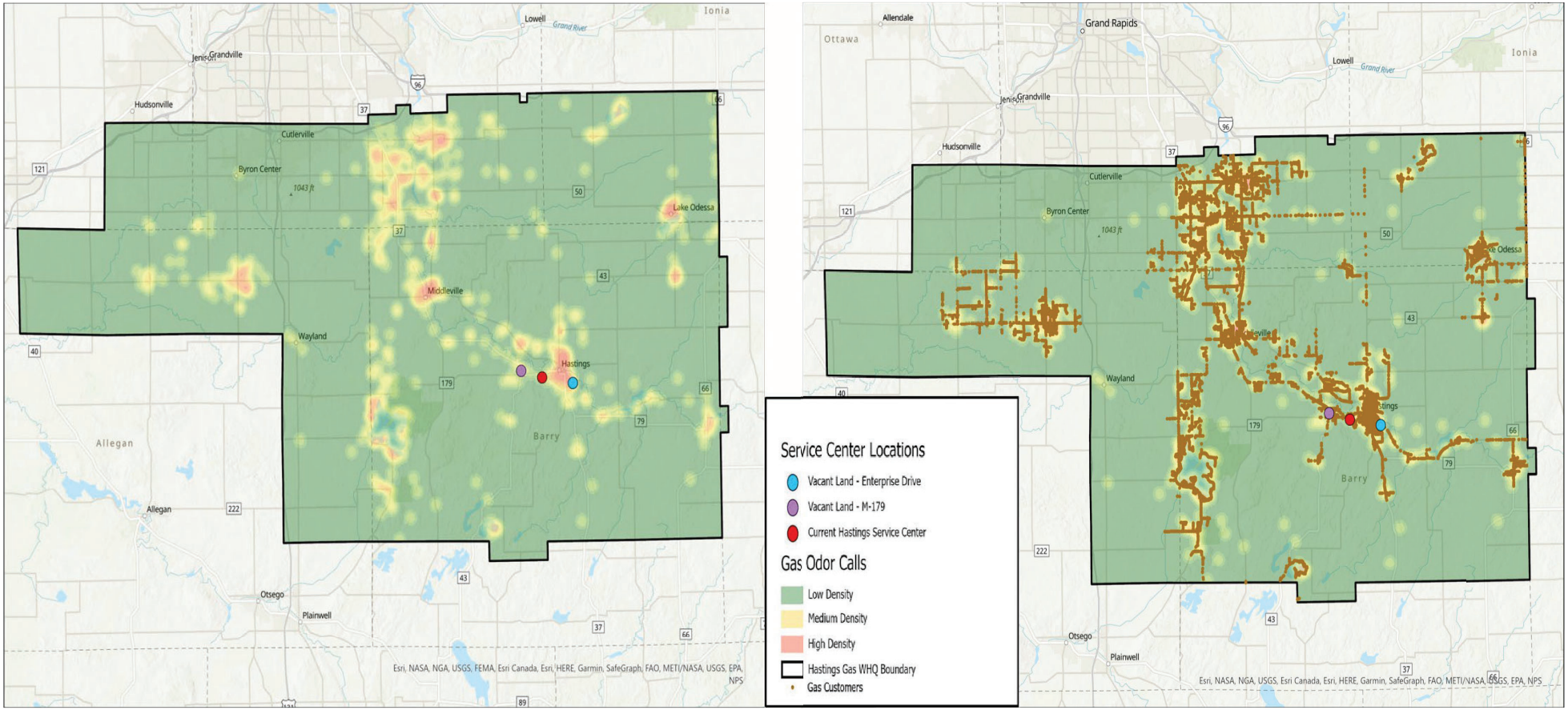
Access: There could be multiple drives on E. Enterprise Dr. Northeast parcel has access to Star School Rd.

Owner: City of Hastings, parcels are currently for sale.

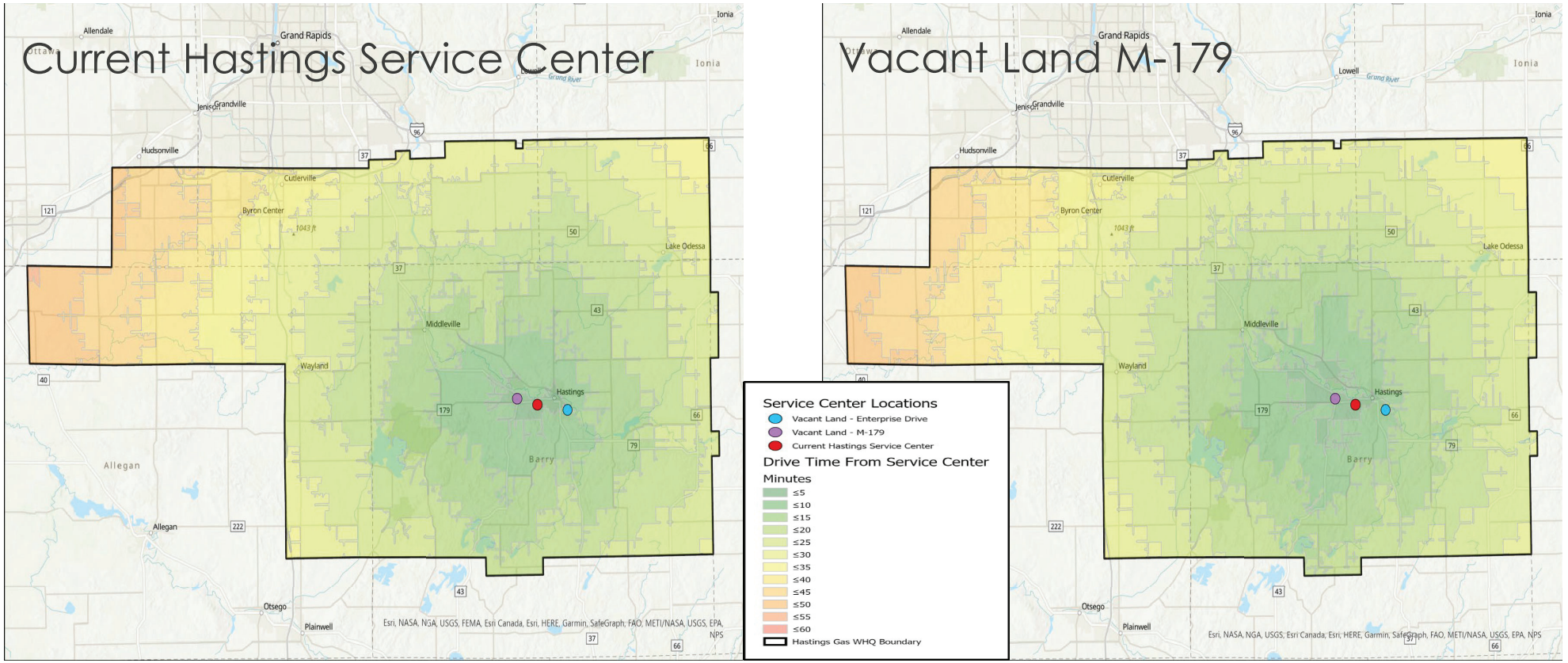
Class A Road Access Vacant Land Enterprise Dr.



2019-2020 Density of Gas Odor Calls and Customer Data

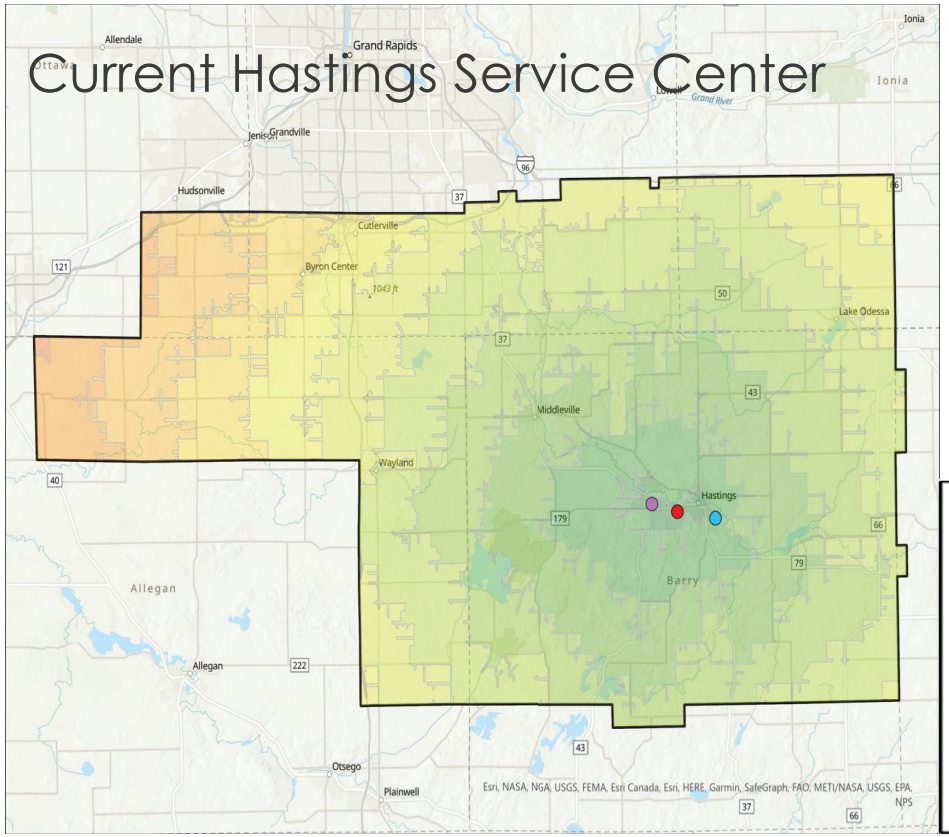


Gas Call Drive Times

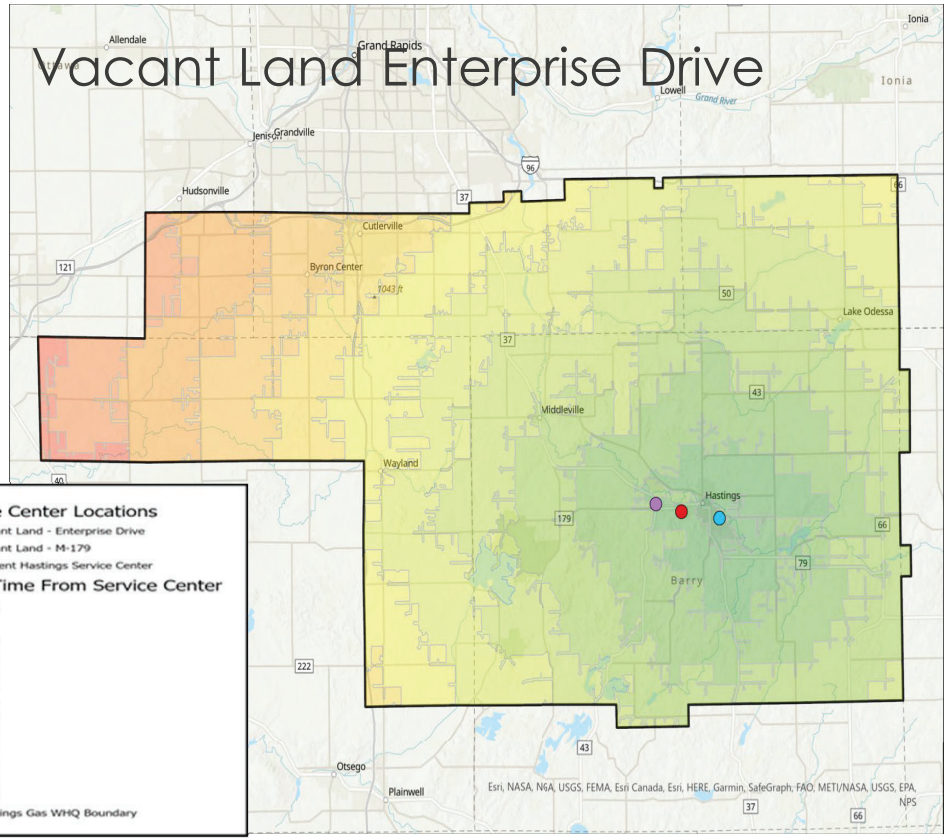


Gas Call Drive Times

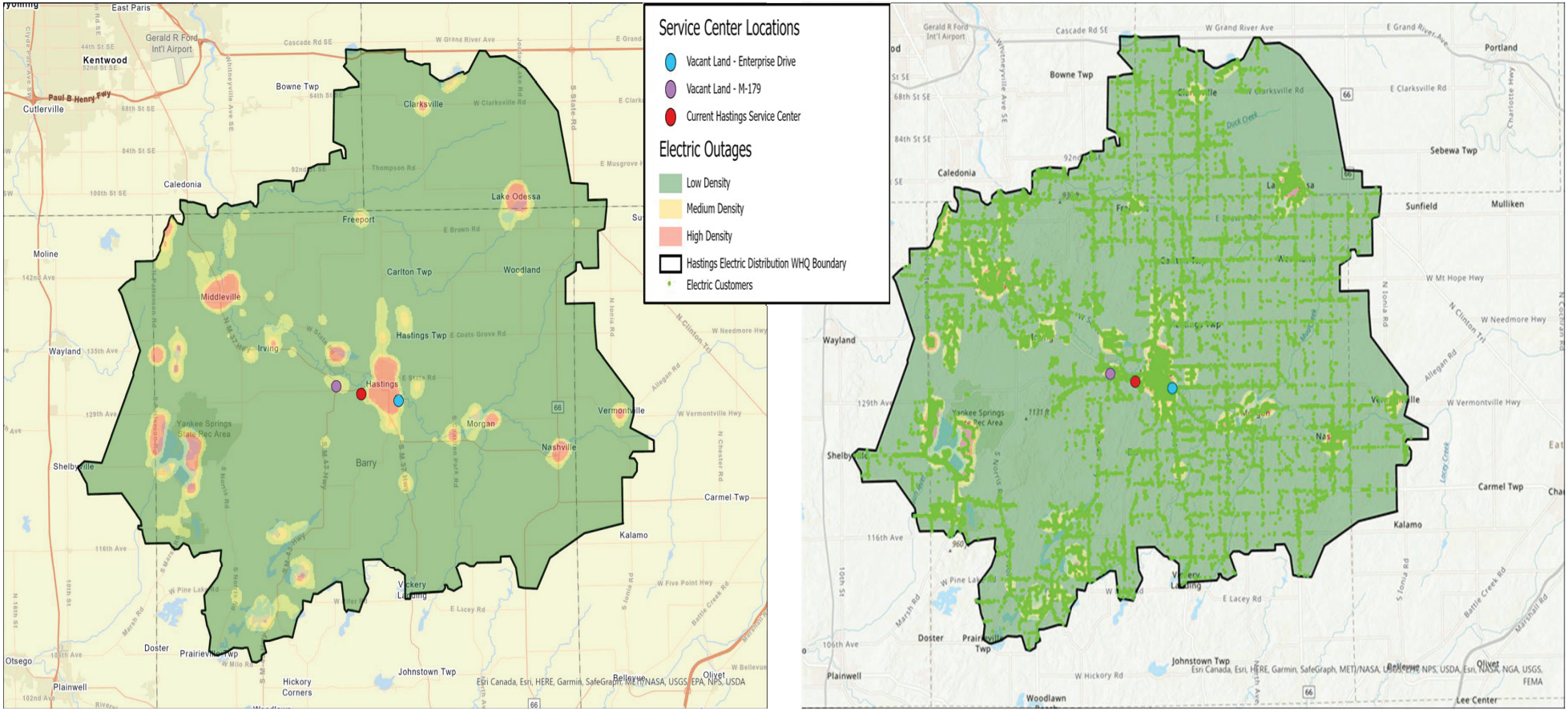
Current Hastings Service Center



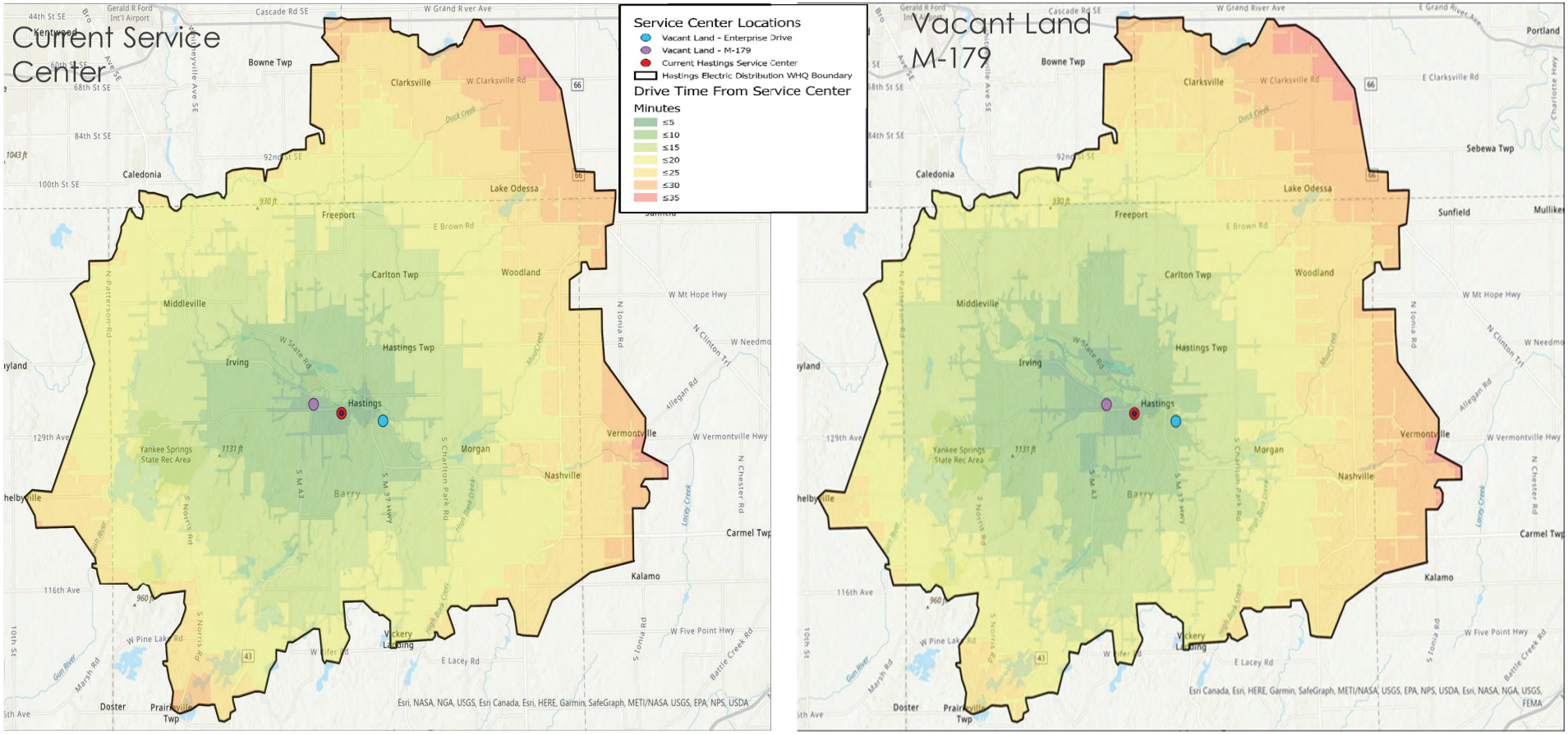
Vacant Land Enterprise Drive



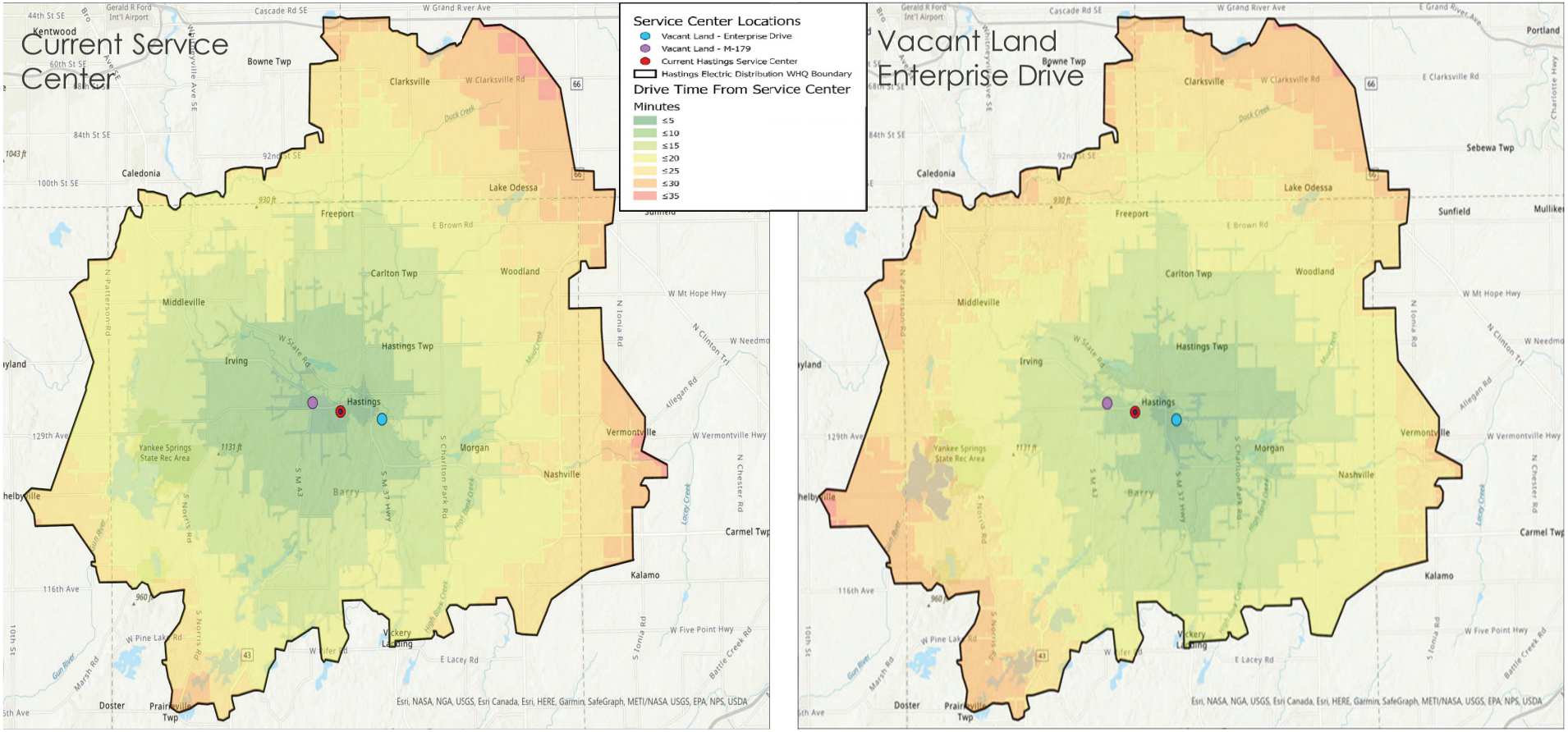
2019-2020 Density of Electric Outages and Customer Data



Electric Call Drive Times



Electric Call Drive Times



Kalamazoo Service Center

Plan Summary

Consumers Energy
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CMS ENERGY

Kalamazoo Service Center – Health Assessment

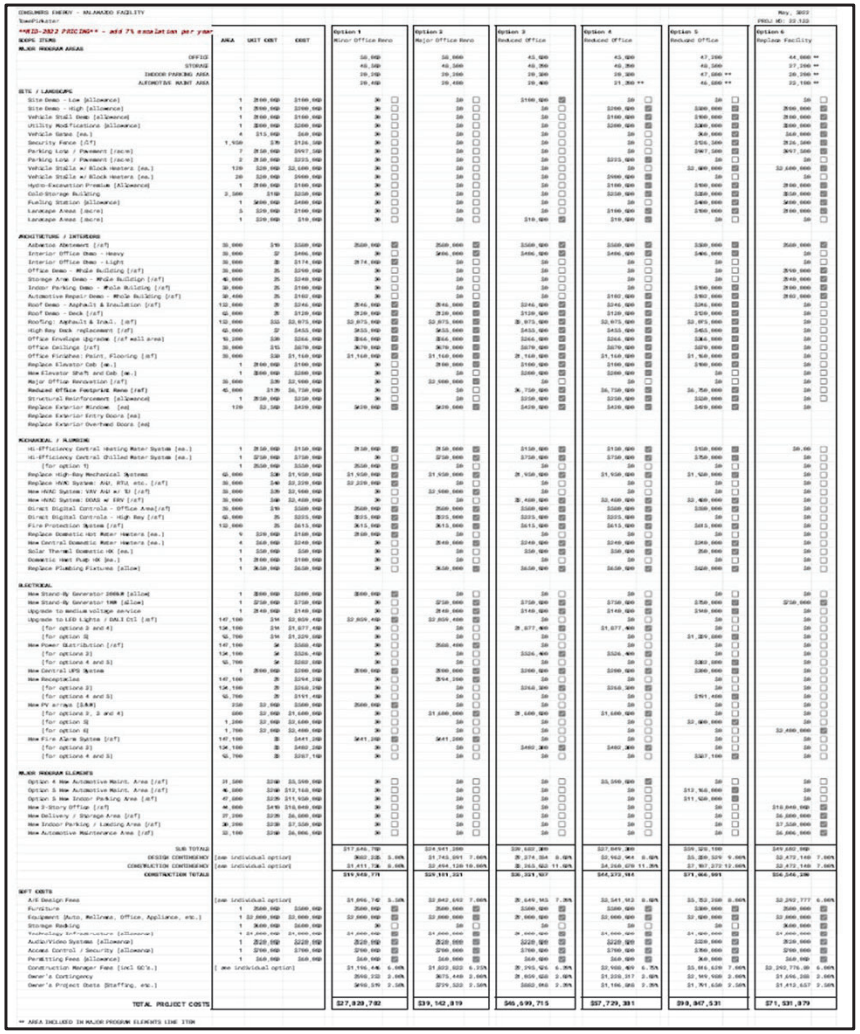
Facility Assessment - Kalamazoo Service Center						
Location	Kalamazoo		Maximum Possible Points (80)	Servicable > 48 Points	Poor < 48 Points	Good > 64 Points
Zone	SWOM					
Safety						
Compatible Use	4		5	3	2	4
Site Conditions	5		5	3	2	4
Traffic/Site Flow	3		5	3	2	4
Environmental Hazard	0		5	3	2	4
Quality						
Branding	3		5	3	2	4
Workplace Efficiency	3		5	3	2	4
Years since last major systems upgrade	0		5	3	2	4
Cost						
Facility Operating Costs	5		5	3	2	4
Non Facility Cost Impact	4		5	3	2	4
Space Optimization	1		5	3	2	4
Delivery						
Drive Time	3		5	3	2	4
Customer Response	4		5	3	2	4
Sustainability	1		5	3	2	4
Morale						
Employee Pride	1		5	3	2	4
Retention	4		5	3	2	4
Wellness	5		5	3	2	4
Total	***46***		***80***	***48***	***32***	***64***

Kalamazoo Service Center
Health Assessment Scoring Criteria

Safety (20 Points)	**Score 0** Does not satisfy criteria	**Score 1** Does not satisfy most listed criteria	**Score 2** Does not satisfy some listed criteria	**Score 3** Satisfies minimal criteria	**Score 4** Satisfies most listed criteria	**Score 5** Satisfies all listed criteria
Compatible Use	Residential zoning, high crime area	Residential zoning	Mixed Commercial / Residential zoning	Commercial zoning for Service Centers, mixed Commercial / Industrial zoning for non-Service Centers	Mixed Commercial / Industrial zoning for Service Centers, Commercial zoning for non-Service Centers	Industrial zoning for Service Centers, Central Business District zoning for non-Service Centers
Site Conditions	Site not adequate to support operational requirements, located in flood plain,	Site not adequate to support operational requirements	significant upgrades, such as storm water detention, fire water, potable water, sanitary sewer, paving, etc.	Site in serviceable condition with full utilities or good condition with partial utilities	Site in good condition, full utilities	Site in good condition with undeveloped space to accommodate future growth
Traffic/Site Flow	Unimproved road frontage / site traffic flows crossing	Non Class A road frontage / Site heavy traffic and light traffic flows crossing	with impediments, railroad tracks, intersections, etc. / Site traffic flows crossing	Class A road frontage / Site traffic flows mixed	Class A road frontage with secondary frontage / Site traffic flows separated	Class A road frontage with secondary frontage and nearby highway access / Site traffic flows separated
Environmental Hazard	Immediate hazards to employees present during normal use of site	Hazardous materials present, with reoccurring or continuous exposure hazard, former MGP site, current 201 site	Hazardous materials present in manageable form, former MGP site, current 201 site	Hazardous materials present in manageable form	No environmental impacts, hazardous materials abated or encapsulated	LEED Certified facility with no environmental impacts
Quality (15 Points)	**Score 0**	**Score 1**	**Score 2**	**Score 3**	**Score 4**	**Score 5**
Branding	damaged or deteriorated structures, landscape materials overgrown or absent, failed pavement, etc.	Structures deteriorated, landscape materials overgrown or absent, failing paving, no signage	Structures poorly maintained, landscape materials overgrown or absent, poor signage	Structures well cared for, landscape materials in serviceable condition, uncoordinated signage	Structures well cared for, landscape materials in good condition, coordinated signage	New facility, landscape materials in good condition, coordinated signage
Workplace Efficiency	Space inadequate for intended occupancy	Hard wall offices, empty or vacant spaces	Hard wall offices, fully utilized	Mix of hard wall offices and systems furniture, fully utilized	Modular systems furniture, fully utilized	Flexible, open and collaborative workspaces, modular systems furniture, fully utilized
Years since last major systems upg	construction or last major systems upgrade	initial construction or last major systems uprade	initial construction or last major systems uprade	initial construction or last major systems uprade	initial construction or last major systems uprade	0-10 years since initial construction or last major systems uprade
Cost (15 Points)	**Score 0**	**Score 1**	**Score 2**	**Score 3**	**Score 4**	**Score 5**
Facility Operating Costs	costs greater than $10.00 per square foot	costs between $8.00 to $10.00 per square foot	costs between $7.25 to $7.99 per square foot	costs between $7.00 to $7.24 per square foot	costs between $5.75 to $6.99 per square foot	Combined operating costs less than $5.75 per square foot
Non Facility Cost Impact	Building eccentrically located within service territory, inadequate space	Building eccentrically located within service territory, underutilized space	Building eccentrically located within service territory	Building centrally located within service territory	Building accommodates operational needs, centrally located within service territory	Building accommodates operational need, space utilized efficiently, centrally located within service territory
Space Optimization	Building vacant	Building partially occupied or partially vacant	Building occupied inefficiently, includes IPA	Building fully occupied, includes IPA	Building fully occupied, no IPA	Building fully occupied, no IPA, includes cold storage

Delivery (15 Points)						
Drive Time	service territory and size of service territory allows drive time >1:20 Gas and >1:30 Electric	service territory and size of service territory allows drive time < 1:20 Gas and <1:30 Electric	Location within service territory and size of service territory allows drive time < 1:10 Gas and <1:15 Electric	service territory and size of service territory allows drive time < 1:00 Gas and <1:00 Electric	service territory and size of service territory allows drive time < 0:50 Gas and <0:45 Electric	service territory and size of service territory allows drive time < 0:40 Gas and <0:30 Electric
Customer Response	response times meet target <90% of time, Electric CAIDI >215 minutes	response times meet target >90% of time, Electric CAIDI <215 minutes	response times meet target >95% of time, Electric CAIDI <195 minutes	response times meet target >97% of time, Electric CAIDI <180 minutes	response times meet target >98% of time, Electric CAIDI <165 minutes	response times meet target >99% of time, Electric CAIDI <150 minutes
Sustainability	Minimal roofing insulation	Upgraded roofing insulation	Upgraded roofing insulation and windows	Upgraded roofing insulation, windows and building envelope	Upgraded roofing insulation, windows, and building envelope with onsite storm water treatment	LEED Certified (or higher LEED rated) facility
Morale (15 Points)	**Score 0**	**Score 1**	**Score 2**	**Score 3**	**Score 4**	**Score 5**
Employee Pride	Deteriorated facility	Deteriorated or dated facility with limited amenities	Dated facility with minimal amenities	Dated facility with full amenities and onsite parking	Modern facility with full amenities	Modern facility with full amenities, onsite parking
Retention	Remote location, no local amenities	some amenities available within 20 minutes driving distance	Remote location, amenities available within 20 minutes driving distance	Remote location, amenities available within 15 minutes driving distance	Diverse location, amenities available within 10 minutes driving distance	Diverse location, amenities available within walking distance
Wellness	No shower, drinking fountain, Wellness or Nursing Mother Room, no additional space available	Shower and drinking fountain, no Wellness or Nursing Mother Room, no additional space available	Wellness Room or Nursing Mother Room, shower and drinking fountain, no additional space available	Wellness Room or Nursing Mother Room, shower and drinking fountain, with space available to add Wellness or NMR	Wellness Room and Nursing Mother room, shower and drinking fountain, with space available for Trainer	Wellness room, Trainer room, Nursing Mother Room, shower and drinking fountain nearby

Kalamazoo Service Center: Alternatives Summary



CONSUMERS ENERGY - KALAMAZOO FACILITY
Date: May, 2023
Taxe/Master: PROJ NO: 22-122

MID-2022 PRICING - add 7% escalation per year

SCOPE ITEMS	AREA	UNIT COST	COST	Option 1 Minor Office Reno	Option 2 Major Office Reno	Option 3 Reduced Office	Option 4 Reduced Office	Option 5 Reduced Office	Option 6 Replace Facility
MAJOR PROGRAM AREAS									
OFFICE				32,000	32,000	41,500	41,500	47,000	44,000 **
STORAGE				40,100	40,100	40,350	40,350	46,100	37,100 **
INDOOR PARKING AREA				39,300	39,300	39,300	39,300	47,000 **	39,300 **
AUTOMOTIVE MAINT AREA				39,400	39,400	39,400	21,350 **	46,000 **	39,100 **
SITE / LANDSCAPE									
Site Demo - Low [allowance]	1	$160,000	$160,000	X	No	$160,000	No	No	No
Site Demo - High [allowance]	1	$300,000	$300,000	X	No	No	$300,000	$300,000	$300,000
Vehicle Stall Demo [allowance]	1	$160,000	$160,000	X	No	No	$160,000	$160,000	$160,000
Utility Modifications [allowance]	1	$300,000	$300,000	X	No	No	$300,000	$300,000	$300,000
Vehicle Gates [ea.]	4	$10,000	$40,000	X	No	No	No	$40,000	$40,000
Security Fence [LF]	1,450	$75	$126,000	X	No	No	No	$126,500	$126,500
Parking Lots / Pavement [recm]	7	$130,000	$917,000	X	No	No	No	$917,000	$917,000
Parking Lots / Pavement [recm]	2	$130,000	$223,000	X	No	No	$223,000	No	No
Vehicle Stalls w/ Block Heaters [ea.]	120	$20,000	$2,400,000	X	No	No	No	$2,400,000	$2,400,000
Vehicle Stalls w/ Block Heaters [ea.]	20	$30,000	$600,000	X	No	No	$600,000	No	No
Hydro-Excavation Premium [Allowance]	1	$160,000	$160,000	X	No	No	$160,000	$160,000	$160,000
Cold Storage Building	2,500	$150	$330,000	X	No	No	$330,000	$330,000	$330,000
Fueling Station [allowance]	1	$400,000	$400,000	X	No	No	No	$400,000	$400,000
Landscape Areas [acre]	5	$20,000	$100,000	X	No	No	$100,000	$100,000	$100,000
Landscape Areas [acre]	1	$20,000	$10,000	X	No	$10,000	No	No	No
ARCHITECTURE / INTERIORS									
Asbestos Abatement [sf]	30,000	$10	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000
Interior Office Demo - Heavy	30,000	$7	$200,000	X	$200,000	$200,000	$200,000	$200,000	No
Interior Office Demo - Light	30,000	$5	$174,000	$174,000	No	No	No	No	No
Office Demo - Whole Building [sf]	30,000	$5	$150,000	X	No	No	No	No	$150,000
Storage Area Demo - Whole Building [sf]	40,000	$5	$240,000	X	No	No	No	No	$240,000
Indoor Parking Demo - Whole Building [sf]	30,000	$5	$150,000	X	No	No	No	$300,000	$300,000
Automotive Repair Demo - Whole Building [sf]	30,400	$5	$160,000	X	No	No	$152,000	$302,000	$302,000
Roof Demo - Asphalt & Insulation [sf]	132,000	$3	$241,000	$241,000	$241,000	$241,000	$241,000	$241,000	No
Roof Demo - Deck [sf]	12,000	$5	$120,000	$120,000	$120,000	$120,000	$120,000	$120,000	No
Roofing: Asphalt & Insul. [sf]	132,000	$22	$2,973,000	$2,973,000	$2,973,000	$2,973,000	$2,973,000	$2,973,000	No
High Bay Deck replacement [sf]	12,000	$7	$433,000	$433,000	$433,000	$433,000	$433,000	$433,000	No
Office Envelope Upgrades [sf wall area]	10,100	$30	$264,000	$264,000	$264,000	$264,000	$264,000	$264,000	No
Office Ceilings [sf]	30,000	$10	$270,000	$270,000	$270,000	$270,000	$270,000	$270,000	No
Office Finishes: Paint, Flooring [sf]	30,000	$30	$1,140,000	$1,140,000	$1,140,000	$1,140,000	$1,140,000	$1,140,000	No
Replace Elevator Cab [ea.]	1	$160,000	$160,000	X	$160,000	$160,000	$160,000	$160,000	No
New Elevator Shaft and Cab [ea.]	1	$260,000	$260,000	No	No	$260,000	$260,000	No	No
Major Office Renovation [sf]	30,000	$30	$2,000,000	X	$2,000,000	No	No	No	No
Reduced Office Footprint Reno [sf]	6,000	$15	$6,730,000	X	No	X, 730,000	$6,730,000	$6,730,000	No
Structural Reinforcement [allowance]	1	$250,000	$250,000	X	$250,000	$250,000	$250,000	$250,000	No
Replace Exterior Windows [ea]	120	$2,500	$420,000	$420,000	$420,000	$420,000	$420,000	$420,000	No
Replace Exterior Entry Doors [ea]									
Replace Exterior Overhead Doors [ea]									
MECHANICAL / PLUMBING									
HI-Efficiency Central Heating Water System [ea.]	1	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$150,000	$0.00
HI-Efficiency Central Chilled Water System [ea.]	1	$730,000	$730,000	X	$730,000	$730,000	$730,000	$730,000	No
[for option 1]	1	$550,000	$550,000	$550,000	No	No	No	No	No
Replace High Bay Mechanical Systems	12,000	$30	$1,930,000	$1,930,000	$1,930,000	$1,930,000	$1,930,000	$1,930,000	No
Replace HVAC Systems: AHU, RTU, etc. [sf]	30,000	$40	$2,220,000	$2,220,000	No	No	No	No	No
New HVAC System: VAV AHU w/ DX [sf]	30,000	$35	$2,660,000	X	$2,660,000	No	No	No	No
New HVAC System: DOAS w/ VRV [sf]	30,000	$40	$2,400,000	No	No	$2,400,000	$2,400,000	$2,400,000	No
Direct Digital Controls - Office Area [sf]	30,000	$10	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000	No
Direct Digital Controls - High Bay [sf]	12,000	$5	$203,000	$203,000	$203,000	$203,000	$203,000	No	No
Fire Protection System [sf]	132,000	$5	$613,000	$613,000	$613,000	$613,000	$613,000	$613,000	No
Replace Domestic Hot Water Heaters [ea.]	4	$20,000	$160,000	$160,000	No	No	No	No	No
New Central Domestic Water Heaters [ea.]	4	$60,000	$240,000	No	$240,000	No	$240,000	$240,000	No
Solar Thermal Domestic HW [ea.]	1	$30,000	$30,000	X	No	$30,000	$30,000	$30,000	No
Domestic Heat Pump HW [ea.]	1	$100,000	$100,000	X	No	No	No	No	No
Replace Plumbing Fixtures [allow]	1	$630,000	$630,000	X	$630,000	$630,000	$630,000	$630,000	No
ELECTRICAL									
New Stand-By Generator 200kW [allow]	1	$200,000	$200,000	$200,000	No	No	No	No	No
New Stand-By Generator 1MW [allow]	1	$730,000	$730,000	X	$730,000	$730,000	$730,000	$730,000	$730,000
Upgrade to Medium voltage service	1	$149,000	$149,000	X	$149,000	$149,000	$149,000	$149,000	No
Upgrade to LED Lights / DALI Ctl [sf]	147,100	$14	$2,059,400	$2,059,400	$2,059,400	No	No	No	No
[for options 2 and 4]	134,100	$14	$1,877,400	X	No	$1,877,400	$1,877,400	No	No
[for option 5]	46,700	$14	$1,229,000	X	No	No	No	$1,229,000	No
New Power Distribution [sf]	147,100	$4	$588,400	X	$588,400	No	No	No	No
[for options 2]	134,100	$4	$536,400	X	No	$536,400	$536,400	No	No
[for options 4 and 5]	46,700	$4	$282,000	X	No	No	No	$282,000	No
New Central UPS System	1	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000	$300,000	No
New Receptacles	147,100	$5	$294,200	X	$294,200	No	No	No	No
[for options 2]	134,100	$5	$268,200	X	No	$268,200	$268,200	No	No
[for options 4 and 5]	46,700	$5	$191,400	X	No	No	No	$191,400	No
New PV arrays [EAR]	250	$2,000	$500,000	$500,000	No	No	No	No	No
[for options 3, 3 and 4]	500	$2,000	$1,000,000	X	$1,000,000	$1,000,000	$1,000,000	No	No
[for option 5]	1,200	$2,000	$2,400,000	X	No	No	No	$2,400,000	No
[for option 6]	1,700	$2,000	$2,400,000	X	No	No	No	No	$2,400,000
New Fire Alarm System [sf]	147,100	$3	$441,300	$441,300	No	No	No	No	No
[for options 2]	134,100	$3	$402,300	X	No	$402,300	$402,300	No	No
[for options 4 and 5]	46,700	$3	$267,100	X	No	No	No	$267,100	No
MAJOR PROGRAM ELEMENTS									
Option 4 New Automotive Maint. Area [sf]	21,000	$250	$5,000,000	X	No	No	$5,000,000	No	No
Option 5 New Automotive Maint. Area [sf]	46,000	$250	$12,140,000	X	No	No	No	$12,140,000	No
Option 5 New Indoor Parking Area [sf]	47,000	$235	$11,030,000	X	No	No	No	$11,120,000	No
New 2-Story Office [sf]	46,000	$470	$19,040,000	X	No	No	No	No	$19,040,000
New Delivery / Storage Area [sf]	27,100	$235	$6,000,000	X	No	No	No	No	$6,000,000
New Indoor Parking / Loading Area [sf]	30,000	$235	$7,100,000	X	No	No	No	No	$7,100,000
New Automotive Maintenance Area [sf]	21,100	$250	$5,000,000	X	No	No	No	No	$5,000,000
SUB TOTALS				$27,000,700	$24,941,200	$26,602,300	$27,049,300	$26,120,100	$49,102,000
DESIGN CONTINGENCY	[see individual option]			$602,235 5.00%	$1,743,991 7.00%	$1,874,304 6.00%	$2,162,944 8.00%	$3,258,329 9.00%	$2,472,148 7.00%
CONSTRUCTION CONTINGENCY	[see individual option]			$1,613,736 6.00%	$2,494,120 10.00%	$2,263,622 11.00%	$4,318,678 11.35%	$7,367,272 12.00%	$2,472,148 7.00%
CONSTRUCTION TOTALS				$29,216,771	$29,179,311	$30,740,227	$33,530,922	$36,745,701	$53,046,296
SOFT COSTS									
A/E Design Fees	[see individual option]			$1,606,742 5.50%	$2,042,692 7.00%	$2,049,163 7.00%	$2,511,903 8.00%	$2,752,288 8.00%	$2,262,777 6.00%
Furniture	1	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000
Equipment [Auto, Wellness, Office, Appliance, etc.]	1	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
Storage Racking	1	$600,000	$600,000	No	No	No	No	No	$600,000
Technology Infrastructure [allowance]	1	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000
Audio/Video Systems [allowance]	1	$529,000	$529,000	$529,000	$529,000	$529,000	$529,000	$529,000	$529,000
Access Control / Security [allowance]	1	$700,000	$700,000	$700,000	$700,000	$700,000	$700,000	$700,000	$700,000
Permitting Fees [allowance]	1	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000	$60,000
Construction Manager Fees [incl GC's.]	[see individual option]			$1,156,446 4.00%	$1,602,622 5.15%	$1,761,524 5.73%	$2,008,809 6.00%	$3,161,620 7.00%	$2,262,776.88 6.00%
Owner's Contingency				$560,312 2.00%	$873,440 3.00%	$1,020,622 3.32%	$1,339,317 3.99%	$2,193,108 5.00%	$1,696,332 4.50%
Owner's Project Costs [Staffing, etc.]				$490,273 1.75%	$729,533 2.50%	$882,043 2.87%	$1,116,265 3.33%	$1,761,658 4.00%	$1,412,637 3.75%
TOTAL PROJECT COSTS				$27,839,782	$33,142,819	$36,699,715	$37,729,331	$39,847,531	$71,931,979

** AREA INCLUDED IN MAJOR PROGRAM ELEMENTS LINE ITEM

Kalamazoo Service Center: Renovation Expected Energy Usage Reductions (Alternative #1)

CONSUMERS KALAMAZOO SERVICE CENTER

2500 EAST CORK STREET

BUILDING AREAS BY TYPE

	ALT 1	ALT 2	ALT 3	ALT 4	ALT 5	ALT 6
OFFICE	58,000	58,000	45,000	45,000	47,200	44,000
STORAGE	48,500	48,500	48,500	48,500	48,500	27,200
INDOOR PARKING	20,200	20,200	20,200	20,200	47,800	30,200
AUTO MAINTENANCE	20,400	20,400	20,400	21,500	46,800	23,100
TOTAL	147,100	147,100	134,100	135,200	190,300	124,500

ESTIMATED ENERGY USE - CONCEPT LEVEL

	ALT 1	ALT 2	ALT 3	ALT 4	ALT 5	ALT 6
Total Area (SF)	147,100	147,100	134,100	135,200	190,300	124,500
Baseline EUI, CBECS Weighted (kBtu/SF)	42	42	41	41	43	44
Estimated Overall Reduction	10%	20%	25%	30%	35%	45%
Reduced EUI (kBtu/SF)	38	33	30	28	28	24
Estimated Annual Energy Use (kBtu)	5,524,470	4,910,640	4,086,975	3,851,470	5,302,635	3,033,800

Kalamazoo Service Center – Electric Customer Drive Times

Kalamazoo Service Center – Electric Customer Drive Times

Eastern Electric

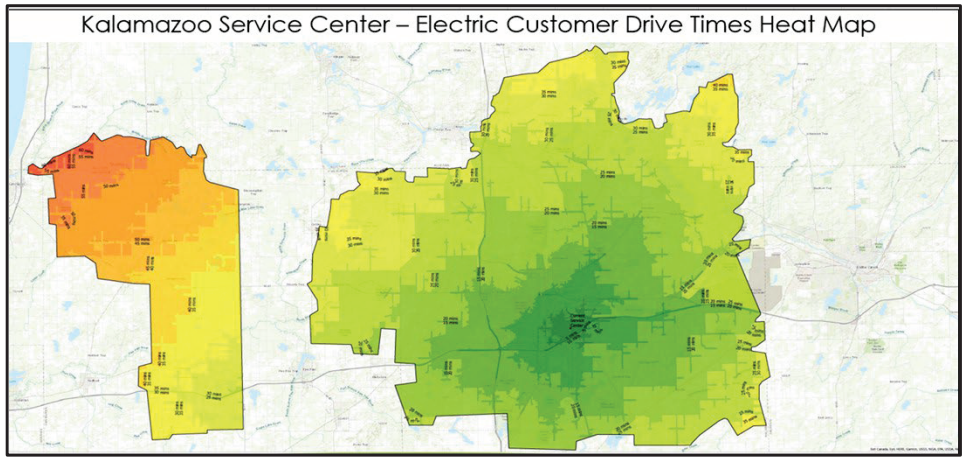
Drive Time (minutes)	Count of Customers	Percentage	Cumulative Percentage
5	1,450	1.1%	1.1%
10	20,759	16.0%	17.1%
15	46,583	35.9%	53.1%
20	40,146	31.0%	84.0%
25	8,651	6.7%	90.7%
30	6,174	4.8%	95.5%
35	1,953	1.5%	97.0%
40	**934**	0.7%	97.7%
45	646	0.5%	98.2%
50	1,493	1.2%	99.4%
55	605	0.5%	99.8%
60	229	0.2%	100.0%
Grand Total	**129,623**	**100%**	

Western Electric

Drive Time (minute	Count of Customers	Percentage	Cumulative Percentage
5	4,202	3.2%	3.2%
10	33,706	26.0%	29.2%
15	39,159	30.2%	59.5%
20	28,523	22.0%	81.5%
25	13,224	10.2%	91.7%
30	5,375	4.1%	95.8%
35	2,721	2.1%	97.9%
40	**1,906**	1.5%	99.4%
45	606	0.5%	99.8%
50	201	0.2%	100.0%
Grand Total	**129,623**	**100.00%**	

Northern Electric

Drive Time (minutes)	Count of Customers	Percentage	Cumulative Percentage
5	2,597	2.0%	2.0%
10	18,922	14.6%	16.6%
15	35,461	27.4%	44.0%
20	44,914	34.6%	78.6%
25	15,626	12.1%	90.7%
30	5,527	4.3%	94.9%
35	4,444	3.4%	98.4%
40	**1,688**	1.3%	99.7%
45	441	0.3%	100.0%
50	3	0.0%	
Grand Total	**129,623**	**100%**	



Kalamazoo Service Center – Gas Customer Drive Times

Kalamazoo Service Center – Gas Customer Drive Times

Current Gas

Drive Time (minutes)	Count of Customers		
5	5,113	5.1%	5.1%
10	21,900	21.7%	26.8%
15	36,026	35.7%	62.5%
20	19,219	19.1%	81.5%
25	7,601	7.5%	89.1%
30	3,731	3.7%	92.8%
35	4,713	4.7%	97.4%
40	1,608	1.6%	99.0%
45	749	0.7%	99.8%
50	162	0.2%	99.9%
55	59	0.1%	100.0%
Grand Total	100,881	100%	

Northern Gas

Drive Time (minutes	Count of Customers		
5	2,379	2.4%	2.4%
10	10,292	10.2%	12.6%
15	20,680	20.5%	33.1%
20	33,090	32.8%	65.9%
25	15,911	15.8%	81.6%
30	9,315	9.2%	90.9%
35	3,191	3.2%	94.0%
40	3,866	3.8%	97.9%
45	666	0.7%	98.5%
50	710	0.7%	99.2%
55	306	0.3%	99.5%
60	374	0.4%	99.9%
65	101	0.1%	100.0%
Grand Total	100,881	100%	

Western Gas

Drive Time (minutes	Count of Customers		
5	2,857	2.8%	2.8%
10	23,143	22.9%	25.8%
15	30,990	30.7%	56.5%
20	23,967	23.8%	80.2%
25	9,378	9.3%	89.5%
30	5,814	5.8%	95.3%
35	2,483	2.5%	97.8%
40	1,096	1.1%	98.9%
45	582	0.6%	99.4%
50	341	0.3%	99.8%
55	230	0.2%	100.0%
Grand Total	100,881	100%	

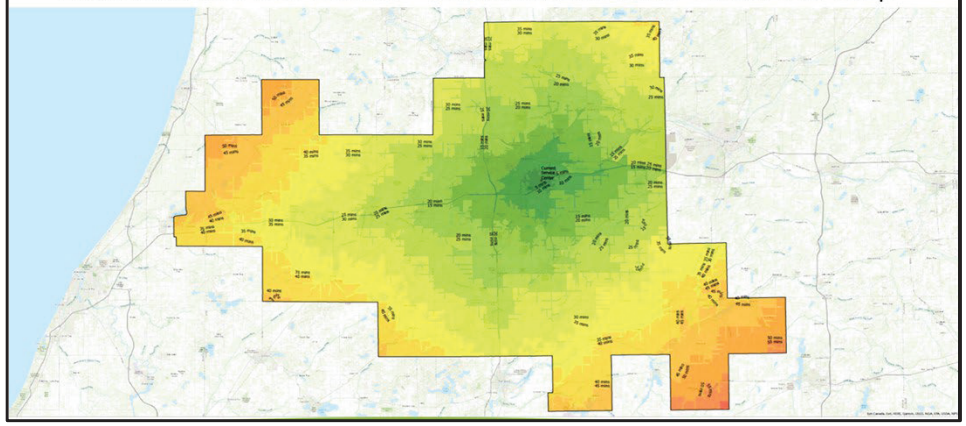
Eastern Gas

Drive Time (minutes)	Count of Customers		
5	1,285	1.3%	1.3%
10	16,770	16.6%	17.9%
15	32,817	32.5%	50.4%
20	29,244	29.0%	79.4%
25	7,816	7.7%	87.2%
30	6,199	6.1%	93.3%
35	2,469	2.4%	95.8%
40	3,025	3.0%	98.8%
45	1,197	1.2%	99.9%
50	59	0.1%	100.0%
Grand Total	100,881	100%	

Southern Gas

Drive Time (minutes	Count of Customers		
5	5,349	5.3%	5.3%
10	20,447	20.3%	25.6%
15	30,252	30.0%	55.6%
20	23,832	23.6%	79.2%
25	9,218	9.1%	88.3%
30	5,877	5.8%	94.1%
35	3,262	3.2%	97.4%
40	1,943	1.9%	99.3%
45	311	0.3%	99.6%
50	341	0.3%	100.0%
55	49	0.0%	100.0%
Grand Total	100,881		

Kalamazoo Service Center – Gas Customer Drive Times Heat Map



1. Tariff Sheet Nos. A-6.00, G-1.00 through G-3.00, G-5.00, G-6.00 and G-8.00 through G-11.00 – **Group Transportation Service Program** - revised Group Transportation Service Pilot Program name to Group Transportation Service Program.

2. Tariff Sheet No. C-37.00 - Rule C8.B – **Customer Attachment Program** – added waiver for winter construction charges at the Company's discretion.

3. Tariff Sheet No. C-40.00 – Rule C8.I (1) and (6) – **Customer Attachment Program** – Revised the carrying cost and discount rate.

4. Tariff Sheet Nos. D-2.00, D-2.10, D-2.30, D-9.00 and D-14.00 – **General Service Outdoor Lighting Rate GL** – revised tariff sheets to reflect proposed termination of General Service Outdoor Lighting Rate GL.

5. Tariff Sheet No. D-2.30, D-10.00 through D-13.00, E-8.00 and E-10.00 – **Revised prices**.

6. Tariff Sheet Nos. D-9.00 and E-13.00 through E-14.00 – **Transmission Only Gas Transportation Rate** – revised the Transmission Only Transportation Service Rate to include four rate options of STT, LTT, XLTT and XXLTT with both a Customer Charge and a Transportation Charge.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

12 Months Ending October 31, 2026 Gas Compression and Renewable Natural Gas O&M Expenses

($000)

Case No.: U-21806
Exhibit No.: A-72 (TKJ-1)
Page: 1 of 4
Witness: TKJoyce
Date: December 2024

Line No.	(a) Description	(b) Actual 12-Mos Ended 12/31/2023	(c) Projected 12-Mos Ending 10/31/2026
1	**Gas Compression**	18,695	17,577
2	**Compression Rebuilds**	(815)	-
3	**Renewable Natural Gas**	-	-
4	**TOTAL O&M**	**$ 17,880**	**$ 17,577**

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

12 Months Ending October 31, 2026 Gas Compression and Renewable Natural Gas O&M Expenses

($000)

Case No.: U-21806
Exhibit No.: A-72 (TKJ-1)
Page: 2 of 4
Witness: TKJoyce
Date: December 2024

Projected O&M Expenses

	(a)	(b)	(c)	(d)	(e)
			Projected		
Line No.	**Description**	**12 mos. Ended 12/31/2023**	**12 mos. Ending 12/31/2024**	**12 mos. Ending 12/31/2025**	**12 mos. Ending 10/31/2026**
1	**Gas Compression**	18,695	17,030	16,590	17,577
2	**Compression Rebuilds**	(815)	-	-	-
4	**Renewable Natural Gas**	-	-	-	-
5	**TOTAL O&M**	**$ 17,880**	**$ 17,030**	**$ 16,590**	**$ 17,577**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
12 Months Ending October 31, 2026 Gas Compression
and Renewable Natural Gas O&M Expenses
($000)

Case No.: U-21806
Exhibit No.: A-72 (TKJ-1)
Page: 3 of 4
Witness: TKJoyce
Date: December 2024

Projected O&M Expenses

Line No.		Description	(a) 12 mos. ended 12/31/2023	(b) Projected 12 mos. ending 12/31/2024	(c) Projected 12 mos. ending 12/31/2025	(d) Projected 12 mos. Ending 10/31/2026
1		**COMPRESSION O&M**				
2		**Freedom Compression**	**2,202**	**2,270**	**2,008**	**2,127**
	55%	Labor	1,221	1,258	1,113	1,180
	7%	Materials	154	159	141	149
	20%	Contractor	436	449	398	421
	0%	Non-Labor Overhead	4	4	3	4
	18%	Non-Labor Other	387	399	353	374
3		**Muskegon River Compr**	**2,859**	**3,177**	**2,696**	**2,856**
	79%	Labor	2,251	2,501	2,122	2,249
	-12%	Materials	(342)	(381)	(323)	(342)
	14%	Contractor	409	454	385	408
	0%	Non-Labor Overhead	2	2	2	2
	19%	Non-Labor Other	540	600	509	539
4		**Northville Compression**	**1,144**	**1,085**	**1,105**	**1,171**
	73%	Labor	833	790	805	853
	2%	Materials	23	22	23	24
	7%	Contractor	77	73	75	79
	0%	Non-Labor Overhead	1	1	1	1
	18%	Non-Labor Other	209	199	202	214
5		**Overisel Compression**	**2,333**	**2,275**	**2,254**	**2,389**
	48%	Labor	1,119	1,091	1,081	1,145
	15%	Materials	345	337	334	354
	11%	Contractor	251	245	243	257
	0%	Non-Labor Overhead	1	1	1	1
	26%	Non-Labor Other	617	601	596	632
6		**Ray Compression**	**4,055**	**3,175**	**3,495**	**3,703**
	52%	Labor	2,099	1,643	1,809	1,917
	9%	Materials	359	281	310	328
	24%	Contractor	960	752	828	877
	1%	Non-Labor Overhead	29	23	25	27
	15%	Non-Labor Other	607	475	523	555
7		**St Clair Compression**	**3,055**	**2,907**	**2,775**	**2,940**
	48%	Labor	1,470	1,399	1,335	1,415
	8%	Materials	254	241	230	244
	31%	Contractor	961	915	873	925
	0%	Non-Labor Overhead	7	7	7	7
	12%	Non-Labor Other	362	345	329	349
8		**White Pigeon Compression**	**2,232**	**2,142**	**2,256**	**2,390**
	62%	Labor	1,377	1,321	1,392	1,474
	15%	Materials	328	315	332	351
	13%	Contractor	295	284	299	316
	0%	Non-Labor Overhead	1	1	1	1
	10%	Non-Labor Other	230	221	233	247
		COMPRESSION REBUILDS O&M				
9		**Turbo/Engine Rebuilds**	**(815)**	**-**	**-**	**-**
	-9%	Labor	71	-	-	-
	121%	Materials	(988)	-	-	-
	-11%	Contractor	89	-	-	-
	0%	Non-Labor Overhead	-	-	-	-
	-2%	Non-Labor Other	13	-	-	-
		RENEWABLE NATURAL GAS O&M				
10		**Renewable Natural Gas**	**-**	**-**	**-**	**-**
		Labor	-	-	-	-
		Materials	-	-	-	-
		Contractor	-	-	-	-
		Non-Labor Overhead	-	-	-	-
		Non-Labor Other	-	-	-	-
11		**TOTAL O&M**	**$ 17,880**	**17,030**	**$ 16,590**	**$ 17,577**
		Labor	10,370	10,004	9,658	10,233
		Materials	1,122	975	1,046	1,108
		Contractor	3,390	3,172	3,100	3,284
		Non-Labor Overhead	45	39	40	42
		Non-Labor Other	2,953	2,840	2,746	2,909

Notes:

% breakdown for cost elements is based on 2023 actual
Test Year is based on a monthly cash flow from 2025-2026
2023-Test Year excludes facilities
Line 3 and 9 - 2023 Actual includes ($0.8M) for H-9 Eng rebuild - credit is for parts going back into inventory for future rebuilds
Line 3 and 9 - % breakdown for cost element for Turbo Engine Rebuild Actual 2023 is based on 2023 forecast due to large credit in materials.
Line 3 and 9 - All rebuild costs considered capital after 10/1/2022

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
12 Months Ending October 31, 2026 Gas Compression
and Renewable Natural Gas O&M Expenses
($000)

Case No.: U-21806
Exhibit No.: A-72 (TKJ-1)
Page: 4 of 4
Witness: TKJoyce
Date: December 2024

Line No.	Description	(a) Actual 12 Mos Ended Dec 31, 2023	(b) Base O&M for Merit & Inflation 12 Mos Ended Dec 31, 2023	(c) Merit & Inflation 12 Mos Ending Dec 31, 2024	(d) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	(e) Merit & Inflation 12 Mos Ending Dec 31, 2025	(f) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	(g) Merit & Inflation 9 Mos Ending Oct 31, 2026	(h) Other Adjustments	(i) Projected O&M 12 Mos Ending Oct 31, 2026
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
	COMPRESSION O&M									
1	**Freedom Compression**	**2,202**	**1,588.674**	-	**1,589**	-	**1,589**	-	**(75)**	**2,127**
	Labor	1,221	607.590	-	608	-	608	-	(41)	1,180
	Materials	154	154.276	-	154	-	154	-	(5)	149
	Contractor	436	435.995	-	436	-	436	-	(15)	421
	Non-Labor Overhead	4	3.671	-	4	-	4	-	(0)	4
	Non-Labor Other	387	387.143	-	387	-	387	-	(13)	374
2	**Muskegon River Compr**	**2,859**	**1,203.161**	-	**1,203**	-	**1,203**	-	**(3)**	**2,856**
	Labor	2,251	594.960	-	595	-	595	-	(2)	2,249
	Materials	(342)	(342.448)	-	(342)	-	(342)	-	0	(342)
	Contractor	409	408.760	-	409	-	409	-	(0)	408
	Non-Labor Overhead	2	1.896	-	2	-	2	-	(0)	2
	Non-Labor Other	540	539.994	-	540	-	540	-	(0)	539
3	**Northville Compression**	**1,144**	**764.874**	-	**765**	-	**765**	-	**27**	**1,171**
	Labor	833	454.310	-	454	-	454	-	20	853
	Materials	23	23.298	-	23	-	23	-	1	24
	Contractor	77	77.272	-	77	-	77	-	2	79
	Non-Labor Overhead	1	0.633	-	1	-	1	-	0	1
	Non-Labor Other	209	209.362	-	209	-	209	-	5	214
4	**Overisel Compression**	**2,333**	**1,756.867**	-	**1,757**	-	**1,757**	-	**55**	**2,389**
	Labor	1,119	542.300	-	542	-	542	-	27	1,145
	Materials	345	345.398	-	345	-	345	-	8	354
	Contractor	251	251.460	-	251	-	251	-	6	257
	Non-Labor Overhead	1	0.801	-	1	-	1	-	0	1
	Non-Labor Other	617	616.909	-	617	-	617	-	15	632
5	**Ray Compression**	**4,055**	**2,906.703**	-	**2,907**	-	**2,907**	-	**(352)**	**3,703**
	Labor	2,099	950.510	-	951	-	951	-	(182)	1,917
	Materials	359	359.209	-	359	-	359	-	(31)	328
	Contractor	960	960.196	-	960	-	960	-	(83)	877
	Non-Labor Overhead	29	29.497	-	29	-	29	-	(3)	27
	Non-Labor Other	607	607.290	-	607	-	607	-	(53)	555
6	**St Clair Compression**	**3,055**	**2,186.845**	-	**2,187**	-	**2,187**	-	**(115)**	**2,940**
	Labor	1,470	602.030	-	602	-	602	-	(55)	1,415
	Materials	254	253.742	-	254	-	254	-	(10)	244
	Contractor	961	961.139	-	961	-	961	-	(36)	925
	Non-Labor Overhead	7	7.493	-	7	-	7	-	(0)	7
	Non-Labor Other	362	362.442	-	362	-	362	-	(14)	349
7	**White Pigeon Compression**	**2,232**	**1,380.480**	-	**1,380**	-	**1,380**	-	**158**	**2,390**
	Labor	1,377	525.600	-	526	-	526	-	98	1,474
	Materials	328	328.128	-	328	-	328	-	23	351
	Contractor	295	295.411	-	295	-	295	-	21	316
	Non-Labor Overhead	1	1.085	-	1	-	1	-	0	1
	Non-Labor Other	230	230.255	-	230	-	230	-	16	247
	COMPRESSION REBUILDS O&M									
8	**Turbo/Engine Rebuilds**	**(815)**	-	-	-	-	-	-	**815**	-
	Labor	71	-	-	-	-	-	-	(71)	-
	Materials	(988)	-	-	-	-	-	-	988	-
	Contractor	89	-	-	-	-	-	-	(89)	-
	Non-Labor Overhead	-	-	-	-	-	-	-	-	-
	Non-Labor Other	13	-	-	-	-	-	-	(13)	-
	RENEWABLE NATURAL GAS O&M									
9	**Renewable Natural Gas**	-	-	-	-	-	-	-	-	-
	Labor	-	-	-	-	-	-	-		-
	Materials	-	-	-	-	-	-	-		-
	Contractor	-	-	-	-	-	-	-		-
	Non-Labor Overhead	-	-	-	-	-	-	-		-
	Non-Labor Other	-	-	-	-	-	-	-		-
10	**Total Gas Compression and Renewable Natural Gas O&M Expenses**	**$ 17,880**	**$ 11,788**	**$ -**	**$ 11,788**	**$ -**	**$ 11,788**	**$ -**	**$ (303)**	**$ 17,577**
	Labor	10,370	4,277	-	4,277	-	4,277	-	(137)	10,233
	Material	1,122	1,122	-	1,122	-	1,122	-	(14)	1,108
	Contractor	3,390	3,390	-	3,390	-	3,390	-	(106)	3,284
	Non-Labor Overheads	45	45	-	45	-	45	-	(3)	42
	Non-Labor Other	2,953	2,953	-	2,953	-	2,953	-	(44)	2,909

Notes

Base Labor is all labor cost elements less OM&C & Indirect Labor

		12-Mo Ending 2024	12-Mo Ending 2025	10-Mo Ending 2026
11	Annual merit and inflation rates per WP-HLR-44			
	Annual inflation rates	0.0%	0.0%	0.0%
	Number of months in the period	12	12	10
	Pro-rated inflation rate	0.0%	0.0%	0.0%

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Summary of Actual & Projected Gas O&M Expenses for Lost and Unaccounted for Gas & Company Use Gas

For the Test Year 12 Months Ending October 31, 2026

($000)

Case No.: U-21806
Exhibit No.: A-73 (TKJ-2)
Page: 1 of 1
Witness: TKJoyce
Date: December 2024

Line No.	(a) Description	(b) 2023 Actual	(c) 12 Months Ending October 31, 2026 Projected	(d) Difference	(e) Source
1	**Lost & Unaccounted for Gas Costs (LAUF)**	**21,116**	**12,709**	**$ (8,407)**	WP-HLR-8 line 15 column (c) and Exhibit A-75 (TKJ-4) line 14, column (h)
	Labor	0	0	0	
	Materials	0	0	0	
	Contractor	0	0	0	
	Non-Labor Overhead	0	0	0	
	Non-Labor Other	0	0	0	
	Other: Cost of Goods Sold	21,116	12,709	(8,407)	
2	**Company Use Gas**	**(820)**	**5,502**	**6,322**	WP-TKJ-3 and Exhibit A-75 (TKJ-4) line 21, column (h)
	Labor	0	0	0	
	Materials	0	0	0	
	Contractor	0	0	0	
	Non-Labor Overhead	0	0	0	
	Non-Labor Other	(820)	5,502	6,322	
3	**Total Expense**	**$ 20,296**	**$ 18,211**	**$ (2,085)**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Gas Loss Percentage
August 2019 through July 2024

Case No.: U-21806
Exhibit No.: A-74 (TKJ-3)
Page: 1 of 1
Witness: TKJoyce
Date: December 2024

Line No.	(a) Sendout Period	(b) Sendout [1] MMcf	(c) Billed Throughput [2] MMcf	(d) Gas Loss Before Inventory Adjustment MMcf	(e) Inventory Adjustment MMcf	(f) Total Gas Loss MMcf	(g) Gas Loss [3] Percentage
1	August 2019 - July 2020	293,511	288,088	5,423	494	5,917 [4]	2.02%
2	August 2020 - July 2021	290,731	285,525	5,206	-	5,206	1.79%
3	August 2021 - July 2022	308,734	304,936	3,798	-	3,798	1.23%
4	August 2022 - July 2023	296,564	291,618	4,946	109	5,055 [5]	1.70%
5	August 2023 - July 2024	277,138	270,847	6,291	-	6,291	2.27%
6	Total - August 2019 - July 2024	1,466,678	1,441,014	25,664	603	26,267	1.79%

[1] Sendout for column (b) obtained from Gas Control Operations Summary report.
[2] Billed Throughput volumes (Sales plus End - User transportation) for column (c) obtained from the Accounting Department.
[3] Gas Loss Percentage=Total Gas Loss [Column (f)] / Sendout[Column (b)].
[4] Includes an inventory adjustment of 494 MMcf for losses at Overisel field recognized between August 2019 and July 2020.
[5] Includes an inventory adjustment of 80 MMcf for losses at Ira field and 29 MMcf for losses at Northville Reef recognized between August 2022 and July 2023.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Allowance for Gas Use and Losses
For the Test Year 12 Months Ending October 31, 2026

Case No.: U-21806
Exhibit No.: A-75 (TKJ-4)
Page: 1 of 1
Witness: TKJoyce
Date: December 2024

Line No.	(a) Description	(b) Transportation Gas-In-Kind Mcf	(c) Company Use Net Of Gas-In-Kind Mcf	(d) LAUF and Company Use Adjustment Mcf	(e) Transportation Offset Mcf	(f) Net LAUF and Company Use Mcf	(g) Gas Rates	(h) Total LAUF and Company Use Gas Expenses	(i) Source
1	**Calculation of Allowance for Use & Losses**								
2	Total Sendout/Throughput			307,736,000					Exhibit A-15 (MA-6), Schedule E-2, line 13, column (g)
3	Five-Year Average LAUF Percentage			1.79%					Exhibit A-74 (TKJ-3), line 6, column (g)
4	Lost and Unaccounted for Gas Volume			5,511,299					Line 2 x line 3
5	Lost and Unaccounted for Gas Volume			5,511,299					From line 4
6	Fuel Gas Volume			2,386,000					WP-TKJ-9, line 25, column "n"
7	Total LAUF & Fuel Gas Volume			7,897,299					Line 5 + line 6
8									
9	Total Sendout/Throughput			307,736,000					Line 2
10									
11	Allowance for Use and Losses %			2.57%					Line 7 divided by line 9
12									
13	**Calculation of Consumers Energy LAUF & Co. Use**								
14	Lost and Unaccounted for Gas Volume			5,511,299	-1,655,071	3,856,229	$ 3.296	* **$ 12,708,973**	WP-TKJ-12, line 35, column "n" for gas rate
15	Company Use Gas Volume		2,386,000						WP-TKJ-9, line 25, column "n"
16									
17	Transportation Volume	81,455,000							Exhibit A-15 (MA-7), Schedule E-3, line 39, sum of columns (h), (i), (j) , and (k).
18	Allowance for Use and Losses Percentage	2.57%							From line 11
19	Transportation Gas-in-Kind Volume	**2,090,345**							Line 17 x line 18
20	Other Gas-in-Kind Volume	281,253							WP-TKJ-15, line 15, column "v"
21	Net Company Use Gas Volume		**2,386,000**	2,386,000	-716,528	1,669,472	$ 3.296	* **$ 5,502,080**	WP-TKJ-12, line 35, column "n" for gas rate
22									
23	Total LAUF and Company Use Gas Adj			7,897,299				**$ 18,211,053**	Line 14 + line 21

* 12 month Average of Cost of Gas Sold

Schedule: B-5.7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Gas Compression and Gas Storage
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (TKJ-5)
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Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Period 12 Mos Ending 12/31/2024	(d) Projected Bridge Period 10 Mos Ending 10/31/2025	(e) Projected Bridge Period 22 Mos Ending 10/31/2025	(f) Projected Test Year 12 Mos Ending 10/31/2026
1	Freedom Upgrade Project	8,413	726	0	726	0
2	Compression	39,197	62,267	44,597	106,864	66,198
3	Storage	6,765	28,548	35,690	64,238	25,234
4	New Well	11,403	17,202	28,004	45,205	32,296
5	Well Rehabilitation	31,031	23,681	22,341	46,022	7,498
6	Storage Pipeline Replacement	3,550	14,836	24,398	39,233	20,930
7	Well Data Acquisition	239	203	3,671	3,875	4,568
8	Riverside Field Retirement	12,449	25,439	23,756	49,195	3,504
9	Safety Valve Installation	0	2,438	1,599	4,037	1,811
10	Total Capital Expenditures	113,046	175,339	184,056	359,395	162,039

		Projected 10 Mos Ending 10/31/2024	Projected 12 Mos Ending 10/31/2025	Projected 12 Mos Ending 10/31/2026	Projected 34 Mos Ending 10/31/2026
11	Freedom Upgrade Project	579	147	0	726
12	Compression	39,551	67,312	66,198	173,062
13	Storage	23,302	40,935	25,234	89,472
14	New Well	10,961	34,244	32,296	77,501
15	Well Rehabilitation	23,303	22,720	7,498	53,521
16	Storage Pipeline Replacement	11,961	27,272	20,930	60,163
17	Well Data Acquisition	38	3,837	4,568	8,443
18	Riverside Field Retirement	22,084	27,111	3,504	52,699
19	Safety Valve Installation	2,527	1,510	1,811	5,848
20	Total Capital Expenditures	134,307	225,089	162,039	521,434

Schedule: B-5.7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Gas Compression and Gas Storage
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (TKJ-5)
Schedule: B-5.7
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Witness: TKJoyce
Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Period 12 Mos Ending 12/31/2024	(d) Projected Bridge Period 10 Mos Ending 10/31/2025	(e) Projected Bridge Period 22 Mos Ending 10/31/2025	(f) Projected Test Year 12 Mos Ending 10/31/2026
1	Freedom Upgrade Project	8,413	726	0	726	0
2	Freedom Compression	239	232	424	656	153
3	Muskegon River Compression	4,210	21,435	14,576	36,011	14,126
4	Northville Compression	2,382	2,786	3,890	6,676	11,055
5	Overisel Compression	28,178	24,925	17,025	41,950	15,561
6	Ray Compression	1,657	7,010	3,563	10,573	4,476
7	St Clair Compression	2,074	3,610	3,623	7,234	14,502
8	White Pigeon Compression	457	2,268	1,497	3,765	6,324
9	Marion Storage Fields	2,547	1,562	3,082	4,644	13,501
10	Northville Storage Field	1,382	8,453	25,351	33,804	4,672
11	Overisel Storage Fields	1,500	4,877	1,742	6,619	4,526
12	Ray Storage Fields	81	4,061	5,215	9,275	791
13	St Clair Storage Fields	1,255	9,595	301	9,896	1,743
14	Storage New Wells	11,403	17,202	28,004	45,205	32,296
15	Well Rehabilitation	31,031	23,681	22,341	46,022	7,498
16	Storage Pipeline Replacement	3,550	14,836	24,398	39,233	20,930
17	Well Data Acquisition	239	203	3,671	3,875	4,568
18	Riverside Field Retirement	12,449	25,439	23,756	49,195	3,504
19	Safety Valve Installation	0	2,438	1,599	4,037	1,811
20	Total Capital Expenditures	113,046	175,339	184,056	359,395	162,039

Unless noted otherwise, capital “other” costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.). This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were

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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Gas Compression and Gas Storage
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (TKJ-5)
Schedule: B-5.7
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Witness: TKJoyce
Date: December 2024

Line No	Description	Historical Year 12 Mos Ended 12/31/2023	Projected Bridge Year 12 Mos Ending 12/31/2024	Projected Bridge Year 10 Mos Ending 10/31/2025	Projected Bridge Year 22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
	(a)	(b)	(c)	(d)	(e)	(f)
1	**Freedom Upgrade Project**	**8,413**	**726**	**0**	**726**	**0**
4%	Labor	337	31	0	31	0
15%	Capitalized Engineering/Supv	1,245	107	0	107	0
1%	Materials	90	8	0	8	0
74%	Contractor	6,265	539	0	539	0
0%	Non-Labor Overhead	12	1	0	1	0
6%	Non-Labor Other	464	40	0	40	0
2	**Freedom Compression**	**239**	**232**	**424**	**656**	**153**
5%	Labor	8	11	19	30	7
1%	Capitalized Engineering/Supv	0	3	5	7	2
80%	Materials	224	186	340	527	123
9%	Contractor	(4)	22	40	61	14
0%	Non-Labor Overhead	0	0	0	0	0
5%	Non-Labor Other	11	11	20	30	7
3	**Muskegon River Compression**	**4,210**	**21,435**	**14,576**	**36,011**	**14,126**
11%	Labor	629	2,336	1,589	3,925	1,540
12%	Capitalized Engineering/Supv	593	2,527	1,718	4,246	1,666
5%	Materials	153	1,039	707	1,746	685
65%	Contractor	2,451	13,835	9,408	23,243	9,118
0%	Non-Labor Overhead	15	38	26	64	25
8%	Non-Labor Other	369	1,659	1,128	2,788	1,094
4	**Northville Compression**	**2,382**	**2,786**	**3,890**	**6,676**	**11,055**
11%	Labor	248	295	412	707	1,171
13%	Capitalized Engineering/Supv	354	361	504	865	1,432
10%	Materials	177	288	403	691	1,144
58%	Contractor	1,427	1,627	2,271	3,898	6,455
0%	Non-Labor Overhead	5	4	6	10	17
8%	Non-Labor Other	170	211	295	505	837
5	**Overisel Compression**	**28,178**	**24,925**	**17,025**	**41,950**	**15,561**
5%	Labor	1,086	1,191	814	2,005	744
13%	Capitalized Engineering/Supv	4,085	3,316	2,265	5,581	2,070
23%	Materials	7,533	5,855	3,999	9,855	3,655
50%	Contractor	13,676	12,463	8,513	20,976	7,781
0%	Non-Labor Overhead	(4)	7	5	11	4
8%	Non-Labor Other	1,803	2,092	1,429	3,522	1,306

Unless noted otherwise, capital “other” costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and
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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Gas Compression and Gas Storage
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (TKJ-5)
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Witness: TKJoyce
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026
6	**Ray Compression**	**1,657**	**7,010**	**3,563**	**10,573**	**4,476**
7%	Labor	77	518	263	782	331
11%	Capitalized Engineering/Supv	227	760	386	1,146	485
7%	Materials	45	487	247	734	311
68%	Contractor	1,205	4,772	2,425	7,198	3,047
0%	Non-Labor Overhead	1	20	10	31	13
6%	Non-Labor Other	103	452	230	682	289
7	**St Clair Compression**	**2,074**	**3,610**	**3,623**	**7,234**	**14,502**
7%	Labor	148	262	262	524	1,051
12%	Capitalized Engineering/Supv	295	450	452	902	1,807
16%	Materials	83	588	591	1,179	2,364
57%	Contractor	1,418	2,074	2,081	4,155	8,329
0%	Non-Labor Overhead	0	8	8	16	32
6%	Non-Labor Other	130	229	230	459	920
8	**White Pigeon Compression**	**457**	**2,268**	**1,497**	**3,765**	**6,324**
17%	Labor	63	385	254	639	1,073
13%	Capitalized Engineering/Supv	64	284	187	471	791
3%	Materials	14	68	45	113	191
55%	Contractor	277	1,257	830	2,087	3,505
0%	Non-Labor Overhead	0	1	0	1	2
12%	Non-Labor Other	38	274	181	454	763
9	**Marion Storage Fields**	**2,547**	**1,562**	**3,082**	**4,644**	**13,501**
7%	Labor	168	103	203	305	888
14%	Capitalized Engineering/Supv	363	216	427	643	1,869
13%	Materials	338	200	395	596	1,732
58%	Contractor	1,471	901	1,778	2,679	7,788
0%	Non-Labor Overhead	6	4	7	11	31
9%	Non-Labor Other	201	138	272	410	1,193
10	**Northville Storage Field**	**1,382**	**8,453**	**25,351**	**33,804**	**4,672**
5%	Labor	83	460	1,381	1,841	254
8%	Capitalized Engineering/Supv	132	689	2,065	2,753	381
0%	Materials	0	0	0	0	0
63%	Contractor	1,105	5,353	16,054	21,407	2,959
0%	Non-Labor Overhead	0	0	0	0	0
23%	Non-Labor Other	62	1,951	5,852	7,803	1,078

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This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month (Jan 2023 - Jun 2024) average actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop these cost projections.

Schedule: B-5.7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Gas Compression and Gas Storage
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-12 (TKJ-5)
Schedule: B-5.7
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Witness: TKJoyce
Date: December 2024

Line No	Description	Historical Year 12 Mos Ended 12/31/2023	Projected Bridge Year 12 Mos Ending 12/31/2024	Projected Bridge Year 10 Mos Ending 10/31/2025	Projected Bridge Year 22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
	(a)	(b)	(c)	(d)	(e)	(f)
11	**Overisel Storage Fields**	**1,500**	**4,877**	**1,742**	**6,619**	**4,526**
11%	Labor	143	528	189	717	490
14%	Capitalized Engineering/Supv	220	660	236	896	612
6%	Materials	81	309	111	420	287
57%	Contractor	932	2,793	997	3,790	2,592
0%	Non-Labor Overhead	1	5	2	7	5
12%	Non-Labor Other	123	581	208	789	540
12	**Ray Storage Fields**	**81**	**4,061**	**5,215**	**9,275**	**791**
5%	Labor	22	193	247	440	38
10%	Capitalized Engineering/Supv	11	417	535	952	81
55%	Materials	0	2,226	2,859	5,086	434
23%	Contractor	38	952	1,223	2,175	186
0%	Non-Labor Overhead	0	10	12	22	2
6%	Non-Labor Other	10	263	338	601	51
13	**St Clair Storage Fields**	**1,255**	**9,595**	**301**	**9,896**	**1,743**
8%	Labor	204	803	25	828	146
10%	Capitalized Engineering/Supv	176	1,005	31	1,036	183
21%	Materials	374	2,000	63	2,063	363
54%	Contractor	371	5,165	162	5,327	938
0%	Non-Labor Overhead	2	25	1	26	5
6%	Non-Labor Other	127	597	19	616	108
14	**Storage New Wells**	**11,403**	**17,202**	**28,004**	**45,205**	**32,296**
4%	Labor	366	686	1,116	1,801	1,287
13%	Capitalized Engineering/Supv	1,739	2,309	3,760	6,069	4,336
7%	Materials	858	1,285	2,092	3,378	2,413
62%	Contractor	7,471	10,670	17,370	28,041	20,033
0%	Non-Labor Overhead	5	7	12	20	14
13%	Non-Labor Other	964	2,244	3,653	5,897	4,213
15	**Well Rehabilitation**	**31,031**	**23,681**	**22,341**	**46,022**	**7,498**
5%	Labor	1,668	1,300	1,226	2,526	412
14%	Capitalized Engineering/Supv	4,588	3,259	3,074	6,333	1,032
2%	Materials	589	493	465	958	156
71%	Contractor	21,722	16,842	15,889	32,731	5,333
0%	Non-Labor Overhead	24	18	17	36	6
7%	Non-Labor Other	2,442	1,769	1,669	3,438	560

Unless noted otherwise, capital “other” costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and
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Schedule: B-5.7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Gas Compression and Gas Storage
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.:	U-21806
Exhibit No.:	A-12 (TKJ-5)
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Witness:	TKJoyce
Date:	December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026
16	**Storage Pipeline Replacement**	**3,550**	**14,836**	**24,398**	**39,233**	**20,930**
8%	Labor	439	1,182	1,944	3,127	1,668
12%	Capitalized Engineering/Supv	518	1,761	2,896	4,657	2,485
34%	Materials	824	5,023	8,261	13,284	7,087
37%	Contractor	1,480	5,493	9,033	14,526	7,749
0%	Non-Labor Overhead	14	46	75	121	65
9%	Non-Labor Other	275	1,330	2,187	3,518	1,877
17	**Well Data Acquisition**	**239**	**203**	**3,671**	**3,875**	**4,568**
33%	Labor	76	67	1,213	1,280	1,509
14%	Capitalized Engineering/Supv	33	28	502	530	624
28%	Materials	71	57	1,037	1,095	1,291
10%	Contractor	23	21	382	403	475
0%	Non-Labor Overhead	0	0	0	0	0
15%	Non-Labor Other	35	30	538	568	670
18	**Riverside Field Retirement**	**12,449**	**25,439**	**23,756**	**49,195**	**3,504**
8%	Labor	831	1,933	1,805	3,739	266
24%	Capitalized Engineering/Supv	3,203	6,112	5,708	11,820	842
13%	Materials	2,436	3,312	3,093	6,406	456
36%	Contractor	3,791	9,105	8,503	17,609	1,254
0%	Non-Labor Overhead	16	71	66	137	10
19%	Non-Labor Other	2,172	4,905	4,580	9,485	676
19	**Safety Valve Installation**	**0**	**2,438**	**1,599**	**4,037**	**1,811**
12%	Labor	0	292	191	483	217
8%	Capitalized Engineering/Supv	0	207	136	343	154
0%	Materials	0	0	0	0	0
74%	Contractor	0	1,806	1,184	2,989	1,341
0%	Non-Labor Overhead	0	0	0	0	0
5%	Non-Labor Other	0	134	88	222	99
20	Total Capital	113,046	175,339	184,056	359,395	162,039
	Labor	6,594	12,576	13,154	25,731	13,090
	Capitalized Engineering/Supv	17,847	24,469	24,886	49,355	20,851
	Materials	13,891	23,428	24,709	48,138	22,692
	Contractor	65,117	95,690	98,143	193,833	88,897
	Non-Labor Overhead	98	264	248	512	228
	Non-Labor Other	9,499	18,911	22,916	41,827	16,281

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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Storage Well Rehabilitation Program Detail

Case No.: U-21806
Exhibit No.: A-76 (TKJ-6)
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Line No.	Year	Historical 2017 (Actuals)	2018 (Actuals)	2019 (Actuals)	2020 (Actuals)	2021 (Actuals)	2022 (Actuals)	2023 (Actuals)	Projected 2024	2025	2026	2027	Totals
1													
2	Number of wells rehabbed	123	109	83	66	71	68	73	58	61	13	0	725
3		$ 120,963	$ 200,833	$ 249,847	$ 301,024	$ 420,311	$ 541,108	$ 422,244	$ 402,486	$ 408,954	$ 367,525		
4													
5													
6													
7	**PROGRAM LEVEL - Spend Allocation**												
8													
9													
10	*CE Labor*	2,595,361	4,526,085	5,033,060	3,176,888	3,106,553	3,723,063	4,743,083	3,592,426	3,883,423	743,753	-	35,123,696
11	*Outside Services - Admin*	701,828	631,406	702,272	1,858,605	2,156,299	2,273,660	1,781,586	1,349,305	1,458,683	279,367	115,733	13,308,745
12	**Total Labor**	3,297,189	5,157,491	5,735,332	5,035,493	5,262,852	5,996,723	6,524,670	4,941,731	5,342,106	1,023,120	115,733	48,432,441
13													
14	*Wellheads*	1,573,977	738,934	226,592	105,000	143,000	610,620	727,301	550,826	595,477	114,046	-	5,385,772
15	*Packers*	62,015	54,450	61,780	64,000	94,255	78,611	88,846	67,288	72,743	13,932	-	657,921
16	*Tubing*	201,013	70,000	40,894	136,000	420,763	1,376,319	480,495	363,906	393,405	75,345	-	3,558,141
17	*Equipment Mats*	317,584	342,589	160,831	758,858	156,070	312,107	438,342	331,981	358,892	68,735	-	3,245,989
18	*Other Misc*	109,696	1,152,266	492,581	90,940	393,889	1,222,257	740,893	561,120	606,605	116,177	-	5,486,424
19	**Total Materials**	2,264,285	2,358,239	982,677	1,154,798	1,207,977	3,599,914	2,475,878	1,875,121	2,027,123	388,234	-	18,334,246
20													
21	*Civil/Site Prep*	2,022,147	3,174,621	2,313,387	2,353,615	2,995,182	3,719,058	3,548,418	2,687,277	2,905,113	556,387	-	26,275,206
22	*Well Consultants*	977,358	2,201,074	1,191,708	1,057,500	1,904,952	1,725,433	1,938,813	1,468,296	1,587,319	304,003	-	14,356,457
23	*Logging*	2,542,905	2,649,112	2,020,394	1,875,583	2,176,537	2,080,244	2,856,365	2,163,173	2,338,525	447,874	-	21,150,712
24	*Wellhead Technician / Welding*	417,012	476,722	538,578	588,202	1,386,443	1,039,968	951,836	720,841	779,274	149,247	-	7,048,122
25	*Painting*	149,340	231,940	544,968	305,040	782,247	1,430,818	737,242	558,326	603,585	115,599	-	5,459,104
26	*Wellhead Assessment*	272,044	-	-	-	-	-	58,229	44,098	47,673	9,130	-	431,174
27	*Cathodic*	-	27,708	63,170	14,170	-	40,673	31,191	23,621	25,536	4,891	-	230,960
28	*Downhole work*	3,260,928	6,052,907	7,885,993	7,483,163	14,069,796	14,589,169	11,417,508	8,646,671	9,347,589	1,790,250	-	84,543,975
	Misc	-	-	-	-	729,394	3,256,292	853,111	646,075	698,448	133,767	-	6,317,086
29	**Total Construction**	9,641,734	14,814,084	14,558,199	13,677,273	24,044,551	27,881,655	22,392,714	16,958,379	18,333,062	3,511,147	-	165,812,797
30													
31	*Cost Of Removal*	(324,699)	(438,981)	(538,889)	-	(673,314)	(682,924)	(569,443)	(431,035)	(756,069)	(144,675)	(3,472)	(4,563,501)
32													
33	**CURRENT PROGRAM LEVEL TOTAL (2017-23actuals, 2024-2027 estimates)**	**$ 14,878,509**	**$ 21,890,833**	**$ 20,737,319**	**$ 19,867,564**	**$ 29,842,066**	**$ 36,795,368**	**$ 30,823,818**	**$ 23,344,196**	**$ 24,946,222**	**$ 4,777,827**	**$ 112,261**	**$ 228,015,983**
34													
35													
36	**PROGRAM LEVEL - Cost Element Breakdown**												
37													
38	Labor	2,595,361	4,526,085	5,033,060	3,176,888	3,106,553	3,723,063	4,743,083	3,592,426	3,883,423	743,753	-	35,123,696
39	Material	2,264,285	2,358,239	982,677	1,154,798	1,207,977	3,599,914	2,475,878	1,875,121	2,027,123	388,234	-	18,334,246
40	Business Expenses	-	-	-	-	-	-	-	-	-	-	-	-
41	Contractors	10,343,562	15,445,490	15,260,470	15,535,878	26,200,850	30,155,315	24,174,300	18,307,685	19,791,745	3,790,514	115,733	179,121,542
42	Contingency	-	-	-	-	-	-	-	-	-	-	-	-
43	Cost of Removal	(324,699)	(438,981)	(538,889)	-	(673,314)	(682,924)	(569,443)	(431,035)	(756,069)	(144,675)	(3,472)	(4,563,501)
44	**CURRENT PROGRAM LEVEL TOTAL (2017-23 actuals, 2024-2027 estimates)**	**$ 14,878,509**	**$ 21,890,833**	**$ 20,737,319**	**$ 19,867,564**	**$ 29,842,066**	**$ 36,795,368**	**$ 30,823,818**	**$ 23,344,196**	**$ 24,946,222**	**$ 4,777,827**	**$ 112,261**	**$ 228,015,983**

Unless noted otherwise, capital "other" costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Storage Well Rehabilitation Program
2025 Projected Expeditures

Case No.: U-21806
Exhibit No.: A-76 (TKJ-6)
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Date: Decemeber 2024

Program	Well	Scope Code		Scope	Logging	Outlier Y/N	Cost Estimate (Based on 2023 Actuals)	Labor For Loadings Calc	OSS For Loadings Calc
WRH	BD-139	RPLS	WRH	RPLS, acidize, AM (notify EGLE/EPA prior to work)			182,733	14,021	168,712
WRH	C-246	LUT	WRH	LUT, AM			156,351	18,667	137,684
WRH	C-247	LUT	WRH	LUT, AM			156,351	18,667	137,684
WRH	C-249	LUT	WRH	LUT, AM			156,351	18,667	137,684
WRH	C-351	LUT	WRH	LUT, AM			156,351	18,667	137,684
WRH	C-389	LUT	WRH	LU, AM, FC/WV			156,351	18,667	137,684
WRH	C-409	RPLUS	WRH	RPLUS, AM			145,051	6,745	138,306
WRH	C-463	LUT	WRH	LU, AM, FC/WV			156,351	18,667	137,684
WRH	C-714	RPLS	WRH	RPLS, AM			182,733	14,021	168,712
WRH	C-932	Misc	WRH	Log, clean out, AM			90,999	8,981	82,018
WRH	FC-103	Misc	WRH	Clean out, log		Wetlands	140,999	8,981	132,018
WRH	FC-104	Misc	WRH	Clean out, log, WH seals		Wetlands	140,999	8,981	132,018
WRH	H-01	Misc	WRH	Clean out, log, WH seals			90,999	8,981	82,018
WRH	H-03	RPLS	WRH	RPLS (squeezed perfs)			182,733	14,021	168,712
WRH	H-04	Misc	WRH	Clean out, log			90,999	8,981	82,018
WRH	H-06	Misc	WRH	Clean out, log			90,999	8,981	82,018
WRH	H-07	Misc	WRH	Clean out, log			90,999	8,981	82,018
WRH	H-08	Misc	WRH	Clean out, log			90,999	8,981	82,018
WRH	H-09	Misc	WRH	Clean out, log			90,999	8,981	82,018
WRH	H-103	CT	WRH	CT: CLAF, perf		Wetlands	379,756	23,053	356,703
WRH	H-104	CT	WRH	CT: CLAF (4pt), plugback, perf, retrieve SSSV (FOU fed of FL)		Wetlands/Large Acid	389,591	23,053	366,538
WRH	H-106	CT	WRH	CT: CLAF, retrieve SSSV		Wetlands	379,756	23,053	356,703
WRH	H-112	CT	WRH	CT: CLAF, retrieve SSSV		Wetlands	379,756	23,053	356,703
WRH	H-202	CT	WRH	CT: Replace WH seal, CLAF (4pt), AD			329,756	23,053	306,703
WRH	I-202	CT	WRH	CT: CLAF (4pt)		Large Acid	339,503	23,053	316,450
WRH	MGSCo 34-22-1	RPLS	WRH	RPLS, acidize, AM (notify EGLE/EPA prior to work)			182,733	14,021	168,712
WRH	O-118	LAT W/ WH	WRH	LAT, WH			252,836	18,543	234,293
WRH	O-129	LAT W/ WH	WRH	LAT, solvent, Wellhead			252,836	18,543	234,293
WRH	O-135	LAT W/ WH	WRH	LAT, Wellhead			252,836	18,543	234,293
WRH	O-137	LAT	WRH	LAT, solvent, WH Seal			211,163	3,738	207,425
WRH	O-179	LAT W/ WH	WRH	LAT, solvent, wellhead			252,836	18,543	234,293
WRH	O-186	LAT W/ WH	WRH	LAT, solvent, WH			252,836	18,543	234,293
WRH	O-200	LAT W/ WH	WRH	LAT, solvent, WH			252,836	18,543	234,293
WRH	O-202	LAT W/ WH	WRH	LAT, solvent, WH			252,836	18,543	234,293
WRH	O-207	LAT	WRH	LAT, solvent, WH Seal			211,163	3,738	207,425
WRH	O-212	LAT	WRH	LAT, WH Seal			211,163	3,738	207,425
WRH	O-213	LAT W/ WH	WRH	LAT, solvent, WH			252,836	18,543	234,293
WRH	O-229	LAT W/ WH	WRH	LAT, solvent, wellhead			252,836	18,543	234,293
WRH	O-235	LAT	WRH	LAT, WH Seal			211,163	3,738	207,425
WRH	O-237	LAT W/ WH	WRH	LAT, solvent, Wellhead			252,836	18,543	234,293
WRH	O-246	Misc	WRH	Log, cleanout, wellhead, remove well line			90,999	8,981	82,018
WRH	O-277	LAT W/ WH	WRH	LAT, solvent, Wellhead			252,836	18,543	234,293
WRH	P-102	CT	WRH	CT: CLAF, retrieve SSSV		Large Acid	340,601	23,053	317,548
WRH	P-105	CT	WRH	CT: CLAF, retrieve SSSV		Wetlands	379,756	23,053	356,703
WRH	P-106	CT	WRH	CT: CLAF, retrieve SSSV		Wetlands	379,756	23,053	356,703
WRH	P-201	CT	WRH	CT: CLAF (4pt)		Wetlands/Large Acid	390,293	23,053	367,240
WRH	R-106	CT	WRH	CT: CLAF (4pt), Perf			329,756	23,053	306,703
WRH	R-108	CT	WRH	CT: CLAF			329,756	23,053	306,703
WRH	R-112	CT	WRH	CT: CLAF			329,756	23,053	306,703
WRH	R-125	Misc	WRH	Clean out, log, WH seals, AM			90,999	8,981	82,018
WRH	R-206	CT	WRH	CT: CLAF		Large Acid	341,259	23,053	318,206
WRH	R-301	CT	WRH	CT: CLAF (4pt), WH seals, AM			329,756	23,053	306,703
WRH	R-311	CT	WRH	CT: CLAF (4pt), AM			329,756	23,053	306,703
WRH	R-503	CT	WRH	CT: CLAF (4pt)		Large Acid	338,976	23,053	315,923
WRH	R-505	CT	WRH	CT: CLAF (4pt), Replace WH seals		Wetlands	329,756	23,053	306,703
WRH	S-308	LAT W/ WH	WRH	LAT, WH			252,836	18,543	234,293
WRH	S-310	LAT W/ WH	WRH	LAT, solvent, wellhead			252,836	18,543	234,293
WRH	SC-101	CT RIG	WRH	Snubbing unit (potential)/CT: pull tubing (rig/snubbing unit), CLAF (4pt), set tubing with rig or snubbing unit (perform nodal analy			294,674	29,065	265,610
WRH	W-618	Misc	WRH	Cleanout, Log, AM			90,999	8,981	82,018
WRH	O-178	Misc	WRH	Concter to Obs Well			90,999	8,981	82,018
WRH	O-222	Misc	WRH	Concter to Obs Well			90,999	8,981	82,018
						WRH	**13,870,573**	**991,604**	**12,878,969**

Row Labels	Average of Total	Average of Internal	Average of External
CT	**329,756**	**23,053**	**306,703**
CT RIG	**294,674**	**29,065**	**265,610**
LAT	**211,163**	**3,738**	**207,425**
LAT W/ WH	**252,836**	**18,543**	**234,293**
LU	**166,739**	**25,712**	**141,027**
LUT	**156,351**	**18,667**	**137,684**
Misc	**90,999**	**8,981**	**82,018**
PA	**165,019**	**8,453**	**156,565**
RPLS	**182,733**	**14,021**	**168,712**
RPLUS	**145,051**	**6,745**	**138,306**

WRH	Labor	N.Labor	Total
Cost Per Well	991,604	12,878,969	13,870,573
Internal Labor	483,524	1,545,333	2,028,857
External Allocations		2,027,996	2,027,996
Carryover		1,713,110	1,713,110
Pull ahead Civil Pads		100,000	100,000
Flow Testing		170,000	170,000
Materials		260,135	260,135
Lab Services		32,000	32,000
Pre-Fab Riser	76,560	63,637	140,197
	1,551,688	**18,791,181**	**20,342,868**
5% Allowance, 3% Inflation			1,627,429
			21,970,298
E&S			2,614,465
Labor			1,126,528
less COR			765,069
			24,946,222

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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Storage Well Rehabilitation Program
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Program	Well	Scope Code		Scope	Logging	Outlier Y/N	Cost Estimate (Based on 2023 Cost Loading)	Labor For Loadings Calc	OSS For Loadings Calc
WRH	C-367	Misc	WRH	Remediated in 2019. Remove tubing, log and install tubing - need one more log, AM			90,999	8,981	82,018
WRH	W-207	LUT	WRH	LUT, AM (wellfile shows tubing)			156,351	18,667	137,684
WRH	W-235	LUT	WRH	LUT, spot acid, perf, possible acidizing, AM			156,351	18,667	137,684
WRH	W-297	LUT	WRH	LU, AM			156,351	18,667	137,684
WRH	W-374	Misc	WRH	Log, SL Cleanout, AM			90,999	8,981	82,018
WRH	W-388	LUT	WRH	LU, AM			156,351	18,667	137,684
WRH	W-429	LUT	WRH	LU, perf gun fish, AM			156,351	18,667	137,684
WRH	W-431	LUT	WRH	LU, SL Cleanout, AM			156,351	18,667	137,684
WRH	W-457	RPLS	WRH	RPLS - Need more logs			182,733	14,021	168,712
WRH	W-599	LUT	WRH	LU, AM			156,351	18,667	137,684
WRH	W-657	RPLS	WRH	RPLS, disconnect flow line and remove well line (convert to observation well), AM			182,733	14,021	168,712
WRH	W-674	RPLUS	WRH	RPLUS (possible underreaming, previously underreamed to 6.5"), AM			145,051	6,745	138,306
WRH	W-929	Misc	WRH	Log, SL Cleanout, AM			90,999	8,981	82,018
						WRH	1,877,972	192,396	1,685,576

Row Labels	Average of Total	Average of Internal	Average of External
CT	**329,756**	**23,053**	**306,703**
CT RIG	**294,674**	**29,065**	**265,610**
LAT	**211,163**	**3,738**	**207,425**
LAT W/ WH	**252,836**	**18,543**	**234,293**
LU	**166,739**	**25,712**	**141,027**
LUT	**156,351**	**18,667**	**137,684**
Misc	**90,999**	**8,981**	**82,018**
PA	**165,019**	**8,453**	**156,565**
RPLS	**182,733**	**14,021**	**168,712**
RPLUS	**145,051**	**6,745**	**138,306**

Rehab	Labor	N.Labor	Total	13
Cost Per Well	192,396	1,685,576	1,877,972	
Internal Labor	227,437	726,886	954,323	
External Allocations		441,758	441,758	
Carryover		100,000	100,000	
Pull ahead Civil Pads				
Flow Testing		272,000	272,000	
Materials		13,000	13,000	
NDT		12,000	12,000	
Pre-Fab Riser	28,710	23,864	52,574	
	448,544	**3,275,083**	**3,723,627**	
9% Inflation			335,126	
			4,058,753	
E&S			499,227	
Labor			264,523	
AFUDC			100,000	
			4,922,503	
less COR			144,675	
Total Capital			**4,777,828**	

MICHIGAN PUBLIC SERVICE COMMISSION
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	2026 Wells	
WRH Carryover	**20**	
Restoration	**5,000**	100,000
		100,000
E&S		12,300
Labor		3,433
		115,733
less COR		3,472
Total Capital		**112,261**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Storage Well Rehabilitation Program
2024 Scope Averages for Cost Projection

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Well	Scope	Total	Internal	External
FC-102	CT	355,798	19,420	336,378
H-101	CT	351,189	12,780	338,409
H-102	CT	360,352	12,070	348,282
H-105	CT	339,086	16,580	322,506
H-110	CT	314,569	12,070	302,499
H-111	CT	311,339	61,360	249,979
I-102	CT	312,543	13,740	298,803
P-104	CT	363,155	14,200	348,955
P-202	CT	370,998	64,200	306,798
P-203	CT	389,099	14,200	374,899
P-205	CT	378,969	14,200	364,769
R-123	CT	305,673	31,220	274,454
R-202	CT	338,448	21,580	316,868
R-302	CT	238,174	20,410	217,764
R-307	CT	264,487	20,410	244,077
R-312	CT	282,223	20,410	261,813
H-107	CT RIG	365,081	37,170	327,911
O-304	CT RIG	431,462	14,805	416,657
R-118	CT RIG	365,104	28,278	336,826
W-1000	CT RIG	279,559	21,905	257,654
W-1001	CT RIG	300,398	26,980	273,418
W-1002	CT RIG	317,444	40,720	276,724
W-982	CT RIG	238,133	29,110	209,023
W-983	CT RIG	238,094	29,110	208,984
W-984	CT RIG	261,353	29,110	232,243
W-985	CT RIG	257,613	32,305	225,308
W-995	CT RIG	225,275	26,980	198,295
W-999	CT RIG	256,576	32,305	224,271
O-204	LAT	179,062	3,550	175,512
O-205	LAT	228,674	3,800	224,874
O-267	LAT	211,787	3,800	207,987
O-270	LAT	225,128	3,800	221,328
O-206	LAT W/ WH	275,996	15,765	260,231
O-233	LAT W/ WH	251,656	20,255	231,401
O-278	LAT W/ WH	248,890	16,475	232,415
S-314	LAT W/ WH	234,801	21,675	213,126
C-423	LU	188,234	23,440	164,794
C-930	LU	157,419	29,475	127,944
W-396	LU	164,716	24,860	139,856
W-675	LU	204,358	26,635	177,723
W-900	LU	118,968	24,150	94,818
W-302	LUT	119,074	17,040	102,034
W-338	LUT	168,515	18,710	149,805
W-901	LUT	181,465	20,250	161,215
C-255	Misc	71,092	6,745	64,347
C-448	Misc	131,647	18,470	113,177
I-101	Misc	70,456	4,260	66,196
Kaster-Heldt #1	Misc	97,365	7,350	90,015
Kuhlman 1-36	Misc	39,228	7,350	31,878
O-177	Misc	117,742	4,260	113,482
Przedwojewski #1	Misc	75,672	8,060	67,612
R-113	Misc	88,619	8,060	80,559
R-128	Misc	136,249	8,770	127,479
R-401	Misc	57,939	6,640	51,299
W-948	Misc	114,983	18,825	96,158
C-453	PA	122,005	2,025	119,980
C-718	PA	170,395	8,800	161,595
C-806	PA	257,528	12,631	244,897
O-106	PA	141,689	4,985	136,704
O-109	PA	144,160	4,985	139,175
O-113	PA	155,167	4,985	150,182
O-114	PA	144,222	4,985	139,237
O-153	PA	189,842	4,985	184,857
O-169	PA	116,149	4,985	111,164
O-176	PA	144,441	4,985	139,456
O-185	PA	116,273	4,985	111,288
O-224	PA	146,357	2,735	143,622
O-225	PA	147,431	4,985	142,446
O-227	PA	142,336	4,985	137,351
O-242	PA	187,032	4,985	182,047
O-243	PA	116,130	4,985	111,145
O-244	PA	148,528	4,985	143,543
W-201	PA	193,045	16,441	176,604
W-319	PA	185,694	16,441	169,253
W-320	PA	174,769	16,441	158,328
W-327	PA	194,483	14,761	179,722
W-385	PA	198,984	16,761	182,223
W-587	PA	178,426	11,921	166,505
W-649	PA	161,798	13,921	147,877
W-691	PA	189,219	9,350	179,869
W-765	PA	238,143	16,441	221,702
W-915	PA	151,259	4,770	146,489
S-309	RPLS	237,019	12,777	224,242
W-544	RPLS	128,448	15,265	113,183
W-272	RPLUS	145,051	6,745	138,306

Row Labels	Average of Total	Average of Internal	Average of External
CT	329,756.42	23,053.10	306,703.32
CT RIG	294,674.41	29,064.80	265,609.61
LAT	211,162.85	3,737.50	207,425.35
LAT W/ WH	252,835.93	18,542.50	234,293.43
LU	166,739.06	25,712.00	141,027.06
LUT	156,351.10	18,666.67	137,684.43
Misc	90,999.02	8,980.91	82,018.11
PA	165,018.54	8,453.48	156,565.05
RPLS	182,733.25	14,021.00	168,712.25
RPLUS	145,051.00	6,745.00	138,306.00
(blank)			
Grand Total	**211,034.67**	**15,919.16**	**195,115.51**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Storage Fields Month End Summary
October 2023 - August 2024 Historical / September 2024 - October 2026 Forecast

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VOLUMES @ 14.65 PSIA DRY

Line No.	(a) MONTH	(b)	(c) GCR VOL - MMCF	(d) GCR $000	(e) GCR $ / MCF	(f) GCC VOL - MMCF	(g) GCC $000	(h) GCC $ / MCF	(i) COMBINED VOL - MMCF	(j) COMBINED $000	(k) COMBINED $ / MCF
1	Oct-23	Booked	167,820	634,482	3.781	11,223	64,119	5.713	179,043	698,601	3.902
2	Nov-23	Booked	152,490	577,204	3.785	12,042	68,861	5.719	164,532	646,066	3.927
3	Dec-23	Booked	137,248	519,505	3.785	11,283	64,524	5.719	148,531	584,028	3.932
4	Jan-24	Booked	110,429	417,990	3.785	9,442	53,994	5.719	119,871	471,984	3.937
5	Feb-24	Booked	94,645	358,243	3.785	6,287	35,953	5.719	100,932	394,196	3.906
6	Mar-24	Booked	78,955	298,834	3.785	4,365	24,962	5.719	83,320	323,796	3.886
7	Apr-24	Booked	89,334	314,095	3.516	-394	-2,251	5.719	88,940	311,845	3.506
8	May-24	Booked	106,353	341,043	3.207	613	3,242	5.292	106,965	344,285	3.219
9	Jun-24	Booked	125,947	378,286	3.004	2,496	13,781	5.521	128,443	392,067	3.052
10	Jul-24	Booked	142,087	415,993	2.928	4,698	26,236	5.585	146,785	442,229	3.013
11	Aug-24	Booked	156,591	439,862	2.809	7,022	39,118	5.571	163,613	478,979	2.928
12	Sep-24	Forecast	166,749	456,669	2.739	9,243	51,403	5.561	175,992	508,072	2.887
13	Oct-24	Forecast	168,349	459,716	2.731	11,260	62,559	5.556	179,609	522,275	2.908
14	13 Month Avg		130,538	431,686	3.307	6,891	38,962	5.654	137,429	470,648	3.425
15	Oct-24	Forecast	168,349	459,716	2.731	11,260	62,559	5.556	179,609	522,275	2.908
16	Nov-24	Forecast	155,463	424,529	2.731	11,961	66,434	5.554	167,424	490,962	2.932
17	Dec-24	Forecast	133,285	363,966	2.731	10,911	60,604	5.554	144,196	424,570	2.944
18	Jan-25	Forecast	107,725	294,167	2.731	8,260	45,877	5.554	115,984	340,044	2.932
19	Feb-25	Forecast	83,376	227,677	2.731	5,106	28,360	5.554	88,482	256,037	2.894
20	Mar-25	Forecast	68,901	188,150	2.731	2,874	15,964	5.554	71,775	204,114	2.844
21	Apr-25	Forecast	79,791	218,785	2.742	-324	-1,408	4.341	79,467	217,376	2.735
22	May-25	Forecast	96,212	264,909	2.753	558	2,421	4.341	96,770	267,330	2.763
23	Jun-25	Forecast	113,329	313,866	2.770	2,394	10,392	4.341	115,723	324,259	2.802
24	Jul-25	Forecast	130,857	365,416	2.792	4,679	20,312	4.341	135,536	385,728	2.846
25	Aug-25	Forecast	148,948	418,741	2.811	7,021	30,480	4.341	155,969	449,222	2.880
26	Sep-25	Forecast	163,152	458,999	2.813	9,211	39,984	4.341	172,362	498,983	2.895
27	Oct-25	Forecast	168,542	474,130	2.813	11,174	48,508	4.341	179,716	522,639	2.908
28	13 Month Avg		124,456	344,081	2.765	6,545	33,114	5.060	131,001.011	377,195.359	2.879
29	Oct-25	Forecast	168,542	474,130	2.813	11,174	48,508	4.341	179,716	522,639	2.908
30	Nov-25	Forecast	152,129	427,959	2.813	11,832	51,362	4.341	163,961	479,321	2.923
31	Dec-25	Forecast	126,149	354,873	2.813	10,792	46,850	4.341	136,941	401,723	2.934
32	Jan-26	Forecast	101,955	286,812	2.813	8,186	35,534	4.341	110,140	322,346	2.927
33	Feb-26	Forecast	80,229	225,696	2.813	5,076	22,035	4.341	85,305	247,731	2.904
34	Mar-26	Forecast	69,003	194,114	2.813	2,878	12,494	4.341	71,881	206,608	2.874
35	Apr-26	Forecast	79,911	227,851	2.851	-323	-1,173	3.635	79,589	226,677	2.848
36	May-26	Forecast	96,324	278,116	2.887	561	2,040	3.635	96,886	280,156	2.892
37	Jun-26	Forecast	113,432	331,336	2.921	2,397	8,713	3.635	115,830	340,050	2.936
38	Jul-26	Forecast	130,949	386,699	2.953	4,682	17,016	3.635	135,631	403,715	2.977
39	Aug-26	Forecast	149,029	444,222	2.981	7,023	25,524	3.635	156,052	469,747	3.010
40	Sep-26	Forecast	163,240	487,591	2.987	9,211	33,479	3.635	172,451	521,070	3.022
41	Oct-26	Forecast	168,648	504,067	2.989	11,174	40,613	3.635	179,822	544,680	3.029
42	13 Month Avg		123,042	355,651	2.890	6,513	26,384	4.051	129,554.050	382,035.501	2.949

EXHIBIT A-79 (HJM-1)
IS CONFIDENTIAL AND
BEING FILED UNDER SEAL
WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Gas Engineering and Supply
($000)

Case No.: U-21806
Exhibit No.: A-80 (KAP-1)
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Witness: KAPascarello
Date: December 2024

Line No.	(a) Description	(b) 2023 Actual	(c) 2024 Projected	(d) 2025 Projected	(e) Projected 12-Mos Ending Oct 31, 2026
1	Project Management and Quality Lean	1,309	1,980	3,002	3,152
2	Gas Asset Management	6,077	7,547	10,501	10,446
3	Gas Engineering Support	4,647	7,027	4,897	3,801
4	Gas Management Services	3,981	4,140	4,130	4,796
5	**Total Gas Engineering and Supply O&M Expenses**	**$ 16,014**	**$ 20,694**	**$ 22,530**	**$ 22,195**

Notes:
*** % breakdown for cost elements is based on 2023 actual
Test Year is based on 2025 and 2026 monthly cashflow

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected O&M Expenses
Gas Engineering and Supply
($000)

Case No.: U-21806
Exhibit No.: A-81 (KAP-2)
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Witness: KAPascarello
Date: December 2024

Line No.		Description	(a) 2023 Actual	(b) 2024 Projected	(c) 2025 Projected	(d) Projected 12-Mos Ending Oct 31, 2026
		Gas Project Management				
1		**Gas Project Management and Lean Office**	**1,309**	**1,980**	**3,002**	**3,152**
	77%	Labor	1,013	1,533	2,324	2,440
	0%	Material	-	-	-	-
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	23%	Non-Labor Other	296	447	678	712
		Gas Asset Management				
2		**Gas Engineering - Distribution**	**632**	**687**	**713**	**730**
	96%	Labor	609	618	622	638
	0%	Material	-	-	-	-
	0%	Contractor	-	44	65	65
	0%	Non-Labor Overheads	-	-	-	-
	4%	Non-Labor Other	23	25	26	27
3		**Gas Engineering - Transmission**	**1,430**	**1,897**	**1,983**	**2,387**
	57%	Labor	808	1,072	1,121	1,350
	21%	Material	294	390	408	491
	7%	Contractor	105	140	146	176
	0%	Non-Labor Overheads	-	-	-	-
	16%	Non-Labor Other	222	295	308	371
4		**Gas Engineering Asset Planning**	**333**	**383**	**383**	**396**
	88%	Labor	294	338	338	350
	0%	Material	-	-	-	-
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	12%	Non-Labor Other	39	45	45	46

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected O&M Expenses
Gas Engineering and Supply
($000)

Case No.: U-21806
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Date: December 2024

Line No.		(a) Description	(b) 2023 Actual	(c) 2024 Projected	(d) 2025 Projected	(e) Projected 12-Mos Ending Oct 31, 2026
5		**System Integrity**	**2,275**	**1,805**	**3,713**	**3,789**
	89%	Labor	2,021	1,604	3,299	3,366
	0%	Material	-	-	-	-
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	11%	Non-Labor Other	254	201	415	423
6		**Gas Compression Engineering**	**777**	**819**	**827**	**1,015**
	84%	Labor	656	692	699	857
	0%	Material	-	-	-	-
	1%	Contractor	4	5	5	6
	0%	Non-Labor Overheads	-	-	-	-
	15%	Non-Labor Other	116	122	124	152
7		**Storage Integrity Management Program ("SIMP")**	**630**	**1,956**	**2,881**	**2,129**
	5%	Labor	29	89	131	97
	0%	Material	1	3	4	3
	79%	Contractor	498	1,546	2,278	1,683
	1%	Non-Labor Overheads	3	10	15	11
	16%	Non-Labor Other	99	308	453	335
		Engineering Support				
8		**Gas Strategy**	**92**	**79**	**87**	**89**
	85%	Labor	78	67	74	75
	0%	Material	-	-	-	-
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	15%	Non-Labor Other	14	12	13	14

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected O&M Expenses
Gas Engineering and Supply
($000)

Case No.: U-21806
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Line No.		(a) Description	(b) 2023 Actual	(c) 2024 Projected	(d) 2025 Projected	(e) Projected 12-Mos Ending Oct 31, 2026
9		**Gas Regulatory & Compliance**	**724**	**1,247**	**1,249**	**1,272**
	82%	Labor	592	1,020	1,022	1,041
	0%	Material	-	-	-	-
	7%	Contractor	50	86	86	88
	0%	Non-Labor Overheads	-	-	-	-
	11%	Non-Labor Other	81	140	141	143
10		**Geospatial Mgmt & Data Quality**	**854**	**690**	**679**	**645**
	64%	Labor	548	443	435	413
	0%	Material	-	-	-	-
	20%	Contractor	168	136	134	127
	0%	Non-Labor Overheads	-	-	-	-
	16%	Non-Labor Other	138	112	110	104
11		**Geospatial Inventory and Modeling Program**	**2,659**	**3,858**	**1,837**	**518**
	2%	Labor	43	63	30	8
	0%	Material	-	-	-	-
	98%	Contractor	2,596	3,767	1,794	506
	0%	Non-Labor Overheads	-	-	-	-
	1%	Non-Labor Other	19	28	13	4
12		**Damage Claims/Prevention**	**221**	**1,037**	**1,000**	**1,231**
	95%	Labor	243	985	950	1,169
	0%	Material	-	-	-	-
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	5%	Non-Labor Other	(21)	52	50	62

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected O&M Expenses
Gas Engineering and Supply
($000)

Case No.: U-21806
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Line No.		(a) Description	(b) 2023 Actual	(c) 2024 Projected	(d) 2025 Projected	(e) Projected 12-Mos Ending Oct 31, 2026
13		**Enterprise Corrective Action Program**	**54**	**65**	**-**	**-**
	98%	Labor	52	64	-	-
	0%	Material	-	-	-	-
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	2%	Non-Labor Other	1	1	-	-
14		**Engineering Management**	**43**	**51**	**45**	**46**
	98%	Labor	41	50	44	45
	0%	Material	-	-	-	-
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	2%	Non-Labor Other	2	1	1	1
		Gas Management Services				
15		**Gas Management Services**	**3,981**	**4,140**	**4,130**	**4,796**
	97%	Labor	3,878	4,033	4,022	4,422
	0%	Material	-	-	-	-
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	3%	Non-Labor Other	103	107	107	374
16		**Total Gas Engineering and Supply O&M Expenses**	**$ 16,014**	**$ 20,694**	**$ 22,530**	**$ 22,195**
		Labor	10,906	12,670	15,111	16,271
		Material	295	393	412	494
		Contractor	3,423	5,724	4,508	2,651
		Non-Labor Overheads	3	10	15	11
		Non-Labor Other	1,387	1,897	2,483	2,767

Notes:
*** % breakdown for cost elements is based on 2023 actual
Test Year is based on 2025 and 2026 monthly cashflow

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Gas Engineering and Supply
($000)

Case No.: U-21806
Exhibit No.: A-81 (KAP-2)
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Date: December 2024

Line No.	(a) Description	(b) Actual 12 Mos Ending 31-Dec-23	(c) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2023	(d) Merit & Inflation 12 Mos Ending Dec 31, 2024	(e) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	(f) Merit & Inflation 12 Mos Ending Dec 31, 2025	(g) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	(h) Merit & Inflation 10 Mos Ending Oct 31, 2026	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending Oct 31, 2026
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	**Gas Project Management and Quality Lean Office**	**1,309**	**1,309**	**-**	**1,309**	**-**	**1,309**	**-**	**1,843**	**3,152**
	Labor	1,013	1,013	-	1,013	-	1,013	-	1,427	2,440
	Material	-	-	-	-	-	-	-	-	-
	Contractor	-	-	-	-	-	-	-	-	-
	Non-Labor Overheads	-	-	-	-	-	-	-	-	-
	Non-Labor Other	296	296	-	296	-	296	-	417	712
2	**Gas Engineering - Distribution**	**632**	**632**	**-**	**632**	**-**	**632**	**-**	**98**	**730**
	Labor	609	609	-	609	-	609	-	29	638
	Material	-	-	-	-	-	-	-	-	-
	Contractor	-	-	-	-	-	-	-	65	65
	Non-Labor Overheads	-	-	-	-	-	-	-	-	-
	Non-Labor Other	23	23	-	23	-	23	-	4	27
3	**Gas Engineering - Transmission**	**1,430**	**1,430**	**-**	**1,430**	**-**	**1,430**	**-**	**957**	**2,387**
	Labor	808	808	-	808	-	808	-	541	1,350
	Material	294	294	-	294	-	294	-	197	491
	Contractor	105	105	-	105	-	105	-	71	176
	Non-Labor Overheads	-	-	-	-	-	-	-	-	-
	Non-Labor Other	222	222	-	222	-	222	-	149	371
4	**Gas Engineering Asset Planning**	**333**	**333**	**-**	**333**	**-**	**333**	**-**	**63**	**396**
	Labor	294	294	-	294	-	294	-	55	350
	Material	-	-	-	-	-	-	-	-	-
	Contractor	-	-	-	-	-	-	-	-	-
	Non-Labor Overheads	-	-	-	-	-	-	-	-	-
	Non-Labor Other	39	39	-	39	-	39	-	7	46
5	**System Integrity**	**2,275**	**2,275**	**-**	**2,275**	**-**	**2,275**	**-**	**1,513**	**3,789**
	Labor	2,021	2,021	-	2,021	-	2,021	-	1,344	3,366
	Material	-	-	-	-	-	-	-	-	-
	Contractor	-	-	-	-	-	-	-	-	-
	Non-Labor Overheads	-	-	-	-	-	-	-	-	-
	Non-Labor Other	254	254	-	254	-	254	-	169	423
6	**Gas Compression Engineering**	**777**	**777**	**-**	**777**	**-**	**777**	**-**	**238**	**1,015**
	Labor	656	656	-	656	-	656	-	201	857
	Material	-	-	-	-	-	-	-	-	-
	Contractor	4	4	-	4	-	4	-	1	6
	Non-Labor Overheads	-	-	-	-	-	-	-	-	-
	Non-Labor Other	116	116	-	116	-	116	-	36	152

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Gas Engineering and Supply
($000)

Case No.: U-21806
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Line No.	(a) Description	(b) Actual 12 Mos Ending 31-Dec-23	(c) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2023	(d) Merit & Inflation 12 Mos Ending Dec 31, 2024	(e) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	(f) Merit & Inflation 12 Mos Ending Dec 31, 2025	(g) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	(h) Merit & Inflation 10 Mos Ending Oct 31, 2026	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending Oct 31, 2026
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
7	**Storage Integrity Management Program ("SIMP")**	**630**	**630**	**-**	**630**	**-**	**630**	**-**	**1,499**	**2,129**
	Labor	29	29	-	29	-	29	-	68	97
	Material	1	1	-	1	-	1	-	2	3
	Contractor	498	498	-	498	-	498	-	1,185	1,683
	Non-Labor Overheads	3	3	-	3	-	3	-	8	11
	Non-Labor Other	99	99	-	99	-	99	-	236	335
8	**Gas Strategy**	**92**	**92**	**-**	**92**	**-**	**92**	**-**	**(3)**	**89**
	Labor	78	78	-	78	-	78	-	(3)	75
	Material	-	-	-	-	-	-	-	-	-
	Contractor	-	-	-	-	-	-	-	-	-
	Non-Labor Overheads	-	-	-	-	-	-	-	-	-
	Non-Labor Other	14	14	-	14	-	14	-	(1)	14
9	**Gas Regulatory & Compliance**	**724**	**724**	**-**	**723**	**-**	**723**	**-**	**548**	**1,272**
	Labor	592	592	-	592	-	592	-	448	1,041
	Material	-	-	-	-	-	-	-	-	-
	Contractor	50	50	-	50	-	50	-	38	88
	Non-Labor Overheads	-	-	-	-	-	-	-	-	-
	Non-Labor Other	81	81	-	81	-	81	-	62	143
10	**Geospatial Mgmt & Data Quality**	**854**	**854**	**-**	**854**	**-**	**854**	**-**	**(209)**	**645**
	Labor	548	548	-	548	-	548	-	(134)	413
	Material	-	-	-	-	-	-	-	-	-
	Contractor	168	168	-	168	-	168	-	(41)	127
	Non-Labor Overheads	-	-	-	-	-	-	-	-	-
	Non-Labor Other	138	138	-	138	-	138	-	(34)	104
11	**Geospatial Inventory and Modeling Program**	**2,659**	**2,659**	**-**	**2,659**	**-**	**2,659**	**-**	**(2,140)**	**518**
	Labor	43	43	-	43	-	43	-	(35)	8
	Material	-	-	-	-	-	-	-	-	-
	Contractor	2,596	2,596	-	2,596	-	2,596	-	(2,090)	506
	Non-Labor Overheads	-	-	-	-	-	-	-	-	-
	Non-Labor Other	19	19	-	19	-	19	-	(15)	4
12	**Damage Claims/Prevention**	**221**	**221**	**-**	**221**	**-**	**221**	**-**	**1,010**	**1,231**
	Labor	243	243	-	243	-	243	-	927	1,169
	Material	-	-	-	-	-	-	-	-	-
	Contractor	-	-	-	-	-	-	-	-	-
	Non-Labor Overheads	-	-	-	-	-	-	-	-	-
	Non-Labor Other	(21)	(21)	-	(21)	-	(21)	-	83	62

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Gas Engineering and Supply
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
13	**Enterprise Corrective Action Program**	**54**	**54**	**-**	**41**	**-**	**41**	**-**	**(54)**	**-**
	Labor	52	40	-	40	-	40	-	(52)	-
	Material	-	-	-	-	-	-	-	-	-
	Contractor	-	-	-	-	-	-	-	-	-
	Non-Labor Overheads	-	-	-	-	-	-	-	-	-
	Non-Labor Other	1	1	-	1	-	1	-	(1)	-
14	**Engineering Management**	**43**	**43**	**-**	**42**	**-**	**42**	**-**	**3**	**46**
	Labor	41	40	-	40	-	40	-	4	45
	Material	-	-	-	-	-	-	-	-	-
	Contractor	-	-	-	-	-	-	-	-	-
	Non-Labor Overheads	-	-	-	-	-	-	-	-	-
	Non-Labor Other	2	2	-	2	-	2	-	(1)	1
15	**Gas Management Services**	**3,981**	**3,981**	**-**	**3,981**	**-**	**3,981**	**-**	**815**	**4,796**
	Labor	3,878	3,878	-	3,878	-	3,878	-	544	4,422
	Material	-	-	-	-	-	-	-	-	-
	Contractor	-	-	-	-	-	-	-	-	-
	Non-Labor Overheads	-	-	-	-	-	-	-	-	-
	Non-Labor Other	103	103	-	103	-	103	-	271	374
16	**Total Gas Engineering and Supply O&M Expenses**	**$ 16,014**	**$ 16,001**	**$ -**	**$ 16,001**	**$ -**	**$ 16,001**	**$ -**	**$ 6,180**	**$ 22,195**
	Labor	10,906	10,893	-	10,893	-	10,893	-	5,364	16,271
	Material	295	295	-	295	-	295	-	199	494
	Contractor	3,423	3,423	-	3,423	-	3,423	-	(772)	2,651
	Non-Labor Overheads	3	3	-	3	-	3	-	8	11
	Non-Labor Other	1,387	1,387	-	1,387	-	1,387	-	1,381	2,768

Notes

Base Labor is all labor cost elements less OM&C & Indirect Labor

		12-Mo Ending 2024	12-Mo Ending 2025	10-Mo Ending 2026
17				
	Annual inflation rates	0.0%	0.0%	0.0%
	Number of months in the period	12	12	10
	Pro-rated inflation rate	0.0%	0.0%	0.0%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Historical Expenses
Gas Engineering and Supply
($000)

Case No.: U-21806
Exhibit No.: A-81 (KAP-2)
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Line No.	(a) Description	(b) 2019 Actual	(c) 2020 Actual	(d) 2021 Actual	(e) 2022 Actual	(f) 2023 Actual
	Gas Project Management					
1	**Gas Project Management and Quality Lean Office**	**1,311**	**699**	**1,959**	**1,929**	**1,309**
	Labor	919	1,091	1,277	1,543	1,013
	Material	-	-	-	-	-
	Contractor	2	-	-	-	-
	Non-Labor Overheads	-	-	-	-	-
	Non-Labor Other	390	(392)	682	386	296
	Gas Asset Management					
2	**Gas Engineering - Distribution**	**1,266**	**1,180**	**1,001**	**671**	**632**
	Labor	746	762	633	650	609
	Material	417	361	368	-	-
	Contractor	-		20	-	-
	Non-Labor Overheads	-		12	0	-
	Non-Labor Other	103	57	(32)	20	23
3	**Gas Engineering - Transmission**	**2,360**	**562**	**657**	**1,393**	**1,430**
	Labor	502	522	559	660	808
	Material	-		-	569	294
	Contractor	2		1	3	105
	Non-Labor Overheads	-		-	-	-
	Non-Labor Other	1,856	40	98	160	222

MICHIGAN PUBLIC SERVICE COMMISSION
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Summary of O&M Historical Expenses
Gas Engineering and Supply
($000)

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Line No.	(a) Description	(b) 2019 Actual	(c) 2020 Actual	(d) 2021 Actual	(e) 2022 Actual	(f) 2023 Actual
4	**Gas Engineering Asset Planning**	**216**	**183**	**231**	**303**	**333**
	Labor	188	169	211	281	294
	Material	-		0	-	-
	Contractor	-		-	-	-
	Non-Labor Overheads	-		-	-	-
	Non-Labor Other	28	14	20	23	39
5	**System Integrity**	**1,631**	**1,530**	**1,887**	**2,071**	**2,275**
	Labor	1,438	1,410	1,699	1,849	2,021
	Material	-		0	-	-
	Contractor	-	0	-	-	-
	Non-Labor Overheads	-		-	-	-
	Non-Labor Other	193	119	188	222	254
6	**Gas Compression Engineering**	**783**	**842**	**823**	**846**	**777**
	Labor	735	710	664	721	656
	Material	-	-	-	-	-
	Contractor	-	-	-	1	4
	Non-Labor Overheads	-	-	-	-	-
	Non-Labor Other	48	132	159	124	116
7	**Storage Integrity Management Program ("SIMP")**	**-**	**-**	**-**	**629**	**630**
	Labor	-	-	-	8	29
	Material	-	-	-	-	1
	Contractor	-	-	-	571	498
	Non-Labor Overheads	-	-	-	2	3
	Non-Labor Other	-	-	-	47	99

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Line No.	(a) Description	(b) 2019 Actual	(c) 2020 Actual	(d) 2021 Actual	(e) 2022 Actual	(f) 2023 Actual
	Engineering Support					
8	**Gas Strategy**	**70**	**473**	**272**	**255**	**92**
	Labor	68	212	206	214	78
	Material	-		-	-	-
	Contractor	-	250	23	-	-
	Non-Labor Overheads	-		-	-	-
	Non-Labor Other	2	11	43	40	14
9	**Gas Regulatory & Compliance**	**913**	**393**	**430**	**565**	**724**
	Labor	768	378	402	436	592
	Material	6		-	-	-
	Contractor	-		-	110	50
	Non-Labor Overheads	-		-	-	-
	Non-Labor Other	138	15	28	19	81
10	**Geospatial Mgmt & Data Quality**	**544**	**554**	**690**	**763**	**854**
	Labor	403	460	552	592	548
	Material	-	-	-	-	-
	Contractor	-	-	-	-	168
	Non-Labor Overheads	-	-	-	-	-
	Non-Labor Other	141	94	138	171	138

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Line No.	(a) Description	(b) 2019 Actual	(c) 2020 Actual	(d) 2021 Actual	(e) 2022 Actual	(f) 2023 Actual
11	**Geospatial Inventory and Modeling Program**	**-**	**-**	**-**	**591**	**2,659**
	Labor	-	-	-	-	43
	Material	-	-	-	-	-
	Contractor	-	-	-	-	2,596
	Non-Labor Overheads	-	-	-	-	-
	Non-Labor Other	-	-	-	591	19
12	**Damage Claims/Prevention**	**-**	**-**	**-**	**-**	**221**
	Labor	-	-	-	-	243
	Material	-	-	-	-	-
	Contractor	-	-	-	-	-
	Non-Labor Overheads	-	-	-	-	-
	Non-Labor Other	-	-	-	-	(21)
13	**Enterprise Corrective Action Program**	**-**	**-**	**-**	**-**	**54**
	Labor	-	-	-	-	52
	Material	-	-	-	-	-
	Contractor	-	-	-	-	-
	Non-Labor Overheads	-	-	-	-	-
	Non-Labor Other	-	-	-	-	1

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($000)

Case No.: U-21806
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Line No.	(a) Description	(b) 2019 Actual	(c) 2020 Actual	(d) 2021 Actual	(e) 2022 Actual	(f) 2023 Actual
14	**Customer Energy Management**	**601**	**488**	**584**	**-**	**-**
	Labor	455	452	537	-	-
	Material	-		0	-	-
	Contractor	-		-	-	-
	Non-Labor Overheads	-		-	-	-
	Non-Labor Other	146	35	47	-	-
15	**Engineering Management**	**-**	**-**	**-**	**-**	**43**
	Labor					41
	Material					-
	Contractor					-
	Non-Labor Overheads					-
	Non-Labor Other					2
	Gas Management Services					
16	**Gas Management Services**	**3,906**	**3,677**	**3,874**	**3,941**	**3,981**
	Labor	3,828	3,602	3,647	3,842	3,878
	Material	-		-	-	-
	Contractor	-		-	-	-
	Non-Labor Overheads	-		-	-	-
	Non-Labor Other	78	75	227	100	103
17	**Total Gas Engineering and Supply O&M Expenses**	**$ 13,600**	**$ 10,580**	**$ 12,408**	**$ 13,957**	**$ 16,014**
	Labor	10,050	9,769	10,387	10,797	10,906
	Material	423	361	369	569	295
	Contractor	4	250	44	685	3,423
	Non-Labor Overheads	-	-	12	2	3
	Non-Labor Other	3,124	200	1,597	1,903	1,387

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Capital Expenditures
Material Condition Program
($000)

Case No.: U-21806
Exhibit No.: A-82 (KAP-4)
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Witness: KAPascarello
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026
1	**EIRP - Distribution**	**181,927**	**195,587**	**207,322**	**402,909**	**251,372**
22%	Labor	38,053	42,114	44,641	86,755	54,126
24%	Capitalized Engineering/Supv	44,266	47,088	49,913	97,000	60,518
5%	Materials	8,319	9,922	10,517	20,439	12,752
21%	Contractor	38,437	41,657	44,156	85,814	53,538
11%	Non-Labor Overhead	20,859	21,581	22,875	44,456	27,736
17%	Non-Labor Other	31,993	33,226	35,220	68,446	42,703
2	**Material Condition Non Modeled**	**38,516**	**38,256**	**36,358**	**74,614**	**56,206**
18%	Labor	6,552	6,968	6,622	13,590	10,237
24%	Capitalized Engineering/Supv	9,517	9,366	8,901	18,268	13,761
7%	Materials	2,677	2,725	2,590	5,315	4,004
25%	Contractor	10,070	9,629	9,151	18,780	14,147
5%	Non-Labor Overhead	1,938	1,871	1,778	3,649	2,749
20%	Non-Labor Other	7,761	7,698	7,316	15,013	11,309
3	**Material Condition Renewals**	**31,816**	**31,872**	**30,666**	**62,538**	**33,182**
38%	Labor	11,783	11,977	11,524	23,501	12,469
22%	Capitalized Engineering/Supv	6,971	7,040	6,773	13,813	7,329
6%	Materials	1,324	1,817	1,748	3,566	1,892
6%	Contractor	2,347	1,982	1,908	3,890	2,064
7%	Non-Labor Overhead	2,462	2,329	2,241	4,570	2,425
21%	Non-Labor Other	6,929	6,726	6,472	13,199	7,003
4	**Vintage Service Replacements**	**11,354**	**18,666**	**25,885**	**44,551**	**42,513**
24%	Labor	2,989	4,550	6,309	10,859	10,362
24%	Capitalized Engineering/Supv	2,744	4,473	6,203	10,676	10,188
1%	Materials	135	265	368	633	604
12%	Contractor	739	2,293	3,180	5,473	5,222
7%	Non-Labor Overhead	929	1,228	1,703	2,930	2,796
31%	Non-Labor Other	3,820	5,857	8,123	13,980	13,341
5	**Commercial and Industrial Meters**	**2,684**	**1,300**	**1,634**	**2,934**	**2,391**
15%	Labor	344	189	238	428	348
25%	Capitalized Engineering/Supv	677	325	409	734	599
14%	Materials	367	188	237	425	346
26%	Contractor	771	342	430	772	629
2%	Non-Labor Overhead	49	26	33	59	48
18%	Non-Labor Other	476	228	287	515	420
6	**Total Capital**	**266,297**	**285,681**	**301,865**	**587,546**	**385,665**
	Labor	59,721	65,798	69,334	135,132	87,543
	Capitalized Engineering/Supv	64,175	68,292	72,200	140,491	92,394
	Materials	12,822	14,918	15,460	30,377	19,598
	Contractor	52,364	55,903	58,825	114,728	75,601
	Non-Labor Overhead	26,236	27,035	28,630	55,665	35,754
	Non-Labor Other	50,979	53,736	57,417	111,153	74,776

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
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Material Condition Program
($000)

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	(a)	(b)	(c)	(d)	(e)	(f)
			Projected			
		10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026	
7	**EIRP - Distribution**	**172,399**	**230,510**	**251,372**	**654,281**	
22%	Labor	37,121	49,634	54,126	140,880	
24%	Capitalized Engineering/Supv	41,505	55,495	60,518	157,518	
5%	Materials	8,746	11,693	12,752	33,191	
21%	Contractor	36,718	49,095	53,538	139,352	
11%	Non-Labor Overhead	19,022	25,434	27,736	72,192	
17%	Non-Labor Other	29,287	39,159	42,703	111,148	
8	**Material Condition Non Modeled**	**31,986**	**42,628**	**56,206**	**130,821**	
18%	Labor	5,826	7,764	10,237	23,827	
24%	Capitalized Engineering/Supv	7,831	10,436	13,761	32,028	
7%	Materials	2,278	3,036	4,004	9,318	
25%	Contractor	8,051	10,729	14,147	32,926	
5%	Non-Labor Overhead	1,564	2,085	2,749	6,398	
20%	Non-Labor Other	6,436	8,577	11,309	26,323	
9	**Material Condition Renewals**	**30,786**	**31,752**	**33,182**	**95,720**	
38%	Labor	11,569	11,932	12,469	35,971	
22%	Capitalized Engineering/Supv	6,800	7,013	7,329	21,142	
6%	Materials	1,755	1,810	1,892	5,458	
6%	Contractor	1,915	1,975	2,064	5,954	
7%	Non-Labor Overhead	2,250	2,320	2,425	6,994	
21%	Non-Labor Other	6,497	6,701	7,003	20,202	
10	**Vintage Service Replacements**	**18,435**	**26,116**	**42,513**	**87,064**	
24%	Labor	4,493	6,366	10,362	21,221	
24%	Capitalized Engineering/Supv	4,418	6,259	10,188	20,864	
1%	Materials	262	371	604	1,236	
12%	Contractor	2,264	3,208	5,222	10,695	
7%	Non-Labor Overhead	1,213	1,718	2,796	5,727	
31%	Non-Labor Other	5,785	8,195	13,341	27,321	
11	**Commercial and Industrial Meters**	**772**	**2,161**	**2,391**	**5,325**	
15%	Labor	113	315	348	776	
25%	Capitalized Engineering/Supv	193	541	599	1,333	
14%	Materials	112	313	346	772	
26%	Contractor	203	569	629	1,402	
2%	Non-Labor Overhead	16	44	48	108	
18%	Non-Labor Other	136	379	420	935	
12	**Total Capital**	**254,378**	**333,168**	**385,665**	**973,211**	
	Labor	59,122	76,010	87,543	222,675	
	Capitalized Engineering/Supv	60,747	79,744	92,394	232,885	
	Materials	13,153	17,224	19,598	49,975	
	Contractor	49,152	65,576	75,601	190,329	
	Non-Labor Overhead	24,064	31,600	35,754	91,419	
	Non-Labor Other	48,141	63,012	74,776	185,928	

Unless noted otherwise, capital “other” costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).

This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month average (Jan 2023 - Jun 2024) actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop projected test year costs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Material Condition Program
($000)

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Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Year 12 Mos Ended 12/31/2024	(d) Projected Bridge Year 10 Mos Ending 10/31/2025	(e) Projected Bridge Year 22 Mos Ending 10/31/2025 [Col. (c) + (d)]	(f) Projected Test Year 12 Mos Ending 10/31/2026
	Projects Over $5 Million					
1	EIRP - Distribution					
2	OWS2 - Ph 1,2 Corruna	-	-	5,442	5,442	1,128
3	ALM2 - Ph 4, 7 and 6 St. Louis	-	-	5,689	5,689	1,179
4	SAG6 - TOD Line 1087g	-	-	15,066	15,066	3,122
5	SAG8 Frankenmuth(Junction Rd)	-	-	5,935	5,935	1,230
6	LIV4 - Ph 1,2	-	-	14,471	14,471	2,999
7	ROK4 - Ph 2,3,5,6	-	1,050	5,809	6,859	1,204
8	ROK13 - Ph 1	-	-	5,070	5,070	1,051
9	KAL2 - Ph 1,2,4,5,10 HP	-	-	12,167	12,167	2,522
10	LAN4 - Ph 4,5,6,7,8	-	6,282	12,605	18,887	2,612
11	MAC12 - Ph 1,2,3,4,5,6,7,8	-	3,944	24,633	28,577	5,105
12	FLT5 - Ph 1,2,3	-	-	8,039	8,039	1,666
13	MAC14 - Ph 2	-	-	4,699	4,699	974
14	ALM5 - PH1 Line 1070g	-	-	6,620	6,620	1,372
15	FLT11 - Ph 1,2,3,4,5,6	-	-			17,749
16	OWS3 - Ph 1,2	-	-			6,488
17	SAG4 - Ph 1,2,3	-	-			17,749
18	BCY2 - Ph 2	-	-			7,344
19	ALM2 - Ph 1,7,8	-	-			9,303
20	ALM5 - Ph 2 Line 1070g	-	-			4,713
21	MAC11 - Ph 2,3,5,6,7,11	-	-			14,934
22	ROK12 - Ph 1,2	-	-			4,774
23	ROK10 - Ph 1,2,3,4,5,6	-	-			15,423
24	ROK7 - Ph 4,5,6,7,8	-	-			23,625
25	KAL3 - Ph 8,9,10	-	-			6,732
26	KAL11 - Ph 1,2,3 Bangor	-	-			9,303
27	LAN14 - Mt Hope & Chippewa	-	-			5,386
28	KAL7 - Michigan Ave Galesburg	-	-			6,732
29	KAL8 - VW Ave (east of Schoolcraft	-	-			6,284
30	LAN13 - Thornapple Lake Rd at M6(	-	-			5,386
31	LAN10 Ph1 & Ph2 TOD Line 1022					4,937
32	Material Condition Non Modeled					
33	Line 1010 Replacement	841	7,200	10,900	18,100	9,300
34	Material Condition Renewals					
35	None identified	-	-	-	-	-
36	Vintage Service Replacements					
37	None identified	-	-	-	-	-
38	Commercial and Industrial Meters					
39	None identified	-	-	-	-	-
	Projects Under $5 Million					
40	EIRP - Distribution	181,927	184,311	81,076	265,388	58,346
41	Material Condition Non Modeled	37,675	31,056	25,458	56,514	46,906
42	Material Condition Renewals	31,816	31,872	30,666	62,538	33,182
43	Vintage Service Replacements	11,354	18,666	25,885	44,551	42,513
44	Commercial and Industrial Meters	2,684	1,300	1,634	2,934	2,391
45	**Total Capital**	266,297	285,681	301,865	587,546	385,665

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas & Common Capital Expenditures
Gas Operations Other Program
($000)

Case No.: U-21806
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	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026
1	**Routine Computer & Equipment**	**300**	**50**	**5**	**55**	**50**
0%	Labor	0	0	0	0	0
0%	Capitalized Engineering/Supv	0	0	0	0	0
0%	Materials	(2)	(0)	(0)	(0)	(0)
40%	Contractor	119	20	2	22	20
0%	Non-Labor Overhead	0	0	0	0	0
61%	Non-Labor Other	183	30	3	33	30
2	**Tools**	**5,613**	**4,510**	**2,472**	**6,982**	**4,510**
0%	Labor	0	0	0	0	0
0%	Capitalized Engineering/Supv	0	0	0	0	0
100%	Materials	5,613	4,510	2,472	6,982	4,510
0%	Contractor	0	0	0	0	0
0%	Non-Labor Overhead	0	0	0	0	0
0%	Non-Labor Other	0	0	0	0	0
3	**Land & ROW**	**1,622**	**831**	**701**	**1,532**	**849**
3%	Labor	249	29	24	53	29
0%	Capitalized Engineering/Supv	0	0	0	0	0
0%	Materials	4	2	2	4	2
8%	Contractor	(638)	64	54	118	65
0%	Non-Labor Overhead	0	0	0	0	0
89%	Non-Labor Other	2,006	736	621	1,357	752
4	**Compliance & Controls Projects**	**214**	**4,875**	**447**	**5,322**	**4,168**
16%	Labor	44	797	73	870	681
0%	Capitalized Engineering/Supv	0	0	0	0	0
0%	Materials	0	0	0	0	0
53%	Contractor	(242)	2,572	236	2,807	2,199
0%	Non-Labor Overhead	0	0	0	0	0
31%	Non-Labor Other	412	1,506	138	1,644	1,288
5	**Geospatial Inventory and Modeling Program**	**0**	**5,828**	**8,319**	**14,147**	**7,513**
8%	Labor	0	461	658	1,119	594
0%	Capitalized Engineering/Supv	0	0	0	0	0
0%	Materials	0	0	0	0	0
73%	Contractor	0	4,247	6,063	10,310	5,475
0%	Non-Labor Overhead	0	0	0	0	0
19%	Non-Labor Other	0	1,120	1,599	2,718	1,444
6	**Total Capital**	**7,750**	**16,094**	**11,943**	**28,037**	**17,090**
	Labor	293	1,287	755	2,042	1,305
	Capitalized Engineering/Supv	0	0	0	0	0
	Materials	5,615	4,512	2,474	6,986	4,512
	Contractor	(761)	6,903	6,354	13,257	7,759
	Non-Labor Overhead	0	0	0	0	0
	Non-Labor Other	2,602	3,392	2,360	5,753	3,514

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas & Common Capital Expenditures
Gas Operations Other Program
($000)

Case No.: U-21806
Exhibit No.: A-83 (KAP-5)
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Witness: KAPascarello
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
			Projected			
		10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026	
7	**Routine Computer & Equipment**	**1**	**54**	**50**	**105**	
0%	Labor	0	0	0	0	
0%	Capitalized Engineering/Supv	0	0	0	0	
0%	Materials	(0)	(0)	(0)	(0)	
40%	Contractor	0	21	20	41	
0%	Non-Labor Overhead	0	0	0	0	
61%	Non-Labor Other	1	33	30	64	
8	**Tools**	**3,305**	**3,677**	**4,510**	**11,492**	
0%	Labor	0	0	0	0	
0%	Capitalized Engineering/Supv	0	0	0	0	
100%	Materials	3,305	3,677	4,510	11,492	
0%	Contractor	0	0	0	0	
0%	Non-Labor Overhead	0	0	0	0	
0%	Non-Labor Other	0	0	0	0	
9	**Land & ROW**	**927**	**605**	**849**	**2,381**	
3%	Labor	32	21	29	82	
0%	Capitalized Engineering/Supv	0	0	0	0	
0%	Materials	3	2	2	7	
8%	Contractor	72	47	65	184	
0%	Non-Labor Overhead	0	0	0	0	
89%	Non-Labor Other	821	536	752	2,108	
10	**Compliance & Controls Projects**	**1,590**	**3,732**	**4,168**	**9,490**	
16%	Labor	260	610	681	1,552	
0%	Capitalized Engineering/Supv	0	0	0	0	
0%	Materials	0	0	0	0	
53%	Contractor	839	1,969	2,199	5,006	
0%	Non-Labor Overhead	0	0	0	0	
31%	Non-Labor Other	491	1,153	1,288	2,932	
11	**Geospatial Inventory and Modeling Program**	**0**	**14,147**	**7,513**	**21,660**	
8%	Labor	0	1,119	594	1,713	
0%	Capitalized Engineering/Supv	0	0	0	0	
0%	Materials	0	0	0	0	
73%	Contractor	0	10,310	5,475	15,785	
0%	Non-Labor Overhead	0	0	0	0	
19%	Non-Labor Other	0	2,718	1,444	4,162	
12	**Total Capital**	**5,823**	**22,214**	**17,090**	**45,127**	
	Labor	292	1,750	1,305	3,347	
	Capitalized Engineering/Supv	0	0	0	0	
	Materials	3,308	3,678	4,512	11,498	
	Contractor	911	12,346	7,759	21,016	
	Non-Labor Overhead	0	0	0	0	
	Non-Labor Other	1,313	4,440	3,514	9,266	

Unless noted otherwise, capital "other" costs include expenses such as AFUDC, fleet transportation, pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, and business expenses (e.g., travel, meals, etc.).

This exhibit demonstrates the projected break down for each program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month average (Jan 2023 - Jun 2024) actual percentage of the breakdown of these components in these programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes. Cost confidence levels were not used to develop projected test year costs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas & Common Capital Expenditures
Gas Operations Other Program
($000)

Case No.: U-21806
Exhibit No.: A-83 (KAP-5)
Page: 3 of 3
Witness: KAPascarello
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Year			Projected Test Year
Line No	Description	12 Mos Ended 12/31/2023	12 Mos Ending 12/31/2024	10 Mos Ending 10/31/2025	22 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026
					[Col. (c) + (d)]	
	Projects Over $5 Million					
1	Routine Computer & Equipment					
2	None identified	-	-	-	-	-
3	Tools					
4	None identified	-	-	-	-	-
5	Land & ROW					
6	None identified	-	-	-	-	-
7	Compliance & Controls Projects					
8	None identified	-	-	-	-	-
9	Geospatial Inventory and Modeling Program					
10	Utility Network	-	5,828	8,319	14,147	7,513
	Projects Under $5 Million					
11	Routine Computer & Equipment	300	50	5	55	50
12	Tools	5,613	4,510	2,472	6,982	4,510
13	Land & ROW	1,622	831	701	1,532	849
14	Compliance & Controls Projects	214	4,875	447	5,322	4,168
15	Geospatial Inventory and Modeling Pro	-	-	-	-	-
16	**Total Capital**	7,750	16,094	11,943	28,037	17,090

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
Exhibit No.: A-84 (KAP-6)
Page: 1 of 3
Witness: KAPascarello
Date: December 2024

Line #		Company Regions			
		Southwest (SW)	Northeast (NE)	Southeast (SE)	Total
	Company Costs:				
1	**2023 Actual Total** [(1)]				
2	Total Services Renewal, Retired Tie-overs	1,358	3,322	3,969	8,649
3	**Miles Main Installed**	**17.35**	**55.12**	**36.47**	**108.9**
4	Total Service/Miles	78	60	109	79
5	Project Cost ($M)	$40.7	$79.8	$56.1	$176.6
6	Carry-Over & Future Year ($M)	$1.0	$2.4	$1.9	$5.4
7	**Total Cost ($(Million)**	**$41.7**	**$82.2**	**$58.0**	**$181.9**
8	**Cost per Mile**	**$ 2,402,397**	**$ 1,492,154**	**$ 1,590,322**	**$ 1,669,978**
9	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**)				$ 3,550,319
10	**2023 Total EIRP Program and Facilities capital expenditures**				**$ 185,476,950**
11					
12	**2024 Projected Total**				
13	Total Services Renewal, Retired Tie-overs	2,150	4,426	5,538	12,114
14	**Miles Main Installed**	**43.64**	**42.44**	**48.56**	**134.6**
15	Total Service/Miles	49	104	114	90
16	Project Cost ($M)	$61.8	$58.7	$70.1	$190.6
17	Carry-Over & Future Year ($M)	$1.1	$2.3	$1.7	$5.0
18	**Total Cost ($(Million)**	**$62.8**	**$60.9**	**$71.8**	**$195.6**
19	**Cost per Mile**	**$ 1,440,092**	**$ 1,435,338**	**$ 1,479,113**	**$ 1,452,667**
20	**EIRP Facilities (expenditures shown in Facilities Exhibit A-70 (QAG-3))**				**$ 6,088,574**
21	**2023 Total EIRP Program and Facilities capital expenditures**				**$ 201,675,656**
22					
23	**2025 Projected Total**				
24	Total Services Renewal, Retired Tie-overs	2,588	2,689	7,251	12,528
25	**Miles Main Installed**	**30.32**	**52.19**	**59.47**	**142.0**
26	Total Service/Miles	85	52	122	88
27	Project Cost ($M)	$50.8	$110.8	$83.6	$245.3
28	Carry-Over & Future Year ($M)	$1.0	$2.1	$1.9	$5.0
29	**Total Cost ($(Million)**	**$51.8**	**$112.9**	**$85.5**	**$250.3**
30	**Cost per Mile**	**$ 1,709,238**	**$ 2,163,624**	**$ 1,438,423**	**$ 1,762,831**
31					
32	**2026 Projected Total**				
33	Total Services Renewal, Retired Tie-overs	1,320	4,126	6,457	11,903
34	**Miles Main Installed**	**30.89**	**57.47**	**61.96**	**150.3**
35	Total Service/Miles	43	72	104	79
36	Project Cost ($M)	$68.5	$88.0	$90.1	$246.6
37	Carry-Over & Future Year ($M)	$1.0	$2.1	$1.9	$5.0
38	**Total Cost ($(Million)**	**$69.5**	**$90.1**	**$92.0**	**$251.6**
39	**Cost per Mile**	**$ 2,249,156**	**$ 1,568,140**	**$ 1,484,958**	**$ 1,673,806**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
Exhibit No.: A-84 (KAP-6)
Page: 2 of 3
Witness: KAPascarello
Date: December 2024

		Company Regions			
		Southwest (SW)	Northeast (NE)	Southeast (SE)	
40	**2023 actual capital expeditures [1]:**				
41	2023 Actual Cost Per Mile - Plastic	$ 2,343,464	$ 1,434,706	$ 1,537,740	**$ 1,625,519**
42	Number of Miles of Main - Plastic	17.3	48.5	36.5	102.3
43	2023 Preliminary Actual EIRP Costs - Plastic	$40,655,999	$69,578,082	$56,088,205	$166,322,286
44	TOD Project (ALM3) (6.62miles)		$10,230,205		$10,230,205
45	Carry-Over & Future Year ($M)				$5,374,140
46	2023 Preliminary Actual EIRP Capital Expenditures				**$181,926,631**
47	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**)				$ 3,550,319
48	**2023 actual total EIRP Program and Facilities capital expenditures**				**$ 185,476,950**
49					
50	**2024 projected capital expeditures:**				
51	2024 Forecasted Cost Per Mile - Plastic	$ 1,306,077	$ 1,382,187	$ 1,365,542	**$ 1,353,912**
52	Number of Miles of Main - Plastic	36.6	42.4	47.4	126.4
53	2024 Forecasted EIRP Costs - Plastic	$47,802,418	$58,660,016	$64,672,069	$171,134,504
54	TOD/HP Steel Projects - 8.24 miles	$13,965,551	$0	$5,473,207	$19,438,758
55	Carry-Over & Future Year ($M)	$1,077,625	$2,255,727	$1,680,468	$5,013,820
56	2024 Projected EIRP Capital Expenditures				**$195,587,082**
57	**Projected 10 month ending October 31, 2024**				**$ 172,399,356**
58	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**)				$ 6,088,574
59	**2024 forecasted total EIRP Program and Facilities capital expenditures**				**$ 201,675,656**
60					
61	**2025 projected capital expeditures:**				
62	2025 Forecasted Cost Per Mile - Plastic	$ 1,306,077	$ 1,382,187	$ 1,365,542	**$ 1,357,800**
63	Number of Miles of Main - Plastic	25.8	36.2	58.5	120.5
64	2025 Forecasted EIRP Costs - Plastic	$33,719,049	$50,024,540	$79,847,224	$163,590,813
65	TOD/HP Steel Projects - 21.5 miles	$17,100,000	$60,800,000	$3,800,000	$81,700,000
66	Carry-Over & Future Year ($M)	$1,000,000	$2,100,000	$1,900,000	$5,000,000
67	2025 Projected EIRP Capital Expenditures				**$250,290,813**
68	**Projected 10 month ending October 31, 2025**				**$ 207,322,168**
69	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**)				$ -
70	**2025 forecasted total EIRP Program and Facilities capital expenditures**				**$ 250,290,813**
71					
72	**2026 projected capital expeditures:**				
73	2026 Forecasted Cost Per Mile - Plastic	$ 1,345,259	$ 1,423,653	$ 1,406,508	**$ 1,404,251**
74	Number of Miles of Main - Plastic	20.4	55.0	60.9	136.2
75	2026 Forecasted EIRP Costs - Plastic	$27,457,048	$78,265,841	$85,597,258	$191,320,148
76	TOD/HP Steel Projects - 14.1 miles	$41,019,906	$9,747,936	$4,507,772	$55,275,613
77	Carry-Over & Future Year ($M)	$1,000,000	$2,100,000	$1,900,000	$5,000,000
78	2026 Projected EIRP Capital Expenditures				**$ 251,595,761**
79	**Projected 12 month ending October 31, 2026**				**$ 251,371,734**
80	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**)				$ -
81	**2026 forecasted total EIRP Program and Facilities capital expenditures**				**$ 251,595,761**

(1) Reference: 2023 EIRP Annual Performance Report filing U-21308

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
Exhibit No.: A-84 (KAP-6)
Page: 3 of 3
Witness: KAPascarello
Date: December 2024

Line #		Company Regions			
		Southwest (SW)	Northeast (NE)	Southeast (SE)	Total
	Company Costs:				
1	**2018 Actual Total**				
2	Total Services Renewal, Retired Tie-overs	649	1,411	2,563	4,623
3	**Miles Main Installed**	**13.26**	**15.20**	**24.37**	**52.8**
4	Total Service/Miles	49	93	105	88
5	Project Cost ($M)	$34.7	$12.7	$37.3	$84.6
6	Carry-Over & Future Year ($M)	$.9	$.3	$1.0	$2.2
7	**Total Cost ($(Million)**	**$35.6**	**$13.0**	**$38.2**	**$86.8**
8	**Cost per Mile**	**$ 2,684,825**	**$ 853,844**	**$ 1,567,901**	**$ 1,642,797**
9					
10	**2019 Actual Total**				
11	Total Services Renewal, Retired Tie-overs	643	1,087	3,192	4,922
12	**Miles Main Installed**	**8.86**	**11.30**	**30.57**	**50.7**
13	Total Service/Miles	73	96	104	97
14	Project Cost ($M)	$12.7	$12.6	$48.2	$73.5
15	Carry-Over & Future Year ($M)	$.9	$.8	$3.2	$4.9
16	**Total Cost ($(Million)**	**$13.5**	**$13.4**	**$51.5**	**$78.4**
17	**Cost per Mile**	**$ 1,527,539**	**$ 1,185,190**	**$ 1,683,162**	**$ 1,545,060**
18					
19	**2020 Actual Total**				
20	Total Services Renewal, Retired Tie-overs	641	1,500	6,373	8,514
21	**Miles Main Installed**	**10.22**	**15.50**	**45.55**	**71.3**
22	Total Service/Miles	63	97	140	119
23	Project Cost ($M)	$15.2	$21.9	$76.9	$114.0
24	Carry-Over & Future Year ($M)	$.6	$.9	$3.0	$4.5
25	**Total Cost ($(Million)**	**$15.8**	**$22.8**	**$80.0**	**$118.5**
26	**Cost per Mile**	**$ 1,544,687**	**$ 1,470,051**	**$ 1,755,749**	**$ 1,663,349**
27					
28	**2021 Actual Total**				
29	Total Services Renewal, Retired Tie-overs	5,000	3,794	5,014	13,808
30	**Miles Main Installed**	**68.94**	**45.53**	**42.70**	**157.2**
31	Total Service/Miles	73	83	117	88
32	Project Cost ($M)	$72.0	$86.2	$67.9	$226.1
33	Carry-Over & Future Year ($M)	$.3	$1.9	$2.5	$4.7
34	**Total Cost ($(Million)**	**$72.3**	**$88.1**	**$70.4**	**$230.8**
35	**Cost per Mile**	**$ 1,048,660**	**$ 1,934,649**	**$ 1,648,117**	**$ 1,468,180**
36					
37	**2022 Actual Total**				
38	Total Services Renewal, Retired Tie-overs	3,622	4,327	6,125	14,074
39	**Miles Main Installed**	**51.40**	**66.10**	**44.60**	**162.1**
40	Total Service/Miles	70	65	137	87
41	Project Cost ($M)	$58.9	$92.9	$76.5	$228.4
42	Carry-Over & Future Year ($M)	$6.3	$5.7	$7.7	$19.8
43	**Total Cost ($(Million)**	**$65.3**	**$98.6**	**$84.3**	**$248.1**
44	**Cost per Mile**	**$ 1,269,571**	**$ 1,491,824**	**$ 1,889,774**	**$ 1,530,842**

(1) Reference: EIRP Annual Performance Report filing for each year

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Distribution Plant - Material Condition and Gas Operations Other
Summary of Actual & Projected Gas and Common Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-85 (KAP-7)
Page: 1 of 1
Witness: KAPascarello
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
				Capital Expenditures			
Line No.	**Program Description**	**Historic Test Year 2023 Actual**	**Last Rate Case Approved Spending Plan Case No. U-21490 12 mos. Ending 9/30/2025 (1)**	**Last Rate Case Actual Spending Case No. U-21490 12 mos. Ending 9/30/2025 (3)**	**Variation Percentage (1)**	**Location of Testimony Regarding Significant Var (1)(3) (>10%)**	**Current Case Projection 12 mos. Ending 10/31/2026**
1	Material Condition (non-EIRP)	84,370	n/a	n/a	n/a	n/a	134,293
2	Material Condition- EIRP[2]	181,927	215,300	n/a	n/a	n/a	251,372
3	Gas Operations Other	7,750	n/a	n/a	n/a	n/a	17,090
4	**Total Capital**	274,046	215,300	-			402,755

Footnotes:

[1] Case No. U-21490 resulted in a settlement agreement that did not state approved capital spending amounts for the programs represented here except as noted below

[2] The Order in Case No. U-21490 specifically approved an annual EIRP expenditure of $215.3 million for the 12 months ending 9/30/2025

[3] The projected test year in Case U-21490 has not transpired as of the date of this filing

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Operations, Maintenance & Metering, Field Services, Other Operations
($000)

Case No.: U-21806
Exhibit No.: A-86 (JPP-1)
Page: 1 of 1
Witness: JPPnacek
Date: December 2024

Line No.	Description	2023 Actuals	2024 Projected	2025 Projected	Projected 12-Mos Ending Oct 31, 2026
		(a)	(b)	(c)	(d)	(e)
1	**Operations, Maintenance & Metering**	**86,376**	**89,946**	**96,190**	**107,391**
	Labor	55,185	56,116	56,488	62,090
	Material	2,771	3,060	3,377	3,740
	Contractor	5,746	6,038	5,470	6,632
	Non-Labor Overheads	10,206	10,519	10,284	11,422
	Non-Labor Other	12,468	14,212	20,572	23,507
2	**Field Operations Services**	**19,031**	**19,033**	**18,407**	**22,037**
	Labor	12,137	12,409	13,190	15,075
	Material	157	123	72	126
	Contractor	58	62	67	70
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	6,680	6,438	5,079	6,767
3	**Compliance & Controls**	**2,053**	**0**	**0**	**0**
	Labor	1,448	0	0	0
	Material	0	0	0	0
	Contractor	135	0	0	0
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	471	0	0	0
4	**Operations Performance**	**3,005**	**2,320**	**2,502**	**2,539**
	Labor	2,353	1,817	1,959	1,988
	Material	0	0	0	0
	Contractor	4	3	3	3
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	648	501	540	548
5	**Operations Management**	**834**	**1,701**	**1,643**	**1,668**
	Labor	1,167	1,088	1,052	1,068
	Material	67	136	131	133
	Contractor	0	0	0	0
	Non-Labor Overheads	0	0	0	0
	Non-Labor Other	(400)	476	460	467
6	**Total "Description of Area" O&M Expenses**	**$ 111,299**	**$ 113,000**	**$ 118,743**	**$ 133,635**
	Labor	72,290	71,430	72,688	80,220
	Material	2,995	3,320	3,580	3,999
	Contractor	5,942	6,104	5,540	6,706
	Non-Labor Overheads	10,206	10,519	10,284	11,422
	Non-Labor Other	19,867	21,628	26,651	31,288

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Operations, Maintenance & Metering Programs
($000)

Case No.: U-21806
Exhibit No.: A-87 (JPP-2)
Page: 1 of 3
Witness: JPPnacek
Date: December 2024

Line No.		Description	(a) 2023 Actuals	(b) 2024 Projected	(c) 2025 Projected	(d) Projected 12-Mos Ending Oct 31, 2026
1		**Distribution Cathodic Protection**	**2,554**	**1,989**	**1,835**	**2,915**
	52%	Labor	1,324	1,031	952	1,512
	1%	Material	24	19	17	27
	27%	Contractor	684	532	491	781
	9%	Non-Labor Overheads	240	187	172	274
	11%	Non-Labor Other	282	220	203	322
2		**Operations & Maint Pipeline - Distribution**	**8,925**	**10,815**	**9,067**	**11,512**
	58%	Labor	5,169	6,263	5,251	6,667
	8%	Material	710	860	721	916
	24%	Contractor	2,105	2,551	2,138	2,715
	16%	Non-Labor Overheads	1,417	1,717	1,440	1,828
	-5%	Non-Labor Other	(476)	(577)	(484)	(614)
3		**Operations & Maint Pipeline - Transmission**	**3,831**	**3,456**	**3,017**	**3,741**
	59%	Labor	2,272	2,050	1,790	2,219
	2%	Material	78	70	61	76
	10%	Contractor	393	354	309	383
	16%	Non-Labor Overheads	624	563	492	610
	12%	Non-Labor Other	464	418	365	453
4		**Operations & Maint Regulation-Distribution**	**8,436**	**8,078**	**8,048**	**8,497**
	71%	Labor	6,018	5,763	5,741	6,061
	6%	Material	467	447	445	470
	4%	Contractor	296	283	282	298
	16%	Non-Labor Overheads	1,358	1,300	1,295	1,368
	4%	Non-Labor Other	298	286	284	300
5		**Operations & Maint-M&R-Transmission**	**3,497**	**3,434**	**3,258**	**3,384**
	59%	Labor	2,064	2,027	1,923	1,997
	9%	Material	310	305	289	300
	5%	Contractor	180	177	167	174
	20%	Non-Labor Overheads	705	692	656	682
	7%	Non-Labor Other	238	234	222	230
6		**Odor Response**	**6,309**	**6,259**	**5,641**	**6,441**
	89%	Labor	5,597	5,553	5,004	5,714
	0%	Material	0	0	0	0
	0%	Contractor	4	4	4	4
	0%	Non-Labor Overheads	24	24	21	24
	11%	Non-Labor Other	684	678	611	698
7		**Leak Repair & Survey**	**14,866**	**16,715**	**16,760**	**17,680**
	45%	Labor	6,674	7,504	7,524	7,937
	2%	Material	247	277	278	293
	4%	Contractor	580	652	654	690
	12%	Non-Labor Overheads	1,845	2,074	2,080	2,194
	37%	Non-Labor Other	5,520	6,207	6,224	6,565
8		**Damage Repair**	**1,415**	**1,448**	**1,255**	**1,381**
	153%	Labor	2,168	2,219	1,924	2,117
	3%	Material	48	49	42	47
	10%	Contractor	146	149	129	142
	47%	Non-Labor Overheads	664	680	590	649
	-114%	Non-Labor Other	(1,611)	(1,649)	(1,430)	(1,574)
9		**Staking**	**12,408**	**15,316**	**22,654**	**24,457**
	8%	Labor	999	1,233	1,823	1,968
	0%	Material	9	11	17	18
	1%	Contractor	75	92	136	147
	3%	Non-Labor Overheads	319	394	583	629
	89%	Non-Labor Other	11,006	13,586	20,095	21,695
10		**Customer Requested Services**	**18,877**	**18,259**	**19,679**	**20,394**
	88%	Labor	16,617	16,072	17,323	17,953
	1%	Material	188	182	196	204
	1%	Contractor	136	132	142	147
	11%	Non-Labor Overheads	2,025	1,959	2,111	2,188
	0%	Non-Labor Other	(90)	(87)	(93)	(97)
11		**Meter First Set Credits**	**(6,942)**	**(8,104)**	**(8,490)**	**(7,960)**
	0%	Labor	-	-	-	-
	0%	Material	-	-	-	-
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	100%	Non-Labor Other	(6,942)	(8,104)	(8,490)	(7,960)
12		**ROW Clearing**	**1,767**	**1,624**	**1,614**	**2,048**
	31%	Labor	542	498	495	628
	0%	Material	7	7	7	8
	5%	Contractor	82	75	75	95
	7%	Non-Labor Overheads	118	109	108	137
	58%	Non-Labor Other	1,018	935	929	1,179
13		**Meter Reading**	**2,607**	**2,568**	**2,624**	**2,804**
	79%	Labor	2,054	2,023	2,067	2,209
	0%	Material	1	1	1	1
	0%	Contractor	1	1	1	1
	1%	Non-Labor Overheads	27	26	27	29
	20%	Non-Labor Other	525	517	529	565
14		**Meter Tech & Mgmt Sys Support**	**1,532**	**2,110**	**3,831**	**3,999**
	62%	Labor	950	1,308	2,376	2,480
	29%	Material	440	606	1,100	1,148
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	9%	Non-Labor Other	142	196	355	371
15		**Smart Energy MTC - Gas**	**544**	**555**	**554**	**554**
	0%	Labor	-	-	-	-
	0%	Material	-	-	-	-
	23%	Contractor	125	128	127	127
	0%	Non-Labor Overheads	-	-	-	-
	77%	Non-Labor Other	419	427	427	427
16		**Gas Storage** (note: excludes facilities chargebacks)	**5,739**	**5,356**	**4,772**	**5,473**
	48%	Labor	2,735	2,552	2,274	2,608
	4%	Material	243	227	202	232
	16%	Contractor	934	871	776	890
	15%	Non-Labor Overheads	837	781	696	798
	17%	Non-Labor Other	991	925	824	945
17		**Replace Vintage Services**	**14**	**70**	**70**	**71**
	28%	Labor	4	20	20	20
	0%	Material	0	0	0	0
	54%	Contractor	7	38	38	38
	18%	Non-Labor Overheads	2	13	13	13
	0%	Non-Labor Other	0	0	0	0
18		**Total Operations, Maintenance & Metering**	**86,376**	**89,946**	**96,190**	**107,391**
		Labor	55,185	56,116	56,488	62,090
		Material	2,771	3,060	3,377	3,740
		Contractor	5,746	6,038	5,470	6,632
		Non-Labor Overheads	10,206	10,519	10,284	11,422
		Non-Labor Other	12,468	14,212	20,572	23,507

*** Notes:
% breakdown for cost elements is based on 2023 actual
2026 Test Year is based on a monthly cash flow average using 2018 - 2023 history

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Operations Maintenance & Metering Programs
($000)
NOTE: NOT IN USE. INFLATION SET TO 0%

Case No.: U-21806
Exhibit No.: A-87 (JPP-2)
Page: 2 of 3
Witness: JPPnacek
Date: December 2024

Line No.	Description	(a)	(b) Actual 12 Mos Ending Dec 31, 2023	(c) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2023	(d) Merit & Inflation 12 Mos Ending Dec 31, 2024	(e) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	(f) Merit & Inflation 12 Mos Ending Dec 31, 2025	(g) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	(h) Merit & Inflation 10 Mos Ending Oct 31, 2026	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending Oct 31, 2026
					(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	**Distribution Cathodic Protection**		**2,554**	**1,575**	**0**	**1,575**	**0**	**1,575**	**0**	**362**	**2,915**
	Labor		1,324	345	0	345	0	345	0	187	1,512
	Material		24	24	0	24	0	24	0	3	27
	Contractor		684	684	0	684	0	684	0	97	781
	Non-Labor Overheads		240	240	0	240	0	240	0	34	274
	Non-Labor Other		282	282	0	282	0	282	0	40	322
2	**Operations & Maint Pipeline - Distribution**		**8,925**	**4,027**	**0**	**4,027**	**0**	**4,027**	**0**	**2,587**	**11,512**
	Labor		5,169	272	0	272	0	272	0	1,498	6,667
	Material		710	710	0	710	0	710	0	206	916
	Contractor		2,105	2,105	0	2,105	0	2,105	0	610	2,715
	Non-Labor Overheads		1,417	1,417	0	1,417	0	1,417	0	411	1,828
	Non-Labor Other		(476)	(476)	0	(476)	0	(476)	0	(138)	(614)
3	**Operations & Maint Pipeline - Transmission**		**3,831**	**1,803**	**0**	**1,803**	**0**	**1,803**	**0**	**(89)**	**3,741**
	Labor		2,272	244	0	244	0	244	0	(53)	2,219
	Material		78	78	0	78	0	78	0	(2)	76
	Contractor		393	393	0	393	0	393	0	(9)	383
	Non-Labor Overheads		624	624	0	624	0	624	0	(15)	610
	Non-Labor Other		464	464	0	464	0	464	0	(11)	453
4	**Operations & Maint Regulation-Distribution**		**8,436**	**2,770**	**0**	**2,770**	**0**	**2,770**	**0**	**61**	**8,497**
	Labor		6,018	352	0	352	0	352	0	43	6,061
	Material		467	467	0	467	0	467	0	3	470
	Contractor		296	296	0	296	0	296	0	2	298
	Non-Labor Overheads		1,358	1,358	0	1,358	0	1,358	0	10	1,368
	Non-Labor Other		298	298	0	298	0	298	0	2	300
5	**Operations & Maint-M&R-Transmission**		**3,497**	**1,493**	**0**	**1,493**	**0**	**1,493**	**0**	**(113)**	**3,384**
	Labor		2,064	61	0	61	0	61	0	(67)	1,997
	Material		310	310	0	310	0	310	0	(10)	300
	Contractor		180	180	0	180	0	180	0	(6)	174
	Non-Labor Overheads		705	705	0	705	0	705	0	(23)	682
	Non-Labor Other		238	238	0	238	0	238	0	(8)	230
6	**Odor Response**		**6,309**	**6,112**	**0**	**6,112**	**0**	**6,112**	**0**	**132**	**6,441**
	Labor		5,597	5,400	0	5,400	0	5,400	0	117	5,714
	Material		0	0	0	0	0	0	0	0	0
	Contractor		4	4	0	4	0	4	0	0	4
	Non-Labor Overheads		24	24	0	24	0	24	0	1	24
	Non-Labor Other		684	684	0	684	0	684	0	14	698
7	**Leak Repair & Survey**		**14,866**	**9,413**	**0**	**9,413**	**0**	**9,413**	**0**	**2,814**	**17,680**
	Labor		6,674	1,221	0	1,221	0	1,221	0	1,263	7,937
	Material		247	247	0	247	0	247	0	47	293
	Contractor		580	580	0	580	0	580	0	110	690
	Non-Labor Overheads		1,845	1,845	0	1,845	0	1,845	0	349	2,194
	Non-Labor Other		5,520	5,520	0	5,520	0	5,520	0	1,045	6,565
8	**Damage Repair**		**1,415**	**(635)**	**0**	**(635)**	**0**	**(635)**	**0**	**(33)**	**1,381**
	Labor		2,168	119	0	119	0	119	0	(51)	2,117
	Material		48	48	0	48	0	48	0	(1)	47
	Contractor		146	146	0	146	0	146	0	(3)	142
	Non-Labor Overheads		664	664	0	664	0	664	0	(16)	649
	Non-Labor Other		(1,611)	(1,611)	0	(1,611)	0	(1,611)	0	38	(1,574)
9	**Staking**		**12,408**	**11,468**	**0**	**11,468**	**0**	**11,468**	**0**	**12,050**	**24,457**
	Labor		999	59	0	59	0	59	0	970	1,968
	Material		9	9	0	9	0	9	0	9	18
	Contractor		75	75	0	75	0	75	0	72	147
	Non-Labor Overheads		319	319	0	319	0	319	0	310	629
	Non-Labor Other		11,006	11,006	0	11,006	0	11,006	0	10,689	21,695
10	**Customer Requested Services**		**18,877**	**3,411**	**0**	**3,411**	**0**	**3,411**	**0**	**1,518**	**20,394**
	Labor		16,617	1,150	0	1,150	0	1,150	0	1,336	17,953
	Material		188	188	0	188	0	188	0	15	204
	Contractor		136	136	0	136	0	136	0	11	147
	Non-Labor Overheads		2,025	2,025	0	2,025	0	2,025	0	163	2,188
	Non-Labor Other		(90)	(90)	0	(90)	0	(90)	0	(7)	(97)
11	**Meter First Set Credits**		**(6,942)**	**0**	**0**	**0**	**0**	**0**	**0**	**(1,018)**	**(7,960)**
	Labor		0	0	0	0	0	0	0	0	0
	Material		0	0	0	0	0	0	0	0	0
	Contractor		0	0	0	0	0	0	0	0	0
	Non-Labor Overheads		0	0	0	0	0	0	0	0	0
	Non-Labor Other		(6,942)	0	0	0	0	0	0	(1,018)	(7,960)
12	**ROW Clearing**		**1,767**	**1,418**	**0**	**1,418**	**0**	**1,418**	**0**	**281**	**2,048**
	Labor		542	193	0	193	0	193	0	86	628
	Material		7	7	0	7	0	7	0	1	8
	Contractor		82	82	0	82	0	82	0	13	95
	Non-Labor Overheads		118	118	0	118	0	118	0	19	137
	Non-Labor Other		1,018	1,018	0	1,018	0	1,018	0	162	1,179
13	**Meter Reading**		**2,607**	**2,478**	**0**	**2,478**	**0**	**2,478**	**0**	**197**	**2,804**
	Labor		2,054	1,924	0	1,924	0	1,924	0	155	2,209
	Material		1	1	0	1	0	1	0	0	1
	Contractor		1	1	0	1	0	1	0	0	1
	Non-Labor Overheads		27	27	0	27	0	27	0	2	29
	Non-Labor Other		525	525	0	525	0	525	0	40	565
14	**Meter Tech & Mgmt Sys Support**		**1,532**	**1,084**	**0**	**1,084**	**0**	**1,084**	**0**	**2,467**	**3,999**
	Labor		950	502	0	502	0	502	0	1,530	2,480
	Material		440	440	0	440	0	440	0	708	1,148
	Contractor		0	0	0	0	0	0	0	0	0
	Non-Labor Overheads		0	0	0	0	0	0	0	0	0
	Non-Labor Other		142	142	0	142	0	142	0	229	371
15	**Smart Energy MTC - Gas**		**544**	**544**	**0**	**544**	**0**	**544**	**0**	**10**	**554**
	Labor		0	0	0	0	0	0	0	0	0
	Material		0	0	0	0	0	0	0	0	0
	Contractor		125	125	0	125	0	125	0	2	127
	Non-Labor Overheads		0	0	0	0	0	0	0	0	0
	Non-Labor Other		419	419	0	419	0	419	0	8	427
										0	
16	**Gas Storage** (note: excludes facilities chargebacks)		**5,739**	**3,349**	**0**	**3,349**	**0**	**3,349**	**0**	**(267)**	**5,473**
	Labor		2,735	344	0	344	0	344	0	(127)	2,608
	Material		243	243	0	243	0	243	0	(11)	232
	Contractor		934	934	0	934	0	934	0	(43)	890
	Non-Labor Overheads		837	837	0	837	0	837	0	(39)	798
	Non-Labor Other		991	991	0	991	0	991	0	(46)	945
17	**Replace Vintage Services**		**14**	**10**	**0**	**10**	**0**	**10**	**0**	**57**	**71**
	Labor		4	0	0	0	0	0	0	16	20
	Material		0	0	0	0	0	0	0	0	0
	Contractor		7	7	0	7	0	7	0	31	38
	Non-Labor Overheads		2	2	0	2	0	2	0	10	13
	Non-Labor Other		0	0	0	0	0	0	0	0	0
18	**Total Operations, Maintenance & Metering**		**86,376**	**50,318**	**0**	**50,318**	**0**	**50,318**	**0**	**21,015**	**107,391**
	Labor		55,185	12,186	0	12,186	0	12,186	0	6,905	62,090
	Material		2,771	2,771	0	2,771	0	2,771	0	969	3,740
	Contractor		5,746	5,746	0	5,746	0	5,746	0	887	6,632
	Non-Labor Overheads		10,206	10,206	0	10,206	0	10,206	0	1,217	11,422
	Non-Labor Other		12,468	19,411	0	19,411	0	19,411	0	11,038	23,507

Notes

Base Labor is all labor cost elements less OM&C & Indirect Labor

		12-Mo Ending 2024	12-Mo Ending 2025	10-Mo Ending 2026
19	Annual merit and inflation rates per WP-HLR-44			
	Annual inflation rates	0.0%	0.0%	0.0%
	Number of months in the period	12	12	10
	Pro-rated inflation rate	0.0%	0.0%	0.0%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Historic O&M Expenses from 2016 to 2023
Operations, Maintenance & Metering Programs
($000)

Case No.: U-21806
Exhibit No.: A-87 (JPP-2)
Page: 3 of 3
Witness: JPPnacek
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)		(i)
Line No.	Description	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	Notes
	Operations, Maintenance & Metering									
1	**Distribution Cathodic Protection**	**2,378**	**2,783**	**3,763**	**2,478**	**3,190**	**3,140**	**2,678**	**2,554**	
	Labor	1,366	1,834	2,161	1,699	1,762	1,492	1,513	1,324	
	Material	12	32	39	16	22	69	18	24	
	Contractor	809	613	1,038	348	811	971	487	684	
	Non-Labor Overheads	90	145	318	223	247	243	266	240	
	Non-Labor Other	101	159	207	192	348	365	393	282	
2	**Operations & Maint Pipeline - Distributior**	**5,788**	**6,879**	**8,241**	**7,999**	**7,850**	**11,721**	**10,531**	**8,925**	
	Labor	3,817	4,090	4,969	4,627	4,705	6,701	5,723	5,169	
	Material	320	462	543	490	451	711	772	710	
	Contractor	1,046	1,646	1,829	2,346	2,107	2,943	2,664	2,105	
	Non-Labor Overheads	395	552	1,082	1,020	1,044	1,802	1,794	1,417	
	Non-Labor Other	210	130	-183	-485	(457)	(436)	(421)	(476)	
3	**Operations & Maint Pipeline - Transmissior**	**2,675**	**2,131**	**2,670**	**3,122**	**3,013**	**3,199**	**4,222**	**3,831**	
	Labor	1,622	1,462	1,795	1,993	1,801	1,767	2,168	2,272	
	Material	65	55	68	118	128	105	385	78	
	Contractor	545	111	164	216	352	175	197	393	
	Non-Labor Overheads	188	194	320	450	358	482	706	624	
	Non-Labor Other	255	308	322	344	373	671	767	464	
4	**Operations & Maint Regulation-Distribution**	**4,609**	**4,331**	**6,169**	**5,910**	**6,364**	**7,663**	**9,127**	**8,436**	
	Labor	4,019	3,703	4,498	4,664	4,878	5,379	6,488	6,018	
	Material	131	70	419	152	285	206	347	467	
	Contractor	5	6	21	23	42	37	61	296	
	Non-Labor Overheads	329	402	633	794	835	1,244	1,585	1,358	
	Non-Labor Other	125	152	597	277	324	796	645	298	
5	**Operations & Maint-M&R-Transmission**	**2,434**	**3,461**	**3,074**	**3,005**	**2,898**	**3,189**	**4,339**	**3,497**	
	Labor	1,382	1,594	1,629	1,668	1,607	1,683	1,973	2,064	
	Material	323	400	291	271	386	247	496	310	
	Contractor	269	295	436	205	204	215	428	180	
	Non-Labor Overheads	152	214	284	373	408	497	763	705	
	Non-Labor Other	307	959	433	487	293	547	680	238	
6	**Odor Response**	**6,340**	**4,522**	**5,265**	**6,147**	**5,506**	**6,159**	**6,445**	**6,309**	
	Labor	5,947	4,180	4,778	5,479	4,845	5,259	5,566	5,597	
	Material	4	0	0	0	1	0	-	0	
	Contractor	13	0	3	0	12	11	4	4	
	Non-Labor Overheads	195	342	464	647	40	28	28	24	
	Non-Labor Other	180	0	20	21	609	862	847	684	
7	**Leak Repair & Survey**	**13,511**	**10,909**	**16,088**	**20,233**	**19,803**	**21,787**	**18,942**	**14,866**	
	Labor	9,518	6,921	9,487	11,654	11,935	11,260	9,775	6,674	
	Material	282	166	177	275	336	334	429	247	
	Contractor	508	545	720	1,250	1,227	1,295	1,103	580	
	Non-Labor Overheads	925	1,157	2,234	3,356	2,134	2,696	2,969	1,845	
	Non-Labor Other	2,278	2,120	3,469	3,698	4,171	6,201	4,666	5,520	
8	**Damage Repair**	**1,209**	**624**	**683**	**1,102**	**2,550**	**1,380**	**1,575**	**1,415**	
	Labor	1,676	1,702	2,020	2,177	2,958	2,146	2,644	2,168	
	Material	35	84	72	41	56	41	61	48	
	Contractor	64	99	136	161	162	96	150	146	
	Non-Labor Overheads	184	218	451	528	544	655	1,014	664	
	Non-Labor Other	-750	-1,478	-1,996	-1,805	(1,170)	(1,557)	(2,295)	(1,611)	
9	**Staking**	**5,145**	**5,829**	**6,754**	**8,200**	**7,306**	**10,983**	**10,309**	**12,408**	
	Labor	1,166	665	736	3,573	1,139	1,617	985	999	
	Material	0	0	7	6	1	1	5	9	
	Contractor	14	36	56	-1,129	(76)	51	77	75	
	Non-Labor Overheads	132	88	167	349	267	442	345	319	
	Non-Labor Other	3,834	5,040	5,789	5,401	5,975	8,872	8,898	11,006	
10	**Customer Requested Services**	**14,468**	**15,411**	**15,885**	**16,711**	**12,114**	**15,520**	**19,198**	**18,877**	
	Labor	13,210	14,100	14,218	14,709	10,590	13,056	16,288	16,617	
	Material	65	72	219	137	111	123	226	188	
	Contractor	116	77	72	257	142	325	421	136	
	Non-Labor Overheads	766	1,073	1,301	1,546	1,213	1,920	2,286	2,025	
	Non-Labor Other	311	89	76	63	57	96	(23)	(90)	
11	**Meter First Set Credits**	**(4,918)**	**(6,783)**	**(6,637)**	**(7,064)**	**(6,810)**	**(7,063)**	**(5,451)**	**(6,942)**	
	Labor	0	-25	0	0	-	-	-	-	
	Material	0	0	0	0	-	-	-	-	
	Contractor	0	0	0	0	-	-	-	-	
	Non-Labor Overheads	0	0	0	0	-	-	-	-	
	Non-Labor Other	-4,918	-6,758	-6,637	-7,064	(6,810)	(7,063)	(5,451)	(6,942)	
12	**ROW Clearing**	**86**	**536**	**1,095**	**359**	**1,148**	**1,845**	**1,827**	**1,767**	
	Labor	63	143	199	50	219	320	313	542	
	Material	0	7	25	0	3	37	25	7	
	Contractor	20	19	5	0	1	1	11	82	
	Non-Labor Overheads	0	6	22	1	8	-	-	118	
	Non-Labor Other	3	360	844	308	917	1,486	1,479	1,018	
13	**Meter Reading**	**13,582**	**12,328**	**10,499**	**7,633**	**4,097**	**2,831**	**2,592**	**2,607**	
	Labor	11,310	9,762	8,537	5,950	3,207	2,065	2,024	2,054	
	Material	2	2	0	0	-	-	1	1	
	Contractor	77	1	0	0	-	7	-	1	
	Non-Labor Overheads	10	16	17	18	14	19	19	27	
	Non-Labor Other	2,182	2,548	1,945	1,665	877	741	547	525	
14	**Meter Tech & Mgmt Sys Support**	**1,266**	**1,283**	**1,349**	**1,312**	**1,085**	**1,269**	**1,427**	**1,532**	
	Labor	1,199	1,219	1,266	1,228	870	1,056	1,109	950	
	Material	0	0	0	0	-	-	150	440	
	Contractor	0	0	0	0	0	-	-	-	
	Non-Labor Overheads	0	0	0	0	3	-	-	-	
	Non-Labor Other	67	65	83	85	212	213	168	142	
15	**Smart Energy MTC - Gas**	**0**	**847**	**599**	**606**	**543**	**566**	**542**	**544**	
	Labor	0	1,182	0		0	-	-	-	
	Material	0	21	0		-	-	-	-	
	Contractor	0	0	-17	102	125	125	94	125	
	Non-Labor Overheads	0	0	0		-	-	-	-	
	Non-Labor Other	0	-357	616	504	418	441	448	419	
16	**Gas Storage** (note: excludes facilities chargebacks)	**7,139**	**6,118**	**6,412**	**6,265**	**5,821**	**5,860**	**6,338**	**5,739**	
	Labor	3,538	2,975	2,781	3,419	2,830	3,226	3,261	2,735	
	Material	258	323	810	425	301	354	426	243	
	Contractor	2,090	386	619	381	359	612	764	934	
	Non-Labor Overheads	8	9	12	11	9	25	116	837	
	Non-Labor Other	1,246	2,425	2,190	2,029	2,322	1,643	1,771	991	
17	**Replace Vintage Services**	**0**	**1**	**103**	**90**	**84**	**298**	**98**	**14**	
	Labor	0	1	56	49	44	125	12	4	
	Material	0	0	0	0	5	0	0	0	
	Contractor	0	0	0	0	7	59	78	7	
	Non-Labor Overheads	0	0	44	36	1	105	7	2	
	Non-Labor Other	0	0	3	4	27	9	1	0	
18	**Total "Operations, Maintenance & Metering" O&M Expens**	**$ 75,712**	**$ 71,209**	**$ 82,013**	**$ 84,108**	**$ 76,562**	**$ 90,346**	**$ 94,740**	**86,376**	
	Labor	59,833	55,506	59,131	62,939	53,389	57,152	59,843	55,185	
	Material	1,497	1,697	2,672	1,931	2,088	2,230	3,342	2,771	
	Contractor	5,577	3,832	5,082	4,161	5,474	6,923	6,538	5,746	
	Non-Labor Overheads	3,376	4,414	7,350	9,352	7,125	10,156	11,898	10,206	
	Non-Labor Other	5,430	5,761	7,778	5,725	8,486	13,886	13,119	12,468	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Field Operations Services
($000)

Case No.: U-21806
Exhibit No.: A-88 (JPP-3)
Page: 1 of 3
Witness: JPPnacek
Date: December 2024

Line No.		(a) Description	(b) 2023 Actuals	(c) 2024 Projected	(d) 2025 Projected	(e) Projected 12-Mos Ending Oct 31, 2026
1		**Training**	**4,736**	**4,150**	**4,607**	**4,844**
	91%	Labor	4,317	3,783	4,199	4,416
	0%	Material	4	4	4	4
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	9%	Non-Labor Other	415	364	404	425
2		**Tools**	**1,828**	**1,438**	**789**	**1,431**
	26%	Labor	476	375	205	373
	8%	Material	148	117	64	116
	0%	Contractor	2	2	1	2
	0%	Non-Labor Overheads	-	-	-	-
	66%	Non-Labor Other	1,201	945	519	941
3		**Field Operations Expenses**	**3,463**	**3,776**	**2,727**	**3,624**
	1%	Labor	25	28	20	26
	0%	Material	-	-	-	-
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	99%	Non-Labor Other	3,437	3,748	2,707	3,597
4		**Indirect Labor/Labor Variation**	**(1,100)**	**-**	**-**	**-**
	114%	Labor	(1,252)	-	-	-
	0%	Material	1	-	-	-
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	-14%	Non-Labor Other	151	-	-	-
5		**Supervision / Admin-Staff - Distribution**	**3,327**	**3,670**	**3,979**	**4,095**
	85%	Labor	2,826	3,118	3,380	3,479
	0%	Material	-	-	-	-
	2%	Contractor	53	58	63	65
	0%	Non-Labor Overheads	-	-	-	-
	13%	Non-Labor Other	448	494	536	551
6		**Supervision / Admin-Staff - Services**	**1,297**	**1,239**	**1,314**	**1,324**
	90%	Labor	1,170	1,117	1,184	1,193
	0%	Material	-	-	-	-
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	10%	Non-Labor Other	128	122	130	131
7		**Supervision / Admin-Staff - Transmission & Storage**	**953**	**606**	**384**	**393**
	79%	Labor	751	478	303	310
	0%	Material	-	-	-	-
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	21%	Non-Labor Other	202	128	81	83
8		**Gas Dispatch & Scheduling**	**1,180**	**1,102**	**1,239**	**1,278**
	98%	Labor	1,151	1,075	1,209	1,247
	0%	Material	-	-	-	-
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	2%	Non-Labor Other	29	27	30	31
9		**EIRP O&M**	**3,348**	**3,051**	**3,368**	**5,048**
	80%	Labor	2,674	2,436	2,689	4,031
	0%	Material	4	3	4	6
	0%	Contractor	2	2	2	4
	0%	Non-Labor Overheads	-	-	-	-
	20%	Non-Labor Other	668	609	672	1,008
10		**Total Field Operations Services**	**19,031**	**19,033**	**18,407**	**22,037**
		Labor	12,137	12,409	13,190	15,075
		Material	157	123	72	126
		Contractor	58	62	67	70
		Non-Labor Overheads	-	-	-	-
		Non-Labor Other	6,680	6,438	5,079	6,767

*** Notes:
% breakdown for cost elements is based on 2023 actual
2026 Test Year is based on a monthly cash flow average using 2018 - 2023 history

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Field Operations Services
($000)
NOTE: NOT IN USE. INFLATION SET TO 0%

Case No.: U-21806
Exhibit No.: A-88 (JPP-3)
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Witness: JPPnacek
Date: December 2024

Line No.	Description	(a)	(b) Actual 12 Mos Ending Dec 31, 2023	(c) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2023	(d) Merit & Inflation 12 Mos Ending Dec 31, 2024 (c) * Inflation Rate	(e) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	(f) Merit & Inflation 12 Mos Ending Dec 31, 2025 (e) * Inflation Rate	(g) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	(h) Merit & Inflation 9 Mos Ending Oct 31, 2026 (g) * Inflation Rate	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending Oct 31, 2026 (b) + (d) + (f) + (h) + (i)
1	**Training**		**4,736**	**430**	**0**	**430**	**0**	**430**	**0**	**109**	**4,844**
	Labor		4,317	11	0	11	0	11	0	99	4,416
	Material		4	4	0	4	0	4	0	0	4
	Contractor		0	0	0	0	0	0	0	0	0
	Non-Labor Overheads		0	0	0	0	0	0	0	0	0
	Non-Labor Other		415	415	0	415	0	415	0	10	425
2	**Tools**		**1,828**	**1,828**	**0**	**1,828**	**0**	**1,828**	**0**	**(397)**	**1,431**
	Labor		476	476	0	476	0	476	0	(103)	373
	Material		148	148	0	148	0	148	0	(32)	116
	Contractor		2	2	0	2	0	2	0	(1)	2
	Non-Labor Overheads		0	0	0	0	0	0	0	0	0
	Non-Labor Other		1,201	1,201	0	1,201	0	1,201	0	(261)	941
3	**Field Operations Expenses**		**3,463**	**3,463**	**0**	**3,463**	**0**	**3,463**	**0**	**161**	**3,624**
	Labor		25	25	0	25	0	25	0	1	26
	Material		0	0	0	0	0	0	0	0	0
	Contractor		0	0	0	0	0	0	0	0	0
	Non-Labor Overheads		0	0	0	0	0	0	0	0	0
	Non-Labor Other		3,437	3,437	0	3,437	0	3,437	0	160	3,597
4	**Indirect Labor/Labor Variation**		**(1,100)**	**152**	**0**	**152**	**0**	**152**	**0**	**1,100**	**0**
	Labor		(1,252)	0	0	0	0	0	0	1,252	0
	Material		1	1	0	1	0	1	0	(1)	0
	Contractor		0	0	0	0	0	0	0	0	0
	Non-Labor Overheads		0	0	0	0	0	0	0	0	0
	Non-Labor Other		151	151	0	151	0	151	0	(151)	0
5	**Supervision / Admin-Staff - Distribution**		**3,327**	**3,331**	**0**	**3,331**	**0**	**3,331**	**0**	**769**	**4,095**
	Labor		2,826	2,830	0	2,830	0	2,830	0	653	3,479
	Material		0	0	0	0	0	0	0	0	0
	Contractor		53	53	0	53	0	53	0	12	65
	Non-Labor Overheads		0	0	0	0	0	0	0	0	0
	Non-Labor Other		448	448	0	448	0	448	0	103	551
6	**Supervision / Admin-Staff - Services**		**1,297**	**1,297**	**0**	**1,297**	**0**	**1,297**	**0**	**26**	**1,324**
	Labor		1,170	1,170	0	1,170	0	1,170	0	23	1,193
	Material		0	0	0	0	0	0	0	0	0
	Contractor		0	0	0	0	0	0	0	0	0
	Non-Labor Overheads		0	0	0	0	0	0	0	0	0
	Non-Labor Other		128	128	0	128	0	128	0	3	131
7	**Supervision / Admin-Staff - Transmission & Storage**		**953**	**953**	**0**	**953**	**0**	**953**	**0**	**(560)**	**393**
	Labor		751	751	0	751	0	751	0	(441)	310
	Material		0	0	0	0	0	0	0	0	0
	Contractor		0	0	0	0	0	0	0	0	0
	Non-Labor Overheads		0	0	0	0	0	0	0	0	0
	Non-Labor Other		202	202	0	202	0	202	0	(119)	83
8	**Gas Dispatch & Scheduling**		**1,180**	**1,180**	**0**	**1,180**	**0**	**1,180**	**0**	**99**	**1,278**
	Labor		1,151	1,151	0	1,151	0	1,151	0	96	1,247
	Material		0	0	0	0	0	0	0	0	0
	Contractor		0	0	0	0	0	0	0	0	0
	Non-Labor Overheads		0	0	0	0	0	0	0	0	0
	Non-Labor Other		29	29	0	29	0	29	0	2	31
9	**EIRP O&M**		**3,348**	**1,341**	**0**	**1,341**	**0**	**1,341**	**0**	**1,700**	**5,048**
	Labor		2,674	666	0	666	0	666	0	1,357	4,031
	Material		4	4	0	4	0	4	0	2	6
	Contractor		2	2	0	2	0	2	0	1	4
	Non-Labor Overheads		0	0	0	0	0	0	0	0	0
	Non-Labor Other		668	668	0	668	0	668	0	339	1,008
10	**Total Field Operations Services**		**19,031**	**13,974**	**0**	**13,974**	**0**	**13,974**	**0**	**3,006**	**22,037**
	Labor		12,137	7,080	0	7,080	0	7,080	0	2,938	15,075
	Material		157	157	0	157	0	157	0	(31)	126
	Contractor		58	58	0	58	0	58	0	13	70
	Non-Labor Overheads		0	0	0	0	0	0	0	0	0
	Non-Labor Other		6,680	6,680	0	6,680	0	6,680	0	87	6,767

Notes

Base Labor is all labor cost elements less OM&C & Indirect Labor

		12-Mo Ending 2024	12-Mo Ending 2025	10-Mo Ending 2026
11	Annual merit and inflation rates per WP-HLR-44			
	Annual inflation rates	0.0%	0.0%	0.0%
	Number of months in the period	12	12	10
	Pro-rated inflation rate	0.0%	0.0%	0.0%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Historic O&M Expenses from 2016 to 2023
Field Operations Services
($000)

Case No.: U-21806
Exhibit No.: A-88 (JPP-3)
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Witness: JPPnacek
Date: December 2024

Line No.	(a) Description	(b) 2016 Actual	(c) 2017 Actual	(d) 2018 Actual	(e) 2019 Actual	(f) 2020 Actual	(g) 2021 Actual	(h) 2022 Actual	2023 Actuals	(i) Notes
	Field Operations Services									
1	**Training**	**5,142**	**5,719**	**6,787**	**6,146**	**4,698**	**6,247**	**6,206**	**4,736**	
	Labor	4,393	4,963	6,148	5,698	4,116	5,689	5,829	4,317	
	Material	9	20	15	6	4	4	5	4	
	Contractor	81	2	(0)	3	0	0	0	-	
	Non-Labor Overheads	26	1	0	0	0	1	2	-	
	Non-Labor Other	632	733	623	439	577	552	370	415	
2	**Tools**	**1,806**	**1,939**	**2,137**	**1,703**	**1,786**	**1,691**	**3,066**	**1,828**	
	Labor	253	344	323	259	334	427	448	476	
	Material	259	386	452	234	231	170	182	148	
	Contractor	0	8	50	26	17	19	15	2	
	Non-Labor Overheads	0	841	936	803	0	0	0	-	
	Non-Labor Other	1,293	360	375	381	1,204	1,076	2,421	1,201	
3	**Field Operations Expenses**	**4,071**	**4,039**	**3,223**	**3,134**	**2,964**	**3,709**	**3,900**	**3,463**	
	Labor	321	(276)	(774)	31	36	6	16	25	
	Material	0	0	0	0	0	0	0	-	
	Contractor	3	0	0	0	0	0	699	-	
	Non-Labor Overheads	0	829	823	995	0	0	0	-	
	Non-Labor Other	3,746	3,486	3,175	2,108	2,928	3,704	3,185	3,437	
4	**Indirect Labor/Labor Variation**	**1,145**	**231**	**756**	**(399)**	**569**	**2,620**	**1,386**	**(1,100)**	
	Labor	1,058	159	655	(549)	537	2,568	1,316	(1,252)	
	Material	0	0	0	2	0	1	0	1	
	Contractor	0	0	0	0	0	0	0	-	
	Non-Labor Overheads	0	0	0	0	0	0	0	-	
	Non-Labor Other	87	73	101	149	33	52	70	151	
5	**Supervision / Admin-Staff - Distribution**	**8,735**	**6,141**	**5,894**	**5,895**	**4,940**	**3,832**	**3,378**	**3,327**	
	Labor	7,165	5,093	4,918	4,922	4,446	3,437	2,775	2,826	
	Material	0	5	0	1	0	0	0	-	
	Contractor	0	0	0	0	0	0	0	53	
	Non-Labor Overheads	0	0	0	0	0	0	0	-	
	Non-Labor Other	1,570	1,043	976	972	494	395	603	448	
6	**Supervision / Admin-Staff - Services**	**0**	**0**	**0**	**0**	**0**	**1,008**	**1,396**	**1,297**	
	Labor						912	1,231	1,170	
	Material						2	0	-	
	Contractor						0	0	-	
	Non-Labor Overheads						0	0	-	
	Non-Labor Other						94	165	128	
7	**Supervision / Admin-Staff - Transmission & Storage**	**0**	**0**	**0**	**0**	**0**	**1,979**	**571**	**953**	
	Labor						686	443	751	
	Material						0	0	-	
	Contractor						2	1	-	
	Non-Labor Overheads						0	0	-	
	Non-Labor Other						1,291	127	202	
8	**Gas Dispatch & Scheduling**	**0**	**0**	**0**	**0**	**0**	**1,465**	**1,372**	**1,180**	
	Labor	0	0	0	0	0	1,438	1,310	1,151	
	Material	0	0	0	0	0	0	0	-	
	Contractor	0	0	0	0	0	0	0	-	
	Non-Labor Overheads	0	0	0	0	0	0	0	-	
	Non-Labor Other	0	0	0	0	0	27	62	29	
9	**EIRP O&M**	**2,309**	**2,416**	**1,996**	**2,496**	**5,463**	**3,682**	**4,370**	**3,348**	
	Labor	1,931	1,888	1,512	2,047	4,856	3,054	3,473	2,674	
	Material	4	1	0	3	2	4	1	4	
	Contractor	41	3	0	2	64	21	1	2	
	Non-Labor Overheads	0	1	0	0	0	0	0	-	
	Non-Labor Other	333	523	484	445	541	603	895	668	
10	**Total "Operations, Maintenance & Metering" O&M Expenses**	**23,207**	**20,485**	**20,793**	**18,974**	**20,420**	**26,235**	**25,645**	**19,031**	
	Labor	15,122	12,170	12,783	12,408	14,325	18,218	16,840	12,137	
	Material	273	413	467	245	238	180	189	157	
	Contractor	125	13	50	31	81	42	717	58	
	Non-Labor Overheads	26	1,671	1,759	1,798	0	1	2	-	
	Non-Labor Other	7,661	6,217	5,734	4,493	5,777	7,794	7,896	6,680	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Actual & Projected O&M Expenses
Other Operations
($000)

Case No.: U-21806
Exhibit No.: A-89 (JPP-4)
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Witness: JPPnacek
Date: December 2024

Line No.		(a) Description	(b) 2023 Actuals	(c) 2024 Projected	(d) 2025 Projected	(e) Projected 12-Mos Ending Oct 31, 2026
1		**Compliance & Controls**	**2,053**	**-**	**-**	**-**
		Labor	1,448	-	-	-
		Material	-	-	-	-
		Contractor	135	-	-	-
		Non-Labor Overheads	-	-	-	-
		Non-Labor Other	471	-	-	-
2		**Work Management and Customer Delivery**	**3,005**	**2,320**	**2,502**	**2,539**
	78%	Labor	2,353	1,817	1,959	1,988
	0%	Material	-	-	-	-
	0%	Contractor	4	3	3	3
	0%	Non-Labor Overheads	-	-	-	-
	22%	Non-Labor Other	648	501	540	548
3		**Operations Management**	**834**	**1,701**	**1,643**	**1,668**
	64%	Labor	1,167	1,088	1,052	1,068
	8%	Material	67	136	131	133
	0%	Contractor	-	-	-	-
	0%	Non-Labor Overheads	-	-	-	-
	28%	Non-Labor Other	(400)	476	460	467
4		**Total Other Operations**	**5,892**	**4,021**	**4,146**	**4,207**
		Labor	4,968	2,905	3,011	3,055
		Material	67	136	131	133
		Contractor	138	3	3	3
		Non-Labor Overheads	-	-	-	-
		Non-Labor Other	719	977	1,000	1,015

*** Notes:
% breakdown for cost elements is based on 2023 actual
2025 Test Year is based on a monthly cash flow average using 2018 - 2023 history

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Other Operations
($000)
NOTE: NOT IN USE. INFLATION SET TO 0%

Case No.: U-21806
Exhibit No.: A-89 (JPP-4)
Page: 2 of 3
Witness: JPPnacek
Date: December 2024

Line No.	Description	(a)	(b) Actual 12 Mos Ending Dec 31, 2023	(c) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2023	(d) Merit & Inflation 12 Mos Ending Dec 31, 2024	(e) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	(f) Merit & Inflation 12 Mos Ending Dec 31, 2025	(g) Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	(h) Merit & Inflation 9 Mos Ending Oct 31, 2026	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending Oct 31, 2026
					(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	**Compliance & Controls**		**2,053**	**0**	**0**	**0**	**0**	**0**	**0**	**(2,053)**	**0**
	Labor		1,448	0	0	0	0	0	0	(1,448)	0
	Material		-	0	0	0	0	0	0	0	0
	Contractor		135	0	0	0	0	0	0	(135)	0
	Non-Labor Overheads		-	0	0	0	0	0	0	0	0
	Non-Labor Other		471	0	0	0	0	0	0	(471)	0
2	**Work Management and Customer Delivery**		**3,005**	**3,057**	**0**	**3,057**	**0**	**3,057**	**0**	**(466)**	**2,539**
	Labor		2,353	2,405	0	2,405	0	2,405	0	(365)	1,988
	Material		-	0	0	0	0	0	0	0	0
	Contractor		4	4	0	4	0	4	0	(1)	3
	Non-Labor Overheads		-	0	0	0	0	0	0	0	0
	Non-Labor Other		648	648	0	648	0	648	0	(101)	548
3	**Operations Management**		**834**	**463**	**0**	**463**	**0**	**463**	**0**	**834**	**1,668**
	Labor		1,167	796	0	796	0	796	0	(99)	1,068
	Material		67	67	0	67	0	67	0	66	133
	Contractor		-	0	0	0	0	0	0	0	0
	Non-Labor Overheads		-	0	0	0	0	0	0	0	0
	Non-Labor Other		(400)	(400)	0	(400)	0	(400)	0	867	467
4	**Total Other Operations**		**5,892**	**3,521**	**0**	**3,521**	**0**	**3,521**	**0**	**(1,685)**	**4,207**
	Labor		4,968	3,201	0	3,201	0	3,201	0	(1,913)	3,055
	Material		67	67	0	67	0	67	0	66	133
	Contractor		138	4	0	4	0	4	0	(135)	3
	Non-Labor Overheads		-	0	0	0	0	0	0	0	0
	Non-Labor Other		719	248	0	248	0	248	0	296	1,015

Notes

Base Labor is all labor cost elements less OM&C & Indirect Labor

		12-Mo Ending 2024	12-Mo Ending 2025	10-Mo Ending 2026
5	Annual merit and inflation rates per WP-HLR-44			
	Annual inflation rates	0.0%	0.0%	0.0%
	Number of months in the period	12	12	10
	Pro-rated inflation rate	0.0%	0.0%	0.0%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Historic O&M Expenses from 2016 to 2023
Other Operations
($000)

Case No.: U-21806
Exhibit No.: A-89 (JPP-4)
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Witness: JPPnacek
Date: December 2024

Line No.	(a) Description	(b) 2016 Actual	(c) 2017 Actual	(d) 2018 Actual	(e) 2019 Actual	(f) 2020 Actual	(g) 2021 Actual	(h) 2022 Actual	(i) 2023 Actuals	(j) Notes
	Operations Other									
1	**Compliance & Controls**	**0**	**0**	**0**	**818**	**1,688**	**2,177**	**2,819**	**2,053**	
	Labor				624	1,323	1,461	1,684	1,448	
	Material				0	-	-	-	-	
	Contractor				13	12	253	551	135	
	Non-Labor Overheads				0	-	-	-	-	
	Non-Labor Other				181	353	463	584	471	
2	**Work Management and Customer Delivery**	**772**	**859**	**1,118**	**1,141**	**1,005**	**3,211**	**4,955**	**3,005**	Formerly Gas Ops Performance for 2016 - 2023
	Labor	708	764	966	991	882	2,479	2,906	2,353	
	Material	0	0	0	0	-	0	0	-	
	Contractor	23	26	22	16	-	-	1,331	4	
	Non-Labor Overheads	0	0	0	0	-	-	-	-	
	Non-Labor Other	41	68	129	134	123	733	717	648	
3	**Planning and Scheduling**	**4,097**	**3,293**	**2,974**	**2,873**	**2,520**	**-**	**-**	**-**	
	Labor	3,892	3,128	2,825	2,729	2,353	-	-	-	
	Material	0	0	0	0	-	-	-	-	
	Contractor	0	0	0	0	-	-	-	-	
	Non-Labor Overheads	0	0	0	0	-	-	-	-	
	Non-Labor Other	205	165	149	144	167	-	-	-	
4	**Operations Management**	**2,195**	**922**	**965**	**1,213**	**1,943**	**1,580**	**2,094**	**1,250**	
	Labor	1,559	695	660	797	784	851	941	796	
	Material	0	1	111	47	814	367	657	100	
	Contractor	0	0	0	0	-	-	-	-	
	Non-Labor Overheads	0	0	0	0	-	-	-	-	
	Non-Labor Other	636	226	195	369	345	362	496	354	
5	**Total "Operations, Maintenance & Metering" O&M Expenses**	**$ 7,064**	**$ 5,073**	**$ 5,056**	**$ 6,045**	**$ 7,156**	**$ 6,968**	**$ 9,867**	**$ 6,308**	
	Labor	6,159	4,587	4,451	5,141	5,343	4,791	5,531	4,597	
	Material	0	1	111	47	814	367	657	100	
	Contractor	23	26	22	29	12	253	1,882	138	
	Non-Labor Overheads	0	0	0	0	0	0	0	-	
	Non-Labor Other	882	458	472	828	987	1,558	1,797	1,473	

Consumers Energy Company
Manufactured Gas Plant Sites Information

Line No.	(a) Location	(b) Size (Acres)	(c) Estimated Peak Plant Capacity (CFD)	(d) Date Acquired or Built by CPCo	(e) Date Natural Gas Arrived	(f) Date Put on Standby	(g) Date Plant Retired	(h) Date Holder Retired	(i) Current Owner	(j) Current Use	(k) Current Site Status
1	Alma	1.2	340,000	1934	1936	1936?	1948	1951	GPM Investments LLC Consumers Energy Messenger Properties LLC	Gasoline Station Regulator Station Parking lot	Remedial Action Monitoring
2	Alpena	1	250,000	1934	NA	1946(a)			Consumers Energy C. McCoy	Vacant lot Residential home	NFA (site proper) - 2021
3	Bay City	4.7	1,500,000	1922	1933	1924(b)	1942	1954	Bay Riverfront Development LLC Bay City	Parking lot Electrical substation / Vacant lot	NFA (site proper) - 2022 NFA (off-site) - 2024
4	Charlotte	1.7	50,000	1927	1929		1929(c)	1954	Consumers Energy	Regulator Station	NFA in preparation
5	Flint Court St	37.8	5,400,000	1927	1942	1942	1945	1953	Consumers Energy	Service Center	Remedial Action Monitoring
6	Flint East St.	6.5	6,000,000	1922	1942	1928	1951	1954	Consumers Energy United States Postal Service U of M - Flint City of Flint	Parking lot Post Office Parking lot East Blvd.	Remedial Action Monitoring
7	Grand Ledge	1	30,000	1926	1936?		1926(c)	1934	Consumers Energy CSX Railroad	Vacant lot Railroad Right-of-Way	NFA (site proper) - 2016
8	Hastings	0.8	240,000	1922	1936		1931(c)	1954	Consumers Energy Cary Display	Regulator Station Vacant Lot	NFA (site proper) - 2024
9	Ionia	2.6	50,000	1925	1936		1931(c)	1954	Consumers Energy	Vacant lot	NFA - 2013
10	Jackson	7.5	3,800,000	1922	1942	1942	1947	1956	Consumers Energy Jackson Glass Southridge Park Apartments City of Jackson	Fleet garage, vacant lot, regulator station Glass / windshield repair Apartment complex Franklin and Cooper ROWs	Remedial Action Monitoring
11	Kalamazoo	7	3,500,000	1917	1943	1943	1956	1958	Zoetis	Pharmaceuticals	NFA in preparation
12	Lansing	20	3,200,000	1925	1936	1936	1945	1956	Consumers Energy	Service Center	Remedial Action Monitoring
13	Manistee	0.7	150,000	1922	1950		1950	1952?	Consumers Energy American Legion 254 River Street, LLC City of Manistee	Vacant lot Parking lot Warehouse (driveway) Vacant Right-of-Way	NFA (Operational Site) - 2023 Remedial Action Monitoring (former Relief Holder Site) Certificate of Completion (Manistee River Sediments) - 2022
14	Marshall	1.6	190,000	1934	1943		1943	1963	City of Marshall	Assisted Living Center	NFA - 2019
15	Mt. Clemens	1.6	800,000	1934	1941	1941?	1942	1953	Consumers Energy Mt. Clemens DPW	Vacant Building, regulator station Public Works Yard	NFA (site proper) - 2021
16	Owosso	5.1	510,000	1934	1942		1935(d)	1954	Consumers Energy	Vacant lot and Regulator Station	Remedial Action Monitoring
17	Plymouth	1.1	120,000	1934	1942		1942	1955	Messina Concrete Junction Plymouth LLC Shiloh Management Corp	RediMix Plant Warehouse Office/Warehouse	Remedial Action Monitoring
18	Pontiac	9	4,500,000	1922	1942	1942	1949	1955	Consumers Energy City of Pontiac AKZO Nobel Coatings	Fenced Vacant Property Woodlots Parking Lot	Remedial Action Monitoring
19	Royal Oak	19	8,000,000	1932	1941	1941	1951	1954	Consumers Energy	Service Center	NFA - 2021
20	Saginaw	5.8	1,000,000	1922	1933	1924(b)	1942	1953	City of Saginaw Consumers Energy	Public Works Office Gas regulator station	Remedial Action Monitoring
21	St. Johns	0.7	50,000	1934	1942	1934?(e)		1952	FCM Development LLC	Parking Lot and residential apartments	NFA (site proper) - 2023
22	Sault Ste. Marie	1.5	240,000	1934	NA	1945(a)			MCM Marine, Inc. MCM Properties LLP	Marine contractor and construction company	Certificate of Completion - 2021
23	Zilwaukee	14	3,000,000	1924	1933	1933	1951	1953	Sargent Docks & Terminal Co.	Bulk Material Staging	NFA in preparation

(a) Date sold
(b) Switched to gas produced by Zilwaukee MGP
(c) Switched to gas produced by Lansing MGP
(d) Switched to gas produced by Flint MGP
(e) Switched to gas produced by Owosso MGP
? Date uncertain

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.:	U-21806
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Date:	December 2024

Consumers Energy Company

MGP Environmental Response Cash Outflows - January 2024 to December 2024 by Phase & Site

Line No.	(a) SITE	(b) RI	(c) FS	(d) RA	(e) NFA	(f) TOTAL
1	Alma	$0	$0	$0	$0	$0
2	Alpena	$0	$0	$0	$0	$0
3	Bay City	$0	$0	$0	$8,000	$8,000
4	Charlotte	$0	$0	$0	$6,955	$6,955
5	Flint Court	$0	$0	$0	$0	$0
6	Flint East	$0	$0	$28,650	$21,885	$50,535
7	Grand Ledge	$0	$0	$0	$0	$0
8	Hastings	$0	$0	$0	$6,210	$6,210
9	Ionia	$0	$0	$0	$0	$0
10	Jackson	$0	$0	$20,000	$42,500	$62,500
11	Kalamazoo	$0	$0	$28,000	$28,000	$56,000
12	Lansing	$0	$0	$0	$0	$0
13	Manistee	$0	$0	$337,000	$11,200	$348,200
14	Marshall	$0	$0	$0	$0	$0
15	Mt. Clemens	$0	$0	$0	$0	$0
16	Owosso	$0	$0	$235,000	$0	$235,000
17	Plymouth	$57,000	$0	$104,825	$0	$161,825
18	Pontiac	$0	$0	$0	$7,500	$7,500
19	Royal Oak	$0	$0	$0	$0	$0
20	Saginaw	$0	$0	$0	$0	$0
21	St. Johns	$0	$0	$0	$5,000	$5,000
22	SS Marie	$0	$0	$0	$0	$0
23	Zilwaukee	$0	$0	$0	$48,800	$48,800
24	**TOTAL**	$57,000	$0	$753,475	$186,050	$996,525

TOTAL RI	TOTAL FS	TOTAL RA	NFA
$57,000	$0	$753,475	$186,050

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Pension and OPEB Volatility Mechanism
Regulatory Asset/Liability Amortization Expense
($000)

Case No.: U-21806
Exhibit No.: A-92 (HLR-51)
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Witness: HLRayl
Date: December 2024

Line No.	(a) Description	(b) Source	(c) 2023	(d) 2024	(e) 2025	(f) 2026
1	Pension volatility mechanism asset / (liability)	WP-KKG-16, 17, and 18	$ 266	$ (4,364)	$ (4,573)	
2	2023 pension volatility mechanism amortization	Line 1, col. (c) / 10 years	-	27	27	27
3	2024 pension volatility mechanism amortization	Line 1, col. (d) / 10 years	-	-	(436)	(436)
4	2025 pension volatility mechanism amortization	Line 1, col. (e) / 10 years	-	-	-	(457)
5	Total amortization expense	Sum of Lines 2 through 4	-	27	(410)	(867)
6	OPEB volatility mechanism asset / (liability)	WP-KKG-16, 17, and 18	(655)	(7,776)	(6,956)	
7	2023 OPEB volatility mechanism amortization	Line 6, col. (c) / 10 years	-	(65)	(65)	(65)
8	2024 OPEB volatility mechanism amortization	Line 6, col. (d) / 10 years	-	-	(778)	(778)
9	2025 OPEB volatility mechanism amortization	Line 6, col. (e) / 10 years	-	-	-	(696)
10	Total amortization expense	Sum of Lines 7 through 9	-	(65)	(843)	(1,539)
			12 Months Ending 10/31/2025	**12 Months Ending 10/31/2026**	**Average Balance 10/31/2026**	
11	Test year pension amortization expense	(Line 5, col. (e)) ÷ 12 * 2) + (Line 5, col. (f)) ÷ 12 * 10)		(791)		
12	Test year OPEB amortization expense	(Line 10, col. (e)) ÷ 12 * 2) + (Line 10, col. (f)) ÷ 12 * 10)		(1,423)		
13	Total test year amortization expense	Line 11 + Line 12		(2,214)		
14	Pension volatility mechanism deferred balance	See Notes {1}, {2}, and {3} below, respectively	(7,594)	(7,565)	(7,579)	
15	OPEB volatility mechanism deferred balance	See Notes {4}, {5}, and {6} below, respectively	(13,459)	(13,196)	(13,328)	

Notes

{1} [Line 1, col. (c) + (d) - Line 5, col. (c) + (d)] + [(Line 1, col. (e) ÷ 12 * 10) - Line 5, col. (e) ÷ 12 * 10)]
{2} Sum of line 1, col. (c) through (e) - sum of line 5, col. (c) through (e) - ((line 5, col. (f) ÷ 12 * 10)
{3} (Line 14, col. + line 14, col.) ÷ 2
{4} [Line 6, col. (c) + (d) - Line 10, col. (c) + (d)] + [(Line 6, col. (e) ÷ 12 * 10) - Line 10, col. (e) ÷ 12 * 10)]
{5} Sum of line 6, col. (c) through (e) - sum of line 10, col. (c) through (e) - ((line 10, col. (f) ÷ 12 * 10)
{6} (Line 15, col. + line 15, col.) ÷ 2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Test Year Discount and Carrying Cost Rates
for the Customer Attachment Program

Case No.: U-21806
Exhibit No.: A-93 (SAS-7)
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	(a)	(b)	(c)	(d)	(e)	(f)
		Capital Structure				
Line No.	**Description**	**Amount Outstanding ($000,000)** [1]	**% of Permanent Capital**	**Cost Rate** [1]	**After Tax Weighted Cost of Permanent Capital**	**Pre Tax Weighted Cost of Permanent Capital**
1	Long-Term Debt	12,645	49%	4.35%	2.14%	2.14%
2	Preferred Stock	37	0.14%	4.50%	0.01%	0.01%
3	Common Equity	13,070	50.75%	10.25%	5.20%	6.96%
4	Total Permanent Capital	$ 25,752				
5	Discount Rate				7.35%	
6	Carrying Cost Rate					9.11%

Notes
[1] Exhibit A-14 (MRB-1), Schedule D-1, page 1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Calculation of Home Products Credit

Case No.: U-21806
Exhibit No.: A-94 (SAS-8)
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Witness: SASmith
Date: December 2024

Line No.	Description	(a) Test Year Sales [1]	(b) Home Products Gain Share	(c) Home Products Total Credit
		MMcf	$000	$/Mcf (b) / (a)
1	Residential Service	157,950	$ (21,196)	$ (0.1342)
	General Service			
2	Small Service GS-1	29,949	(2,723)	$ (0.0909)
3	Medium Service GS-2	30,200	(1,666)	$ (0.0552)
4	Large Service GS-3	8,183	(365)	$ (0.0446)
5	Total General Service	68,331	(4,753)	
	Transportation			
6	Small Transport ST	18,679	(584)	$ (0.0313)
7	Large Transport LT	18,970	(418)	$ (0.0220)
8	Extremely Large Transport XLT	27,277	(426)	$ (0.0156)
9	Extra Extremely Large Transport XXLT	16,528	(123)	$ (0.0074)
10	Total Transportation	81,455	(1,551)	
11	Total	307,736	$ (27,500)	

Notes
[1] Exhibit A-15 (MA-7), Schedule E-3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2024 EICP Operational Goals

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Exhibit No.: A-95 (AEM-1)
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Employee Incentive Compensation Plan - Metric Explanation and Measurement or Calculation Method

Line	(a)	(b) Metric	(c) Explanation	(d) Measurement or Calculation Method
1	Employee Safety	**Recordable Incident Rate**	Recordable Incident Rate is the number of recordable injuries multiplied by 200,000 (industry standard) divided by the total hours worked	# of recordable injuries * 200,000 / total hours worked
2		**High Risk Injuries**	Number of injuries (Recordable and Non-Recordable) that are classified against the EEI Safety Classification Learning Model as High Risk which includes: HSIF & PSIF	# of injuries classified as HSIF & PSIF
3	Culture Index	**Employee Engagement Index**	The Employee Engagement index is an average favorability score derived from the taking the total favorable responses received for the 5 questions within the Employee Engagement Category from each of the Company's employee engagement surveys administered by Korn Ferry and they use Qualtrics as the survey platform (https://www.qualtrics.com/) and dividing by the total number of responses received. The Company's Engagement, Empowerment and Diversity, Equity and Inclusion indexes are how we measure our culture values in action. The indexes focus on things like ensuring we have simple processes, fix problems, keep our workforce engaged by measuring the combination of emotional commitment (are you proud to work here?) and rational commitment (do you plan to stay?) and embed diversity, equity and inclusion into everything we do.	This index is an average of the scores of 5 questions: 1.If I were offered a similar job elsewhere at the same pay, I would stay at the company. 2.How likely is it that you would recommend this company's products and services to family and friends? 3.I feel motivated to do more than is required of me. 4.Given your choice, how long would you plan to continue working for the company? (Less than 1 year, 1-2 years, 3-5 years, More than 5 years/until retirement) 5.I would recommend my Company as a good place to work.
4		**Employee Empowerment Index**	The Employee Empowerment index is an average favorability score derived from the taking the total favorable responses received for the 5 questions within the Employee Empowerment Category from each of the Company's employee engagement surveys administered by Korn Ferry and they use Qualtrics as the survey platform (https://www.qualtrics.com/) and dividing by the total number of responses received. The Company's Engagement, Empowerment and Diversity, Equity and Inclusion indexes are how we measure our culture values in action. The indexes focus on things like ensuring we have simple processes, fix problems, keep our workforce engaged by measuring the combination of emotional commitment (are you proud to work here?) and rational commitment (do you plan to stay?) and embed diversity, equity and inclusion into everything we do.	This index is an average of the scores of 5 questions: 1)I feel encouraged to come up with new and better ways of doing things. 2) I am involved in decisions that affect my work. 3) Our existing processes are efficient and effective. 4) There is a reasonable balance between my work and personal life. 5) People at my Company fix problems so that they don't happen again.
5		**Diversity, Equity & Inclusion Index**	The Diversity, Equity and Inclusion index is an average favorability score derived from the taking the total favorable responses received for the 5 questions within the Diversity, Equity and Inclusion Category from each of the Company's employee engagement surveys administered by Korn Ferry and they use Qualtrics as the survey platform (https://www.qualtrics.com/) and dividing by the total number of responses received. The Company's Engagement, Empowerment and Diversity, Equity and Inclusion indexes are how we measure our culture values in action. The indexes focus on things like ensuring we have simple processes, fix problems, keep our workforce engaged by measuring the combination of emotional commitment (are you proud to work here?) and rational commitment (do you plan to stay?) and embed diversity, equity and inclusion into everything we do.	This index is an average of the scores of 5 questions. 1.Employees are encouraged to participate in making decisions that affect their work 2.My immediate manager values having individuals in my work group with diverse backgrounds and perspectives 3.I feel able to be myself at work 4.I feel like I belong at Consumers Energy 5.Opportunities for advancement are available to employees regardless of personal background or characteristics
6		**Customer Experience Index**	Customer Experience Index is a survey administered by Forrester (https://go.forrester.com/analytics/) and is a measure of customer service based on 3 questions – Did we meet your needs? Was it easy to do business with us? Was the experience enjoyable.	The metric is calculated by asking those 3 questions of customers on a scale of 1 to 5 with 4s and 5s being positive responses, 1s and 2s being negative responses, and 3s being a neutral response. To calculate the score, the number of negative responses is subtracted by the number of positive responses, which is then divided by the total number of customers responding. The results of the three questions are averaged together to calculate the Customer Experience Index score.
7		**Electric Reliability**	Electric Reliability/SAIDI (System Average Interruption Duration Index) is a utility-industry benchmark; SAIDI measures the total time an average customer experiences a non-momentary power interruption in a one-year period.	Use of IEEE (Institute of Electrical and Electronics Engineers) 2.5beta standard to exclude outlier events/MEDs (Major Event Dates); total customer-minutes of interruption divided by total customers served (i.e. customers on the system).
8		**Methane Emmisions Reduction**	Reduce fugitive methane emissions associated with gas distribution by 422 metric tons. Reductions are obtained as a result of replacing and/or retiring older, aging infrastructure from natural gas distribution.	Summation of reduction in methane emissions associated with Vintage Service Replacements (VSR), Enhanced Infrastructure Replacement Program (EIRP), Other Non-Vintage Replacements (Mains & Services), Well Plug & Abandonment (P&A) and capital replacements from the Leak Back-log. See sub-categories below for more details. **Vintage Service Replacements** - The methane emission reductions are calculated using emission factors (EFs) for the type of service replaced (copper and Bare steel). The EFs and formulas used are consistent with those defined in EPA's Greenhouse Gas Reporting Rule. **EIRP** - The methane emission reductions are calculated using EFs for the type of main or service replaced. EFs for mains are based on miles replaced while services, as with VSRs above, are based on the number of services. The EFs and formulas used are consistent with those defined in EPA's Greenhouse Gas Reporting Rule. **Other Mains & Services** - same calculations as VSR and EIRP. **Well Plug & Abandon** - The methane emission reductions are calculated using emission factors (EFs) for the type of component retired. The EFs and formulas used are consistent with those defined in EPA's Greenhouse Gas Reporting Rule. **Gas Leak Backlog** - same calculation as VSR.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Customer Benefits: Employee Safety

Case No.: U-21806
Exhibit No.: A-96 (AEM-2)
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Witness: AEMeschke
Date: December 2024

CE Employee Safety

424.86 Average of daily run rate of Non-Exempt & Union from P&C

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	LOST TIME			**Lost Days**	**Lost Days**	**Lost Days**			
1	**Year**	**# Safety Incidents**	**# Lost Days**	**Per Incident**	**Cost Per Year**	**Per Incident**	**Workers Comp, Other Exposure (Annual actual paid Workers Compensation benefits**	**Per Incident**	
2	2020	102	3191	31.3	$ 1,355,728	$ 13,291	$ 2,123,847	$ 20,822	
3	2021	135	3207	23.8	$ 1,362,526	$ 10,093	$ 1,306,947	$ 9,681	
4	2022	107	2993	28.0	$ 1,271,606	$ 11,884	$ 2,752,881	$ 25,728	
5	2023	125	2598	20.8	$ 1,103,786	$ 8,830	$ 1,980,835	$ 15,847	
6	**Average**	117.25	2997.25	25.6	$ 1,273,412	$ 10,861	$ 2,041,127	$ 17,408	
7	**2024 Target**	83	2122	23.8	$ 901,434	$ 10,860.65	$ 1,444,892	$ 17,641	
									Total
8	**Projected Savings**	**11**	**876**		**$ 371,977**		**$ 596,236**		**$ 968,213**

9	**Indirect Cost Savings**	**$655,859**	Notes: 1.1 Multiplier per OSHA Pays Software
10	**GRAND TOTAL**	**$ 1,624,072**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Customer Benefits: Reliability

Case No.: U-21835
Exhibit No.: A-97 (AEM-3)
Page: 1 of 1
Witness: AEMeschke
Date: December 2024

SYSTEM AVERAGE INTERRUPTION DURATION INDEX - SAIDI

Estimated Societal Benefits of Customer Reliability

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Customers [2]	Cost of	COI Std	SAIDI [4]		Cost/(Benefit) to Society [5]					
Line No.	Description [1]	2024	Interruption [3]	Deviation [3]	2020-2023	2024	Min	Average	Max	Min	Average	Max
		(000)	($ per min)	($ per min)	(min / cust)	(min / cust)	($000)	($000)	($000)	($000 per min)	($000 per min)	($000 per min)
1	Residential	1,651.0	$ 0.03	$ 0.04	195	170	$ 134	$ (1,361)	$ (2,857)	$ 5	$ (54)	$ (114)
2	Small C&I	230.0	11.65	7.73	195	170	(22,541)	(66,982)	(111,423)	(902)	(2,679)	(4,457)
3	Medium / Large C&I	1.9	185.19	100.56	195	170	(4,020)	(8,796)	(13,573)	(161)	(352)	(543)
4	Total	1,882.9	----	----	----	----	$ (26,427)	$ (77,139)	$ (127,852)	$ (1,057)	$ (3,086)	$ (5,114)

from OMS as of [1/29/2024]

x 5.0 minute average annual reduction

$ 15,427,896.40

C&I - Commercial and Industrial
COI - Cost of Interruption
SAIDI - System Average Interruption Duration Index
Std Deviation - Standard Deviation

Notes

(1) Consumers Energy commercial class assigned to Small C&I and industrial class assigned to Medium / Large C&I
(2) 2024 customer count data based on premises count from OMS system. The model does not take into consideration any changes to customer counts from 2020 to 2024.
(3) Berkeley National Laboratory "Estimated Value of Service Reliability for Electric Utility Customers in the United States", June 2009
(a) Estimates based on 2023 mean costs for 4-hour interruption (Tables 3.2, 4.2, and 5.2) adjusted for inflation
(b) Standard Deviations based on 2021 4-hour interruption (Tables 3.2, 4.2, and 5.2) at 75% confidence level adjusted for inflation
(c) Inflation based on CPI from Bureau of Labor Statistics
(4) Consumers Energy Company Reliability Reports - excluding Major Event Days

	Actual SAIDI
2020	195
2021	228
2022	182
2023	176
2024	170
CAGR (2024 / 2020)	-3.3%

Average annual SAIDI reduction from 2020 to 2024 = -5.0

(5) Average C/(B) to Society = (COI) x (2024 SAIDI x Customers - 2020 SAIDI x Customers)
Minimum C/(B) to Society = (COI - Std Dev) x (2024 SAIDI x Customers - 2020 SAIDI x Customers)
Maximum C/(B) to Society = (COI + Std Dev) x (2024 SAIDI x Customers - 2020 SAIDI x Customers)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21835
Exhibit No.: A-98 (AEM-4)
Page: 1 of 1
Witness: AEMeschke
Date: December 2024

Customer Benefits: Culture Index - Reduced Employee Turnover

December 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
	Annual Employee Turnover					Average
1	Tenure	2020	2021	2022	2023	
2	<1 - 4 years	2.6%	4.4%	4.5%	5.5%	4.3%
3	5+ years	0.6%	1.1%	1.6%	1.5%	1.2%
4	Total Company	1.1%	2.0%	2.5%	2.7%	2.1%
5	Average Turn Over for peer utilities benchmark (2022)					7.3%
6	Average Annual Salary <1-4					$ 95,346
7	Total Employees <1-4					2581
8	2% reduction in turnover for employees with tenure					52
9	<1-4 years					
10	Cost avoidance of 1.5 times average annual salary					$ 7,382,641
11	Cost avoidance of 2.0 times average annual salary					$ 9,843,521

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the Property Tax Rate for the Test Year

Case No.: U-21806
Exhibit No.: A-99 (BJV-1)
Page: 1 of 3
Witness: BJVanBlarcum
Date: December 2024

Line No.	(a) Description	(b) Amount (millions)	(c) Amount (millions)	(d) Amount (millions)	(e) Source
1	Gas Property Taxes Paid - 2025 Estimate			$ 196.8	WP BJV-5, L-4
2	Gas Property Taxes on 2025 Plant Investment			17.2	Ex. A-99 (BJV-1), p.2, L-9
3	Gas Property Taxes on Real Property Taxable Value Increases - Inflation			0.1	Ex. A-99 (BJV-1), p.3, L-4
4	Gas Property Taxes to be Paid - 2026			$ 214.1	
5	2025 Fiscal Year Property Taxes expensed in 2026			98.4	(Line 1 * 50.0%) [1]
6	2026 Property Taxes expensed in 2027			(107.1)	(Line 4 * 50.0%) [1]
7	Gas Property Tax Expense - 2026			$ 205.4	
8	Prorated Gas Property Tax Expense (November - December 2025)			45.9	WP-BJV-5, L-9
9	Prorated Gas Property Tax Expense (January - October 2026)			155.3 [4]	
10	Prorated Gas Property Tax Expense			201.2	(L-8 + L-9)
11	2025 Estimated Year-End Plant-in-Service		$ 14,210.9 [2]		
12	2025 Estimated Construction Work-in-Progress	$ 323.4 [3]			
13	@ 50%	50.00%			
14	2025 Estimated Construction Work-in-Progress		$ 161.7		
15	Estimated Taxable Plant			$14,372.6	(L-11 + L-14)
16	Property Tax Rate			0.013998859	(L-10/L-15)

Footnotes

[1] The 50.0% factor is from the 2023 CE Property Tax Fiscal Year Study

[2] Plant in Service Balance as of 12-31-2025; Plant Model U-21806.xlsx; PIS(WP-HLR-17); Cell AH30

[3] Construction Work in Progress Balance as of 12-31-2025; Plant Model U-21806.xlsx; CWIP(WP-HLR-18); Cell AI30

[4] Development of 2026 Prorated Property Tax Expense

2026 PT Expense	$ 205.4	Ex. A-99 (BJV-1), p.1, L-7
Jan-Oct Expense Ratio	75.61%	Plant Model U-21806.xlsx; Input, Cells B200-K200
Prorated 2025 PT Expense	$ 155.3	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the 2026 Property Taxes
on 2025 Plant Investment

Case No.: U-21806
Exhibit No.: A-99 (BJV-1)
Page: 2 of 3
Witness: BJVanBlarcum
Date: December 2024

Line No.	(a) Description	(b) Amount (millions)		(c) Source
1	**Assessed Value of Personal Property (millions)**			
2	Year-end 2025 Estimated Taxable Closings less Retirements	$ 731.5	[1]	
3	First Year STC Multiplier	94.0%	[2]	
4	**True Cash Value of Personal Property (millions)**	$ 687.6		
5	Statutory Factor for Assessed Value	50%	[3]	
6	New Plant - Assessed Value	$ 343.8		
7	**Estimated Property Tax (millions)**			
8	Estimated Composite Millage Rate	50.1693	[4]	
9	Estimated 2026 Property Taxes Paid	$ 17.2		

Footnotes
[1] 2026 Gas Rate Case Property Tax Model
[2] Michigan Dept of Treasury Form 3589 - 1st year multiplier for Gas Distribution and Transmission Equipment
[3] Article IX, Section 3 of Constitution of Michigan of 1963
[4] CE Composite Millage Rate.xls

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of the 2026 Estimated Gas Portion of
Real Property Taxable Value Increase

Case No.: U-21806
Exhibit No.: A-99 (BJV-1)
Page: 3 of 3
Witness: BJVanBlarcum
Date: December 2024

Line No.	(a) Description	(b) Amount (millions)	(c) Source
1	**2026 Estimated Gas Portion of Real Property Tax Increase (millions)**		
2	2026 Real Property Taxable Value - Estimated Gas Portion	$ 1.0 [1]	
3	2026 Estimated Composite Millage Rate	50.1693 [2]	
4	2026 Estimated Gas Portion of Real Property Taxable Value increase	$ 0.1	

Footnotes
[1] 2026 CE Property Tax Budget
[2] CE Composite Millage Rate.xls

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Amortization of Excess Deferred Federal
Income Taxes for the Test Year

Case No.: U-21806
Exhibit No.: A-100 (BJV-2)
Page: 1 of 3
Witness: BJVanBlarcum
Date: December 2024

Line No.	(a) Description	(b) Projected Regulatory [1] Liability Amortization	(c) Projected Annual [2] Excess Deferred Tax	(d) Proration to Test Year
1	Protected Plant Balance - Subject to ARAM			
2	2025	(10,020,000)	(7,471,724)	(1,245,287)
3	2026	(10,284,000)	(7,668,584)	(6,390,486)
4				
5	**TCJA Amortization - ARAM**			(7,636,000)
6				
7				
8				
9	Non-Protected Plant Balance - 44 years			
10	2025	4,094,000	3,052,818	508,803
11	2026	4,094,000	3,052,818	2,544,015
12				
13				
14	Non-Protected Other Balance - 10 years [3]			
15	2025	-	-	-
16	2026	-	-	-
17				
18	**TCJA Amortization - Non ARAM**			3,053,000
19				
20				
21				
22	**TCJA Regulatory Asset**	3,405,670	2,539,543	2,540,000
23				
24				
25	**Total Test Year Excess Deferred Taxes**			(2,043,000)

[1] Based on the Company's regulatory liability amortization schedule approved in Case No. U-20309.
[2] Adjustment to pre-tax based on 1.341056 gross-up factor used in Case No. U-20309.
[3] The Non-Protected Other Balance was fully refunded to customers as part of the U-20650 settlement agreement.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21806
Exhibit No.: A-100 (BJV-2)
Page: 2 of 3
Witness: BJVanBlarcum
Date: December 2024

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CE Gas
Projected Tax Reform Regulatory Liability & Amortization
($000)

Case No.: U-20309
Exhibit No.: A-6 (SBM-4)
Page: 1 of 1
Witness: SBMcIntosh
Date: April 2019

Line No.	(a) Description	(b) Plant Diff *	(c) Oth Plant Diff ***	(d) All Other	(e) Total Gas
1	Amortization Period	ARAM	44	10	
2					
3	**Tax Reform Regulatory Asset (Liability) After Gross Up**	**$ (552,353)**	**$ 184,295**	**$ (79,356)**	**$ (447,414)**
4					
5	**Amortization Schedule**				
6	**2019	(2,849)	1,023	(1,984)	(3,810)
7	**2020	(9,473)	4,094	(7,936)	(13,315)
8	2021	(9,729)	4,094	(7,936)	(13,571)
9	2022	(9,873)	4,094	(7,936)	(13,715)
10	2023	(9,532)	4,094	(7,936)	(13,374)
11	2024	(9,375)	4,094	(7,936)	(13,217)
12	2025	(10,020)	4,094	(7,936)	(13,862)
13	2026	(10,284)	4,094	(7,936)	(14,126)
14	2027	(9,785)	4,094	(7,936)	(13,627)
15	2028	(9,753)	4,094	(7,936)	(13,594)
16	2029	(10,340)	4,094	(5,952)	(12,198)
17	2030	(10,773)	4,094	-	(6,680)
18	2031	(10,919)	4,094	-	(6,825)
19	2032	(11,389)	4,094	-	(7,295)
20	2033	(11,877)	4,094	-	(7,784)
21	2034	(12,460)	4,094	-	(8,366)
22	2035	(13,242)	4,094	-	(9,148)
23	2036	(14,059)	4,094	-	(9,966)
24	2037	(14,146)	4,094	-	(10,052)
25	2038	(14,240)	4,094	-	(10,146)
26	2039	(14,259)	4,094	-	(10,166)
27	2040	(14,242)	4,094	-	(10,148)
28	2041	(14,257)	4,094	-	(10,163)
29	2042	(14,317)	4,094	-	(10,224)
30	2043	(14,371)	4,094	-	(10,277)
31	2044	(14,355)	4,094	-	(10,261)
32	2045	(14,314)	4,094	-	(10,221)
33	2046	(14,270)	4,094	-	(10,177)
34	2047	(14,252)	4,094	-	(10,158)
35	2048	(14,235)	4,094	-	(10,141)
36	2049 - 2063 ***	(195,362)	64,556	-	(130,806)
37		**$ (552,353)**	**$ 184,295**	**$ (79,356)**	**$ (447,414)**

**** Subject to the normalization provisions of the Internal Revenue Code.***

***** Assumes Deferred Tax Expense adjustment in U-20322 test period.***

****** Includes a $4,174,259 beginning balance adjustment related to AFUDC approved by the Commission in U-21148.***

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21806
Exhibit No.: A-100 (BJV-2)
Page: 3 of 3
Witness: BJVanBlarcum
Date: December 2024

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CE Gas
Tax Reform Regulatory Liability & Amortization

Case No.: U-20309
Date: March 2024

	(1) Beginning Balance	(1-A) Rate Change Gross-up Adjustment [C]	(2) Amount Refunded	(3) Regulatory Asset (Liability)	(2-A) Regulatory Asset/(Liability) Refunded [C]	(3-A) Remaining Regulatory Asset/ (Liability)	(4) Ending Balance
2019	$ (451,588,375)		$ 4,277,605	$ (875,788) [D]	$ 875,788 [D]	$ -	$ (446,434,982)
Beginning Balance Adj [B]	$ 4,174,259		$ -	$ -	$ -	$ -	$ (442,260,723)
2020	$ (442,260,723)		$ 13,315,000	$ (1,352,859) [E]	$ 419,792	$ (933,067)	$ (427,592,864)
2021	$ (427,592,864)		$ 31,207,624	$ (4,671,652) [F]	$ -	$ (4,671,652)	$ (391,713,588)
2022	$ (391,713,588)		$ 49,166,110	$ 3,405,670	$ -	$ 3,405,670	$ (345,953,148)
2023	$ (345,953,148)	$ 529,590	$ 5,438,000	$ 2,002,541	$ -	$ 2,002,541	$ (341,988,099)

[B] In its original U-20309 filing, the Company inadvertently included in its unprotected plant balance a remeasurement of excess deferred taxes associated with AFUDC timing differences. A subsequent reconcilation of the 2019 TCJA balance highlighted this discrepancy. The Company reflected this proposed change in Case No. U-21148 and the Commission subsequently approved the adjustment in it's July 7, 2022 order.

[C] Gross-up change to the regulatory liability balance due to a statutory or apportionment rate change.

[D] Included in Case No. U-21148.

[E] Included in Case No. U-21308.

[F] Included in Case No. U-21490.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Distribution Plant - New Business Program
($000)

Case No.: U-21806
Exhibit No.: A-101 (LDW-2)
Page: 1 of 3
Witness: LDWarriner
Date: December 2024

Line No		(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Year 12 Mos Ending 12/31/2024	(d) Projected Bridge Year 10 Mos Ending 10/31/2025	(e) Projected Bridge Year 22 Mos Ending 10/31/2025	(f) Projected Test Year 12 Mos Ending 10/31/2026
1		**Mains Services & Meter Stands - Dist**	**66,760**	**55,338**	**49,596**	**104,934**	**61,682**
	30%	Labor	19,332	16,726	14,990	31,716	18,643
	27%	Capitalized Engineering/Supv	17,963	15,147	13,575	28,722	16,883
	9%	Material	5,635	5,206	4,666	9,872	5,803
	17%	Contractor	11,199	9,215	8,259	17,475	10,272
	7%	Non-Labor Overheads	5,020	4,048	3,628	7,676	4,512
	9%	Non-Labor Other	7,611	4,996	4,478	9,473	5,569
		Contingency					
2		**Large New Business Projects - Dist**	**9,371**	**9,710**	**3,058**	**12,768**	**4,963**
	10%	Labor	880	944	297	1,241	483
	28%	Capitalized Engineering/Supv	2,643	2,723	858	3,580	1,392
	17%	Material	1,529	1,645	518	2,163	841
	33%	Contractor	3,209	3,238	1,020	4,258	1,655
	1%	Non-Labor Overheads	88	89	28	117	45
	11%	Non-Labor Other	1,022	1,072	338	1,409	548
		Contingency					
3		**Customer Attachment Program - Dist**	**188**	**0**	**0**	**0**	**0**
		Labor	107				
		Capitalized Engineering/Supv	294				
		Material	104				
		Contractor	420				
		Non-Labor Overheads	13				
		Non-Labor Other	(750)				
		Contingency					
4		**Total New Business Capital**	**76,320**	**65,048**	**52,654**	**117,702**	**66,645**
		Labor	20,320	17,670	15,288	32,958	19,126
		Capitalized Engineering/Supv	20,900	17,869	14,433	32,302	18,275
		Material	7,268	6,851	5,184	12,035	6,644
		Contractor	14,828	12,453	9,279	21,732	11,927
		Non-Labor Overheads	5,121	4,137	3,656	7,793	4,557
		Non-Labor Other	7,883	6,067	4,815	10,882	6,116
		Contingency	0	0	0	0	0

This exhibit demonstrates the projected break down for each sub-program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month average (Jan 2023 - Jun 2024) actual percentage of the breakdown of these components in these sub-programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes.

Note: capital “non-labor other” costs include expenses such as pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, non-labor material loadings, contributions/reimbursements and business expenses. WP-LDW-2 page 7 of 7 provides additional details on "non-labor other" costs. Confidence intervals are not used to prepare projections for the above programs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Distribution Plant - New Business Program
($000)

Case No.: U-21806
Exhibit No.: A-101 (LDW-2)
Page: 2 of 3
Witness: LDWarriner
Date: December 2024

		(a)	(b)	(c)	(d)	(e)
			Projected			
			10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
5		**Mains Services & Meter Stands - Dist**	**42,769**	**62,165**	**61,682**	**166,616**
	30%	Labor	12,927	18,789	18,643	50,360
	27%	Capitalized Engineering/Supv	11,706	17,015	16,883	45,605
	9%	Material	4,024	5,848	5,803	15,675
	17%	Contractor	7,122	10,352	10,272	27,746
	7%	Non-Labor Overheads	3,128	4,547	4,512	12,188
	9%	Non-Labor Other	3,861	5,612	5,569	15,042
		Contingency				
6		**Large New Business Projects - Dist**	**7,750**	**5,018**	**4,963**	**17,731**
	10%	Labor	753	488	483	1,724
	28%	Capitalized Engineering/Supv	2,173	1,407	1,392	4,972
	17%	Material	1,313	850	841	3,004
	33%	Contractor	2,584	1,673	1,655	5,913
	1%	Non-Labor Overheads	71	46	45	162
	11%	Non-Labor Other	855	554	548	1,957
		Contingency				
7		**Customer Attachment Program - Dist**	**0**	**0**	**0**	**0**
		Labor				
		Capitalized Engineering/Supv				
		Material				
		Contractor				
		Non-Labor Overheads				
		Non-Labor Other				
		Contingency				
8		**Total New Business Capital**	**50,519**	**67,183**	**66,645**	**184,347**
		Labor	13,680	19,277	19,126	52,084
		Capitalized Engineering/Supv	13,879	18,422	18,275	50,577
		Material	5,336	6,698	6,644	18,679
		Contractor	9,707	12,026	11,927	33,659
		Non-Labor Overheads	3,199	4,593	4,557	12,350
		Non-Labor Other	4,716	6,166	6,116	16,999
		Contingency	0	0	0	0

This exhibit demonstrates the projected break down for each sub-program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month average (Jan 2023 - Jun 2024) actual percentage of the breakdown of these components in these sub-programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes.

Note: capital “non-labor other” costs include expenses such as pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, non-labor material loadings, contributions/reimbursements and business expenses. WP-LDW-2 page 7 of 7 provides additional details on "non-labor other" costs. Confidence intervals are not used to prepare projections for the above programs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Capital Expenditures
Distribution Plant - New Business Program
($000)

Case No.: U-21806
Exhibit No.: A-101 (LDW-2)
Page: 3 of 3
Witness: LDWarriner
Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Year 12 Mos Ending 12/31/2024	(d) Projected Bridge Year 10 Mos Ending 10/31/2025	(e) Projected Bridge Year 22 Mos Ending 10/31/2025 [Col. (c) + (d)]	(f) Projected Test Year 12 Mos Ending 10/31/2026
	Projects Over $5 Million					
1	**Mains Services & Meter Stands - Dist**					
2	None identified	-	-	-	-	-
3	**Large New Business Projects - Dist**					
4	None identified	-	-	-	-	-
5	**Customer Attachment Program - Dist**					
6	None identified	-	-	-	-	-
	Projects Under $5 Million					
7	Mains Services & Meter Stands - Dist	66,760	55,338	49,596	104,934	61,682
8	Large New Business Projects - Dist	9,371	9,710	3,058	12,768	4,963
9	Customer Attachment Program - Dist	188	-	-	-	-
10	**Total New Business Capital**	76,320	65,048	52,654	117,702	66,645

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Distribution Plant - Asset Relocation Program
($000)

Case No.: U-21806
Exhibit No.: A-102 (LDW-3)
Page: 1 of 3
Witness: LDWarriner
Date: December 2024

Line No		Description	Historical Year 12 Mos Ended 12/31/2023	Projected Bridge Year 12 Mos Ending 12/31/2024	Projected Bridge Year 10 Mos Ending 10/31/2025	Projected Bridge Year 22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
	(a)		(b)	(c)	(d)	(e)	(f)
1		**Asset Relocation - Civic Improvement**	**83,518**	**64,148**	**63,612**	**127,760**	**82,162**
	11%	Labor	8,304	6,968	6,910	13,878	8,925
	25%	Capitalized Engineering/Supv	21,295	16,172	16,037	32,210	20,714
	7%	Material	6,428	4,738	4,698	9,436	6,068
	36%	Contractor	30,198	22,862	22,670	45,532	29,281
	2%	Non-Labor Overheads	1,357	1,098	1,089	2,187	1,407
	19%	Non-Labor Other	15,936	12,310	12,207	24,517	15,767
		Contingency					
2		**Asset Relocation - Reimbursable**	**14,167**	**22,690**	**12,226**	**34,916**	**16,647**
	31%	Labor	4,954	7,030	3,788	10,818	5,157
	30%	Capitalized Engineering/Supv	4,272	6,826	3,678	10,504	5,008
	19%	Material	2,302	4,408	2,375	6,783	3,234
	16%	Contractor	1,706	3,731	2,010	5,741	2,737
	7%	Non-Labor Overheads	1,249	1,482	799	2,281	1,088
	-3%	Non-Labor Other	(315)	(787)	(424)	(1,210)	(577)
		Contingency					
3		**Total Distribution Capital**	**97,685**	**86,838**	**75,838**	**162,676**	**98,809**
		Labor	13,258	13,998	10,698	24,696	14,082
		Capitalized Engineering/Supv	25,567	22,998	19,715	42,713	25,722
		Material	8,730	9,146	7,073	16,219	9,302
		Contractor	31,904	26,592	24,681	51,273	32,019
		Non-Labor Overheads	2,606	2,580	1,888	4,468	2,494
		Non-Labor Other	15,621	11,524	11,783	23,307	15,190
		Contingency	0	0	0	0	0

This exhibit demonstrates the projected break down for each sub-program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month average (Jan 2023 - Jun 2024) actual percentage of the breakdown of these components in these sub-programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes.

Note: capital “non-labor other” costs include expenses such as pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, non-labor material loadings, contributions/reimbursements and business expenses. WP-LDW-2 page 7 of 7 provides additional details on "non-labor other" costs. Confidence intervals are not used to prepare projections for the above programs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Distribution Plant - New Business Program
($000)

Case No.: U-21806
Exhibit No.: A-102 (LDW-3)
Page: 2 of 3
Witness: LDWarriner
Date: December 2024

		(a)	(b)	(c)	(d)	(e)
			Projected			
			10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
4		**Asset Relocation - Civic Improvement**	**52,278**	**75,482**	**82,162**	**209,922**
	11%	Labor	5,679	8,199	8,925	22,803
	25%	Capitalized Engineering/Supv	13,180	19,030	20,714	52,923
	7%	Material	3,861	5,575	6,068	15,504
	36%	Contractor	18,631	26,901	29,281	74,813
	2%	Non-Labor Overheads	895	1,292	1,407	3,594
	19%	Non-Labor Other	10,032	14,485	15,767	40,284
		Contingency				
5		**Asset Relocation - Reimbursable**	**20,403**	**14,513**	**16,647**	**51,563**
	31%	Labor	6,321	4,496	5,157	15,975
	30%	Capitalized Engineering/Supv	6,138	4,366	5,008	15,512
	19%	Material	3,964	2,820	3,234	10,017
	16%	Contractor	3,355	2,386	2,737	8,478
	7%	Non-Labor Overheads	1,333	948	1,088	3,368
	-3%	Non-Labor Other	(707)	(503)	(577)	(1,788)
		Contingency				

6		Total Distribution Capital	72,681	89,995	98,809	261,485
		Labor	12,000	12,696	14,082	38,778
		Capitalized Engineering/Supv	19,318	23,396	25,722	68,435
		Material	7,825	8,394	9,302	25,521
		Contractor	21,986	29,287	32,019	83,292
		Non-Labor Overheads	2,228	2,240	2,494	6,962
		Non-Labor Other	9,325	13,982	15,190	38,497
		Contingency	0	0	0	0

This exhibit demonstrates the projected break down for each sub-program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month average (Jan 2023 - Jun 2024) actual percentage of the breakdown of these components in these sub-programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes.

Note: capital “non-labor other” costs include expenses such as pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, non-labor material loadings, contributions/reimbursements and business expenses. WP-LDW-2 page 7 of 7 provides additional details on "non-labor other" costs. Confidence intervals are not used to prepare projections for the above programs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Capital Expenditures
Asset Relocation Program
($000)

Case No.: U-21806
Exhibit No.: A-102 (LDW-3)
Page: 3 of 3
Witness: LDWarriner
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	**Projected Bridge Year**			**Projected Test Year**
Line No	**Description**	**12 Mos Ended 12/31/2023**	**12 Mos Ending 12/31/2024**	**10 Mos Ending 10/31/2025**	**22 Mos Ending 10/31/2025**	**12 Mos Ending 10/31/2026**
					[Col. (c) + (d)]	
	Projects Over $5 Million					
1	**Asset Relocation - Civic Improvement**					
2	None identified	-	-	-	-	-
3	**Asset Relocation - Reimbursable**					
4	None identified	-	-	-	-	-
	Projects Under $5 Million					
5	Asset Relocation - Civic Improvement	83,518	64,148	63,612	127,760	82,162
6	Asset Relocation - Reimbursable	14,167	22,690	12,226	34,916	16,647
7	**Total Capital**	97,685	86,838	75,838	162,676	98,809

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Distribution Plant - Asset Relocation Program
($000)

Case No.: U-21806
Exhibit No.: A-103 (LDW-4)
Page: 1 of 3
Witness: LDWarriner
Date: December 2024

Line No		Description	Historical Year 12 Mos Ended 12/31/2023	Projected Bridge Year 12 Mos Ending 12/31/2024	Projected Bridge Year 10 Mos Ending 10/31/2025	Projected Bridge Year 22 Mos Ending 10/31/2025	Projected Test Year 12 Mos Ending 10/31/2026
		(a)	(b)	(c)	(d)	(e)	(f)
1		**Regulatory Base Distribution**	**39**	**0**	**0**	**0**	**0**
	30%	Labor	11	0	0	0	0
	23%	Capitalized Engineering/Supv	9	0	0	0	0
	2%	Material	2	0	0	0	0
	3%	Contractor	2	0	0	0	0
	22%	Non-Labor Overheads	6	0	0	0	0
	20%	Non-Labor Other Contingency	9	0	0	0	0
2		**Meters**	**20,450**	**24,909**	**23,457**	**48,366**	**24,700**
	20%	Labor	4,042	4,937	4,650	9,587	4,896
	24%	Capitalized Engineering/Supv	4,982	6,023	5,672	11,695	5,973
	44%	Material	8,934	10,956	10,317	21,274	10,864
	0%	Contractor	3	2	2	5	2
	0%	Non-Labor Overheads	0	0	0	0	0
	12%	Non-Labor Other Contingency	2,490	2,990	2,816	5,806	2,965
3		**MAOP Distribution**	**1,607**	**9,295**	**59,964**	**69,259**	**115,812**
	9%	Labor	100	801	5,166	5,967	9,978
	24%	Capitalized Engineering/Supv	384	2,190	14,127	16,317	27,285
	11%	Material		1,014	6,539	7,553	12,629
	36%	Contractor	833	3,368	21,726	25,094	41,961
	1%	Non-Labor Overheads		50	320	370	619
	20%	Non-Labor Other Contingency	289	1,873	12,085	13,958	23,340
4		**Cathodic - Distribution**	**12,392**	**11,013**	**8,282**	**19,296**	**9,800**
	14%	Labor	1,897	1,594	1,199	2,792	1,418
	25%	Capitalized Engineering/Supv	3,070	2,713	2,041	4,754	2,415
	25%	Material	2,752	2,738	2,059	4,797	2,437
	16%	Contractor	2,064	1,802	1,355	3,156	1,603
	3%	Non-Labor Overheads	404	297	224	521	265
	17%	Non-Labor Other Contingency	2,205	1,869	1,405	3,274	1,663
5		Total Distribution Capital	34,488	45,217	91,704	136,920	150,311
		Labor	6,051	7,332	11,015	18,347	16,292
		Capitalized Engineering/Supv	8,445	10,926	21,840	32,766	35,672
		Material	11,687	14,708	18,916	33,624	25,930
		Contractor	2,902	5,172	23,083	28,255	43,567
		Non-Labor Overheads	410	347	544	891	883
		Non-Labor Other Contingency	4,992	6,732	16,306	23,038	27,968

This exhibit demonstrates the projected break down for each sub-program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month average (Jan 2023 - Jun 2024) actual percentage of the breakdown of these components in these sub-programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes.

Note: capital “non-labor other” costs include expenses such as pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, non-labor material loadings, contributions/reimbursements and business expenses. WP-LDW-2 page 7 of 7 provides additional details on "non-labor other" costs. Confidence intervals are not used to prepare projections for the above programs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual and Projected Capital Expenditures
Distribution Plant - New Business Program
($000)

Case No.: U-21806
Exhibit No.: A-103 (LDW-4)
Page: 2 of 3
Witness: LDWarriner
Date: December 2024

		(a)	(b)	(c)	(d)	(e)
			Projected			
			10 Mos Ending 10/31/2024	12 Mos Ending 10/31/2025	12 Mos Ending 10/31/2026	34 Mos Ending 10/31/2026
6		**Regulatory Base Distribution**	**41**	**(41)**	**-**	**(0)**
	30%	Labor	12	(12)	0	(0)
	23%	Capitalized Engineering/Supv	9	(9)	0	(0)
	2%	Material	1	(1)	0	(0)
	3%	Contractor	1	(1)	0	(0)
	22%	Non-Labor Overheads	9	(9)	0	(0)
	20%	Non-Labor Other	8	(8)	0	(0)
		Contingency				
7		**Meters**	21,249	27,117	24,700	73,066
	20%	Labor	4,212	5,375	4,896	14,483
	24%	Capitalized Engineering/Supv	5,138	6,557	5,973	17,668
	44%	Material	9,346	11,927	10,864	32,138
	0%	Contractor	2	3	2	7
	0%	Non-Labor Overheads	0	0	0	0
	12%	Non-Labor Other	2,551	3,255	2,965	8,770
		Contingency				
8		**MAOP Distribution**	5,212	64,047	115,812	185,070
	9%	Labor	449	5,518	9,978	15,945
	24%	Capitalized Engineering/Supv	1,228	15,089	27,285	43,602
	11%	Material	568	6,984	12,629	20,182
	36%	Contractor	1,888	23,206	41,961	67,055
	1%	Non-Labor Overheads	28	342	619	988
	20%	Non-Labor Other	1,050	12,907	23,340	37,298
		Contingency				
9		**Cathodic - Distribution**	10,372	8,924	9,800	29,096
	14%	Labor	1,501	1,291	1,418	4,211
	25%	Capitalized Engineering/Supv	2,555	2,199	2,415	7,169
	25%	Material	2,579	2,219	2,437	7,234
	16%	Contractor	1,697	1,460	1,603	4,759
	3%	Non-Labor Overheads	280	241	265	785
	17%	Non-Labor Other	1,760	1,514	1,663	4,937
		Contingency				
10		Total Distribution Capital	36,873	100,047	150,311	287,232
		Labor	6,174	12,173	16,292	34,639
		Capitalized Engineering/Supv	8,931	23,835	35,672	68,438
		Material	12,494	21,129	25,930	59,553
		Contractor	3,588	24,667	43,567	71,822
		Non-Labor Overheads	317	574	883	1,774
		Non-Labor Other	5,369	17,669	27,968	51,006
		Contingency	0	0	0	0

This exhibit demonstrates the projected break down for each sub-program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month average (Jan 2023 - Jun 2024) actual percentage of the breakdown of these components in these sub-programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes.

Note: capital “non-labor other” costs include expenses such as pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, non-labor material loadings, contributions/reimbursements and business expenses. WP-LDW-2 page 7 of 7 provides additional details on "non-labor other" costs. Confidence intervals are not used to prepare projections for the above programs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Capital Expenditures
Regulatory Compliance Program
($000)

Case No.: U-21806
Exhibit No.: A-103 (LDW-4)
Page: 3 of 3
Witness: LDWarriner
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	**Projected Bridge Year**			**Projected Test Year**
Line No	**Description**	**12 Mos Ended 12/31/2023**	**12 Mos Ending 12/31/2024**	**10 Mos Ending 10/31/2025**	**22 Mos Ending 10/31/2025**	**12 Mos Ending 10/31/2026**
					[Col. (c) + (d)]	
	Projects Over $5 Million					
1	**Regulatory Base Distribution**					
2	None identified	-	-	-	-	-
3	**Meters**					
4	None identified	-	-	-	-	-
5	**MAOP Distribution**					
6	Line 1009-1009c Phase 3	-	-	-	-	8,037
7	Line 1022 Phase 1 & Phase 2	41	87	-	87	33,151
8	Line 1026f			-	-	9,024
9	Line 1006 Phase 1		81	-	81	5,179
10	Line 1009-1009c Phase 2			12,213	12,213	7,722
11	Line 1087b Phase 1		505	3,238	3,743	2,047
12	Line 1093			-	-	17,417
13	Line 1080	363	3,829	29,945	33,774	561
14	Line 1002c	934	688	9,452	10,140	39,362
15	**Cathodic - Distribution**					
16	None identified	-	-	-	-	-
	Projects Under $5 Million					
17	Regulatory Base Distribution	39	-	-	-	-
18	Meters	20,450	24,909	23,457	48,366	24,700
19	MAOP Distribution	269	4,106	5,116	9,222	(6,688)
20	Cathodic - Distribution	12,392	11,013	8,282	19,296	9,800
21	**Total Capital**	34,488	45,217	91,704	136,920	150,311

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Transmission and Distribution Capital Expenditures
Capacity/Deliverability Program
Summary of Actual & Projected Gas and Common Capital Expenditures

Case No.: U-21806
Exhibit No.: A-104 (LDW-5)
Page: 1 of 2
Witness: LDWarriner
Date: December 2024

Line No		Description	(a) Historical Year 12 Mos Ended 12/31/2023	(b) Projected Bridge Year 12 Mos Ending 12/31/2024	(c) Projected Bridge Year 10 Mos Ending 10/31/2025	(d) Projected Bridge Year 22 Mos Ending 10/31/2025	(e) Projected Test Year 12 Mos Ending 10/31/2026
1		**Augment**	**4,446**	**7,493**	**7,019**	**14,512**	**5,354**
	9%	Labor	430	677	635	1,312	484
	25%	Capitalized Engineering/Supv	1,096	1,849	1,732	3,581	1,321
	12%	Materials	563	884	829	1,713	632
	35%	Contractor	1,495	2,644	2,477	5,120	1,889
	1%	Non-Labor Overhead	65	88	82	170	63
	18%	Non-Labor Other	796	1,351	1,265	2,616	965
2		**Total Capital**	**4,446**	**7,493**	**7,019**	**14,512**	**5,354**
		Labor	430	677	635	1,312	484
		Capitalized Engineering/Supv	1,096	1,849	1,732	3,581	1,321
		Materials	563	884	829	1,713	632
		Contractor	1,495	2,644	2,477	5,120	1,889
		Non-Labor Overhead	65	88	82	170	63
		Non-Labor Other	796	1,351	1,265	2,616	965

Line No		Description	Projected 10 Mos Ending 10/31/2024	Projected 12 Mos Ending 10/31/2025	Projected 12 Mos Ending 10/31/2026	Projected 34 Mos Ending 10/31/2026
3		**Augment**	**5,042**	**9,470**	**5,354**	**19,867**
	9%	Labor	456	856	484	1,796
	25%	Capitalized Engineering/Supv	1,244	2,337	1,321	4,903
	12%	Materials	595	1,118	632	2,345
	35%	Contractor	1,779	3,341	1,889	7,009
	1%	Non-Labor Overhead	59	111	63	233
	18%	Non-Labor Other	909	1,707	965	3,581
4		Total Capital	5,042	9,470	5,354	19,867
		Labor	456	856	484	1,796
		Capitalized Engineering/Supv	1,244	2,337	1,321	4,903
		Materials	595	1,118	632	2,345
		Contractor	1,779	3,341	1,889	7,009
		Non-Labor Overhead	59	111	63	233
		Non-Labor Other	909	1,707	965	3,581

This exhibit demonstrates the projected break down for each sub-program into the cost components shown above. The 2023 amounts are the actual amounts. The cost component projections for 2024 and beyond are based upon the 2023-2024 18 month average (Jan 2023 - Jun 2024) actual percentage of the breakdown of these components in these sub-programs. The Company projects the program expenditures at a total dollar level based upon historical spending and known projects or other changes.

Note: capital “non-labor other” costs include expenses such as pension, administrative/general expenses, indirect non-labor expenses, rent/utility costs, employee benefits, non-labor material loadings, contributions/reimbursements and business expenses. WP-LDW-2 page 7 of 7 provides additional details on "non-labor other" costs. Confidence intervals are not used to prepare projections for the above programs.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Actual & Projected Gas Transmission and Distribution Capital Expenditures
Capacity/Deliverability Program
Summary of Actual & Projected Gas and Common Capital Expenditures

Case No.: U-21806
Exhibit No.: A-104 (LDW-5)
Page: 2 of 2
Witness: LDWarriner
Date: December 2024

Line No	(a) Description	(b) Historical Year 12 Mos Ended 12/31/2023	(c) Projected Bridge Year 12 Mos Ending 12/31/2024	(d) Projected Bridge Year 10 Mos Ending 10/31/2025	(e) Projected Bridge Year 22 Mos Ending 10/31/2025 [Col. (c) + (d)]	(f) Projected Test Year 12 Mos Ending 10/31/2026
	Projects Over $5 Million					
1	**Augment**					
2	None identified	-	-	-	-	-
	Projects Under $5 Million					
3	Augment	4,446	7,493	7,019	14,512	5,354
4	**Total Capital**	4,446	7,493	7,019	14,512	5,354

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures
Transmission & Distribution Plant
Summary of Actual & Projected Gas Capital Expenditures
($000)

Case No.: U-21806
Exhibit No.: A-105 (LDW-6)
Page: 1 of 1
Witness: LDWarriner
Date: December 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Capital Expenditures					
Line No.	Program Description	Historic Test Year 2023 Actual	Last Rate Case Approved Spending Plan Case No. U-21490 12 mos. Ending 9/30/2025 [1]	Last Rate Case Actual Spending Case No. U-21490 12 mos. Ending 9/30/2025 [2]	Variation Percentage [1]	Location of Testimony Regarding Significant Var [1] (>10%)	Current Case Projection 12 mos. Ending 10/31/2026
1	New Business	76,320	n/a	n/a	n/a	n/a	66,645
2	Asset Relocation	97,685	n/a	n/a	n/a	n/a	98,809
3	Regulatory Compliance	34,488	n/a	n/a	n/a	n/a	150,311
3	Capacity/Deliverability	4,446	n/a	n/a	n/a	n/a	5,354
4	**Total Capital**	212,938	-	-			321,119

Footnote:

[1] Case No. U-21490 resulted in a settlement agreement that did not state approved capital spending amounts for the programs represented here
[2] The projected test year in Case No. U-21490 has not transpired as of the date of this filing

Global Research and Evidence Lab
10 May 2023

US Utilities

Pricing Power Analysis and Regulatory Rankings

Equities

Americas

Utilities

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Updated Regulatory Rankings

We have updated the regulatory rankings of the 58 jurisdictions in North America across five Tiers (Tier 1 is most constructive, Tier 5 is least constructive). See Figure 3. We rate the jurisdictions using seven criteria. We believe constructive regulation provides a positive feedback loop of consistent and fair outcomes for investors, that also results in better customer service and satisfaction, which is what regulators want to see to constructively regulate. Jurisdictions that moved up are AL, ID, and PA (to Tier 1 from Tier 2), CA, MO, and ND (to Tier 2 from Tier 3), and NY (to Tier 4 from Tier 5). We would also note that while LA remained in Tier 3 it moved up significantly from the bottom to the top of that Tier. Jurisdictions that moved down are IN and MI (to Tier 2 from Tier 1), AK (to Tier 4 from Tier 3), and DC, MS, and NM (to Tier 5 from Tier 4).

Lower Relative Pricing Power a Risk to Regulation and Growth

Our pricing power analysis tends to point to where regulatory strain or growth pressures may develop. We saw this last year when our metric showed lower relative pricing power for EXC, PEG, NI, EMA, D, PCG, WEC, and NEE. Most either lowered or rebased their growth - EXC, PEG, and NI; or, faced material regulatory headwinds - EMA and the rate cap legislation in NS, and D with the overall strategic review and legislation in VA reworking the regulatory construct. For WEC, although the rate case outcome was constructive in WI, the rhetoric during the hearing was not encouraging. Where pricing power did not pressure regulation or earnings growth was for NEE and PCG. We rank FL as the most constructive regulatory jurisdiction in North America and NEE's rates at FPL are set through 2025. We also believe CA regulation is increasingly constructive around wildfire and clean energy policy goals, as evidenced by the move to Tier 2 in this year's jurisdiction rankings. Companies that show lower relative pricing power in our updated analysis that did not in May 2022 are AES, CMS, CNP, DTE, ED, ES, and EVRG. Of these names we are Buy rated on AES mainly for the unregulated story, and CNP, where we think significant customer growth in TX can help alleviate pricing pressures. We are Neutral on the remaining names with lower pricing power in '23 vs. '22 and remain diligent in watching regulatory processes in MI for CMS and DTE, in CT for ES, and in KS for EVRG as well as policy in NY for ED. Names that showed continued lower relative pricing power in '23 vs. '22 are D, EXC, NI, PEG, and WEC where D, EXC, NI, and PEG have either gone into or completed a strategic review and/or lowered/rebased their growth rates. WEC remains in a Tier 1 regulatory jurisdiction in WI, but the LNT rate case in that state, as well as WEC's gas case in IL are worth watching.

Updated Pricing Power Analysis - Affordability Inflation vs. Growth

Our analysis places the group across one of four quadrants, although a little more than half of companies are clustered around the combined medians (see Figure 1). We have overlayed the weighted average regulatory ranking quartile of each company on this matrix indicated by color as noted. Those companies outside the median zone in one of the four quadrants are: (I) Pricing power with lower costs or higher weighted average disposable income growth: PCG, PPL, and SO; (II) Lower pricing power, requiring constructive regulation to maintain growth: AES, CMS, CNP, EXC, ES and NI; (III) Lower pricing power that would require constructive regulation or policy support to accelerate growth: D, DTE, ED, EVRG, PEG, and WEC; (IV) Pricing power and opportunity to accelerate growth if regulation is constructive: EIX, OGE, and PNW.

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ANALYSIS OF PRICING POWER IN REGULATED UTILITIES

Given investor focus on inflation and its potential impacts, and the potential for accelerating capital expenditures and rate base growth into the clean energy transition (Cap-Ex Update: Breakthroughs in Spending, 30 March 2023) we analyzed the "pricing power" of regulated utilities. Instead of just a straight analysis of annual increases in bills, we took the estimated bill increase divided by the weighted average personal income by jurisdiction for each company. We then estimated the total increase in that metric through 2029 and annualized that number. We believe this is a more accurate representation of "pricing power" for a utility as it takes into account the relative affordability of the projected bill increases across the relative incomes of the customer base across a company's jurisdictions.

To calculate bill inflation, we used each company's projected capital plan and extended that at flat capex to 2029 from the end of each company's forecast to determine rate base growth. For fuel expenses, we used forward curves and retired all coal generation by 2028 and replaced it with a third each of solar, wind, and natural gas. We incorporated non-fuel O&M increases of 2%/year, held interest expense at 5.5%, used 30-year depreciation, and an allowed return of 10.2% and a 48% equity ratio. While individual companies may achieve better or worse metrics, we tried to create an average metric across companies over the eight-year time frame. Retail sales growth averaged approximately 1% per year.

To calculate disposable income, we took each state or province's disposable income in 2021 and grew it by forecast gross state or provincial product through 2025 and then held annual gross state or provincial product growth constant through 2029. For each company we weighted this by earnings power by jurisdiction to estimate the weighted average disposable income.

Dividing annual bills by weighted average disposable income projected into 2029 and seeing how much that grew versus the same metric in 2021, and annualizing that growth provides a measure of bill affordability inflation. When we graph this against annualized projected utility and parent only EPS growth, the results are shown in Figure 1 below. We have also overlayed the weighted average regulatory ranking quartile onto this graph through the color of the dots: 1st quartile is green, 2nd quartile is blue, 3rd quartile is yellow, and 4th quartile is red. This relative regulatory quartile is important, as more constructive regulation will likely allow for more EPS growth with more affordability inflation, all else equal.

In Figure 1, about half of the companies end up around the median level of growth and affordability inflation of ~6.3% and just under 1%, respectively. Those outside of the median grouping end up in one of four quadrants: (I) high growth and low affordability inflation - where there is clear pricing power due to lower cost structures or higher disposable income growth; (II) high growth and higher affordability inflation, where pricing power needs to be maintained by constructive regulation or policy support to maintain growth; (III) lower growth and higher affordability inflation - where there is lower relative pricing power and it would require constructive regulation or, more likely a state or provincial energy policy initiative to accelerate growth above the median, and (IV) low growth and low affordability inflation - where there is an opportunity to accelerate growth if regulation is constructive or where a company might get stuck at lower than median growth if regulation is more challenging.

Our pricing power analysis tends to point to where regulatory strain or growth pressures may develop as we saw last year when our metric showed lower relative pricing power for EXC, PEG, NI, EMA, D, PCG, WEC, and NEE. Most either lowered or rebased their growth - EXC, PEG, and NI or faced material regulatory headwinds - EMA and the rate cap legislation in NS; D with the overall strategic review and legislation in VA reworking the regulatory construct. For WEC although the rate case outcome was constructive in WI the rhetoric during the hearing was not encouraging. Where pricing power did not pressure regulation or earnings growth was for NEE and PCG. We rank FL as the most constructive regulatory jurisdiction in North America and NEE's rates at FPL are set through 2025. We also believe CA regulation is increasingly supportive around wildfire and clean energy policy goals, as evidenced by the move to Tier 2 in this year's jurisdiction rankings. Companies that show lower relative pricing power in our updated

analysis that did not in May 2022 are AES, CMS, CNP, DTE, ED, ES, and EVRG. Of these names we are Buy rated on AES mainly for the unregulated story, and CNP, where we think significant customer growth in TX can help alleviate pricing pressures. We are Neutral on the remaining names with lower pricing power in '23 vs. '22 and remain diligent in watching regulatory processes in MI for CMS and DTE, in CT for ES, and in KS for EVRG as well as policy in NY for ED. Names that showed continued lower relative pricing power in '23 vs. '22 are D, EXC, NI, PEG, and WEC where D, EXC, NI, and PEG have either gone into or completed a strategic review and/or lowered/rebased their growth rates. WEC remains in a Tier 1 regulatory jurisdiction in WI, but the LNT rate case in that state, as well as WEC's gas case in IL are worth watching.

Figure 1: EPS Growth vs. Affordability Inflation May 2023

Source: Company filings, FactSet, S&P Global Market Intelligence, UBS Equity Research estimates

NOTES:

Wtd. Avg. Regulatory Rank in indicated by color. Green is 1st quartile, Blue is 2nd quartile, Yellow is 3rd quartile, and Red is 4th quartile.

Bill inflation is calculated as the increase in annual bills/disposable income, annualized. Disposable income is grown at state forecast GDP, and a weighted average is taken by company.

Figure 2: EPS Growth vs. Affordability Inflation May 2022

Source: Company filings, FactSet, S&P Global Market Intelligence, UBS Equity Research estimates

NOTES:

Wtd. Avg. Regulatory Rank in indicated by color. Green is 1st quartile, Blue is 2nd quartile, Yellow is 3rd quartile, and Red is 4th quartile.

Bill inflation is calculated as the increase in annual bills/disposable income, annualized. Disposable income is grown at state forecast GDP, and a weighted average is taken by company.

UPDATED REGULATORY RANKINGS

We are updating our jurisdictional regulatory rankings which we do approximately every 6 months. Our last update was in November 2022 Shifting Reguatory and Growth Quartiles.

We rate the jurisdictions using seven criteria. We believe that constructive regulation provides a positive feedback loop of consistent and fair outcomes for investors, that also results in better customer service and satisfaction, which is what regulators want to see to constructively regulate. At the bottom of Figure 3 we show the average JD Power Customer Service scores, which are mostly consistent with our tiered rankings. Those jurisdictions highlighted in green moved up, and those highlighted in red moved down versus our previous rankings. As a reminder the table reads as an ranking histogram so Florida in Tier 1 is more constructive than British Columbia in Tier 1, and so on.

Figure 3: UBS North America Jurisdictional Regulatory Rankings

UBS REGULATORY JURISDICTION RANKINGS - May 2023 Update

TIER 1	TIER 2	TIER 3	TIER 4	TIER 5
		New Jersey		
		Louisiana		
		Massachusetts		
		Oregon		
		South Carolina		
		Tennessee		
	Arkansas	Washington		
Florida	Indiana	Newfoundland & Labrador	Rhode Island	Alberta
British Columbia	Kentucky	Ontario	Nova Scotia	District of Columbia
North Carolina	Michigan	Virginia	West Virginia	Mississippi
Utah	California	Wyoming	Alaska	New Mexico
Wisconsin	FERC	Ohio	Kansas	Connecticut
Iowa	Missouri	Oklahoma	Minnesota	Maine
Alabama	North Dakota	Texas	Nevada	Montana
Georgia	Colorado	Maryland	New Hampshire	South Dakota
Idaho	Delaware	Prince Edward Island	Nebraska	Vermont
Pennsylvania	Illinois	Hawaii	New York	Arizona
JD Power Average Customer Service Scores				
751	718	727	717	719

Source: S&P Capital IQ Pro, FactSet, JD Power, UBS Equity Research

NOTES: Green indicates moved up a Tier since last rankings, Red indicates moved down a Tier. LA is highlighted given it moved significantly within Tier 3 since the last rankings

The ranking criteria are as follows:

1) Elected vs. Appointed Commissions: Elected commissioners tend to focus more closely on managing customer affordability which can dampen investment vs. appointed commissions that tend to be more policy driven, all else equal.

2) Tendency to Settle vs. Litigate Rate Cases: Settlements have the advantage of being quicker, less risky and less prone to legal appeal than fully litigated rate proceedings. States that regularly settle are preferred by investors.

3) Regulatory Lag: Regulatory lag is the difference between authorized returns on equity and earned returns resulting from time lag between dollars invested in rate base and authorized revenues reflecting that spending. We rank regulatory lag based on the time it takes to reach a decision in rate cases.

4) Rate and Customer Bill Levels: Utilities' prices are often a material factor in state economic development. States with high prices versus their surroundings tend to scrutinize utility investment more closely than states with low bills. We look at the average rate and the average residential bill.

5) Allowed Return Spread: We measure the return spread over 10-year Treasury note of the ordered rate cases since 2010 by jurisdiction. As rate of return setting policies and practices are grounded in decades of case law, jurisdictions that allow high and low return spreads tend to continue with that practice.

6) Regulatory Mechanisms: We include an average of eight mechanisms. These include things like tracking mechanisms, forward test years, formula rate plans, and performance based regulation.

7) UBS Subjective Investor Friendliness Factor: Based on our knowledge of current commission actions.

Biggest Changes to the State Rankings

With this review we highlight the largest positive and negative ranking votes out of 58 total jurisdictions we are covering in the United States and Canada:

Positive Changes

- Alabama. Constructive tracking mechanisms, high ROE spreads, and lower relative rates moved the state into Tier 1 relative to other jurisdictions.
- Idaho. Continued low rates moved the jurisdiction into Tier 1 relative to other jurisdictions.
- Pennsylvania. Relative improvement given other states fell to Tier 2.
- California. Regulatory lag improved from 5th quintile to 4th which moved the state from the top of Tier 3 in our May 2022 analysis into Tier 2.
- Missouri. Regulatory lag improved from 3rd quintile to 2nd, moving the state to Tier 2 from near the top of Tier 3 in our prior analysis.
- North Dakota. Settlements became more common, and historical ROE spread improved to 2nd quintile from 3rd quintile, offset slightly by regulatory lag increasing, moving to the 4th quintile from the 3rd.
- Louisiana. Did not move out of Tier 3, however did have a significant move worth highlighting from the bottom to the top of that Tier. ROE spread to the 10 year improved and it moved to 2nd quintile from 4th in that category.
- New York. Settle vs. Litigate improved to 1st quintile from the 2nd.

Negative Changes

- Indiana. Cost to customers got a bit worse with a move to the 3rd quintile from the 2nd which was enough to move the state to Tier 2 from the bottom of Tier 1 in May 2022.
- Michigan. ROE spread to the 10 year came in to 3rd quintile from 2nd, and we moved our subjectiveness ranking to 2nd quintile vs. 1st quintile.
- Alaska. Moved lower as other states moved higher so lost relative positioning into Tier 3
- District of Columbia. Lower rate of settlements, 5th quintile ROE spreads, and 4th quintile regulatory lag pushed this jurisdiction to the top of Tier 5 relative to other jurisdictions from the bottom of Tier 4 in May 2022.
- Mississippi. Elected commission with higher relative costs to customers average regulatory lag, and 5th quintile ROE spreads versus risk free rates, pushed this state into Tier 5 relative to other jurisdictions.
- New Mexico. Was at the bottom of Tier 4 in our May 2022 analysis and was a relative mover to Tier 5 as New York improved into Tier 4.

Valuation Method and Risk Statement

North America Utilities: Our valuation methodology for the group is price to earnings based. The adjustments applied fall into 7 categories. These are as follows: 1) Group Valuation Bias: Flowing from our valuation work comparing Baa corporate yields to group dividend yields and RU price to earnings ratios to those for the S&P 500, we incorporate a positive or negative adjustment to our group multiple representing the gap we calculate to the nearest 5%; 2) Growth Adjustment: We adjust our valuations based on the growth quartile each utility occupies. First quartile receives a 4% premium, second quartile a 2% premium, third quartile a 2% discount and fourth quartile a 4% discount; 3) Regulatory Adjustment: Our valuation adjustments for regulation are based on our proprietary Regulatory Rankings. First quartile jurisdictions receive 10%, second quartile 5%, third quartile -5% and fourth quartile -10%; 4) Clean Energy Transition: A potential 5% premium for a risk adjusted clean energy transition growth opportunity; 5) Earnings Consistency Adjustment: For companies that fall in the top quartile of % Time Beat/Meet, we include +4%; 6) Multi Utility Diversified Valuation: For multi utilities (those with more than 15% of unregulated earnings), we perform a sum-of-the-parts analysis applying business/region appropriate valuations to those diversified businesses; 7) One-off Adjustments: In special situations, we value risk on an issue-specific basis. Common areas where we apply such an adjustment include: large project construction risk, legal risk, and announced M&A completion risk. We identify the following risk factors: rising interest rates; regulatory and policy risks; operational risks; construction risks; cybersecurity risk to the transmission grid and/or customer data, and extreme weather events.

IPPs: Our valuation methodology is based on mid-cycle EV/EBITDA multiples of 7.1x.

CEG: Our valuation methodology is based on an infrastructure comp on EV/EBITDA.

Water Utilities: Our valuation methodology for the group is price-to-earnings based. Our methodology includes: 1) Growth Adjustment: We adjust our valuations based on the growth quartile each utility occupies. First quartile receives a 4% premium, second quartile a 2% premium, third quartile a 2% discount and fourth quartile a 4% discount; and 2) Regulatory Adjustment: Our valuation adjustments for regulation are based on our proprietary Regulatory Rankings. First quartile jurisdictions receive 10%, second quartile 5%, third quartile -5% and fourth quartile -10%.

North American utilities: We identify the following risk factors for the sector overall: rising interest rates; regulatory and policy risks; operational risks; construction risks; cybersecurity risk to the transmission grid and/or customer data, and extreme weather events.

IPPs: We identify the following risks for the sector: Power prices, fuel prices, capacity prices, supply and demand for electricity, extreme weather, economic conditions, and cost of financing and collateral hedging.

CEG: We identify the following risks for CEG: Power price volatility above the nuclear PTC price, uranium fuel prices, supply and demand for electricity, cost of financing and nuclear operational risk.

Water Utilities: We identify the following risks: rising interest rate; regulatory and policy risks; operational risks; construction risks; water quality, safety and contamination risk; physical risk to the water sources, treatment or delivery systems; cybersecurity risk; drought and extreme weather events.

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Buy	FSR is > 6% above the MRA.	54%	22%
Neutral	FSR is between -6% and 6% of the MRA.	36%	21%
Sell	FSR is > 6% below the MRA.	10%	18%
Short-Term Rating	**Definition**	**Coverage[3]**	**IB Services[4]**
Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%
Sell	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%

Source: UBS. Rating allocations are as of 31 March 2023.
1:Percentage of companies under coverage globally within the 12-month rating category.
2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
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UBS Securities LLC: Gregg Orrill, Ross Fowler, CFA, William Appicelli, CFA.

Company Disclosures

Company Name	Reuters	12-month rating	Price	Price date
AES Corp[16]	AES.N	Buy	US$21.71	08 May 2023
Alliant Energy Corp[16]	LNT.O	Neutral	US$54.76	08 May 2023
Ameren Corp[16]	AEE.N	Neutral	US$89.14	08 May 2023
American Electric Power Inc[16,7,6b]	AEP.O	Buy	US$92.14	08 May 2023
CMS Energy Corp[16]	CMS.N	Neutral	US$61.19	08 May 2023
CenterPoint Energy Inc[16]	CNP.N	Buy	US$30.25	08 May 2023
Consolidated Edison Inc[16]	ED.N	Neutral	US$99.01	08 May 2023
DTE Energy Co[16]	DTE.N	Neutral	US$113.00	08 May 2023
Dominion Energy Inc[16,7,6b]	D.N	Neutral	US$56.50	08 May 2023
Duke Energy Corp[16,7,6b,6c]	DUK.N	Neutral	US$98.90	08 May 2023
Edison International[16]	EIX.N	Buy	US$73.39	08 May 2023
Emera Inc	EMA.TO	Buy	C$58.95	08 May 2023
Entergy Corp[16,7,6b,6c]	ETR.N	Neutral	US$106.91	08 May 2023
Evergy, Inc[16]	EVRG.O	Neutral	US$62.05	08 May 2023
Eversource Energy[16,7,6b]	ES.N	Neutral	US$76.75	08 May 2023
Exelon Corp[16,7,6b,6c]	EXC.O	Buy	US$42.77	08 May 2023
FirstEnergy Corp[16]	FE.N	Buy	US$39.09	08 May 2023
Fortis Inc[16]	FTS.TO	Sell	C$61.27	08 May 2023
NextEra Energy Inc[2,4,5,16,7,6a]	NEE.N	Buy	US$76.06	08 May 2023
NiSource Inc.[16]	NI.N	Neutral	US$28.45	08 May 2023
OGE Energy Corp[16]	OGE.N	Neutral	US$37.55	08 May 2023
PG&E Corp[16,7,6b,6c]	PCG.N	Neutral	US$17.41	08 May 2023
PPL Corp[16]	PPL.N	Buy	US$28.59	08 May 2023
Pinnacle West Capital Corp[16,7,6b]	PNW.N	Sell	US$79.82	08 May 2023
Public Service Enterprise Group[16,7,6b]	PEG.N	Buy	US$63.49	08 May 2023
Sempra[16]	SRE.N	Buy	US$154.93	08 May 2023
Southern Co[13,16]	SO.N	Buy	US$74.57	08 May 2023

Company Name	Reuters	12-month rating	Price	Price date
WEC Energy Group Inc[16]	WEC.N	Neutral	US$95.03	08 May 2023
Xcel Energy Inc[16]	XEL.O	Neutral	US$69.32	08 May 2023

Source: UBS. All prices as of local market close. Ratings in this table are the most current published ratings prior to this report. They may be more recent than the stock pricing date.

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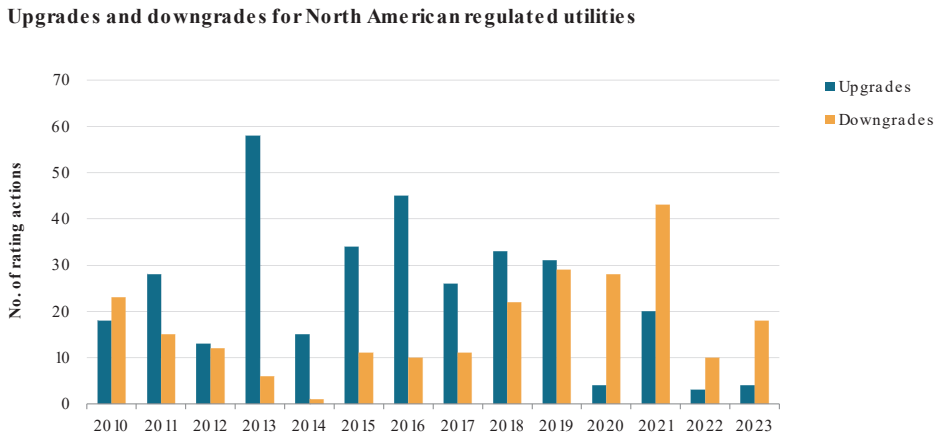
Key Takeaways

- We are updating our 2024 outlook on the investor-owned North American regulated utility industry to negative.
- Given the relatively high percentage of companies with negative outlooks, we expect that 2024 will likely be the fifth consecutive year that downgrades outpace upgrades.
- The industry faces rising physical risks and high cash flow deficits that may not be sufficiently funded in a credit-supportive manner.
- Still, we expect that the utility industry will maintain a median investment-grade rating of 'BBB+'.
- We also expect that a smaller percentage of companies rated 'BBB' or lower are more likely to implement measures to maintain or even improve credit quality.

Credit quality for North American investor-owned regulated utilities has weakened over the past four years, with downgrades outpacing upgrades by more than three times. We expect downgrades to again surpass upgrades in 2024 for the fifth consecutive year. In the decade prior to 2020, upgrades generally outpaced downgrades in the industry.

Chart 1



Source: S&P Global Ratings.

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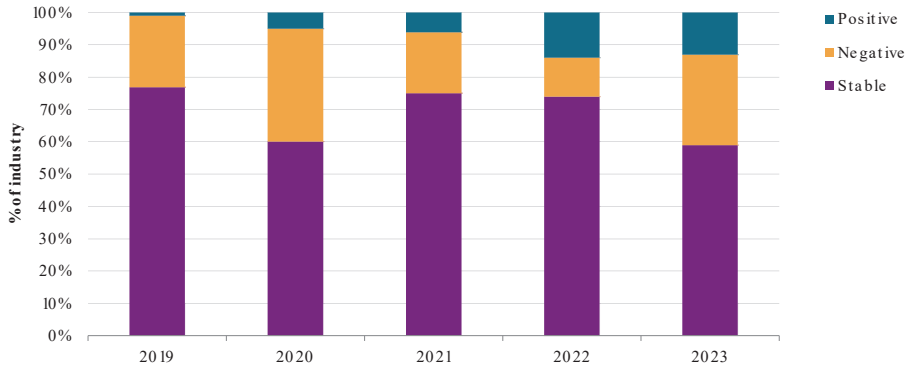
High Percentage Of Negative Outlooks

Currently, about 28% of the industry has a negative outlook or is listed on CreditWatch with negative implications. This is now the third time in the past five years that the year-end percentage of negative outlooks and CreditWatch listings has exceeded 20%. Given the current high percentage of negative outlooks it is increasingly likely that credit quality will again weaken in 2024.

Chart 2

Outlooks for the North American regulated utilities industry
At year end.



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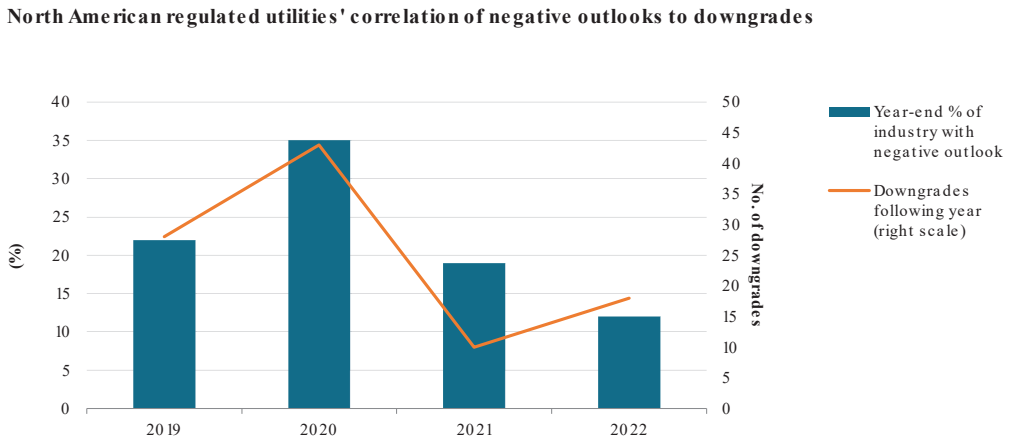
Future rating actions are typically correlated with our outlooks. The industry's share of negative outlooks reached a record high of 35% at year-end 2020, and the following year saw a record 43 downgrades. The industry's current percentage of negative outlooks is significantly larger than it was at year-ends 2021 and 2022, when downgrades still materially outpaced upgrades the following year. As such, given the current high percentage of negative outlooks, we anticipate that 2024 will be another challenging year for the industry's credit quality.

Chart 3



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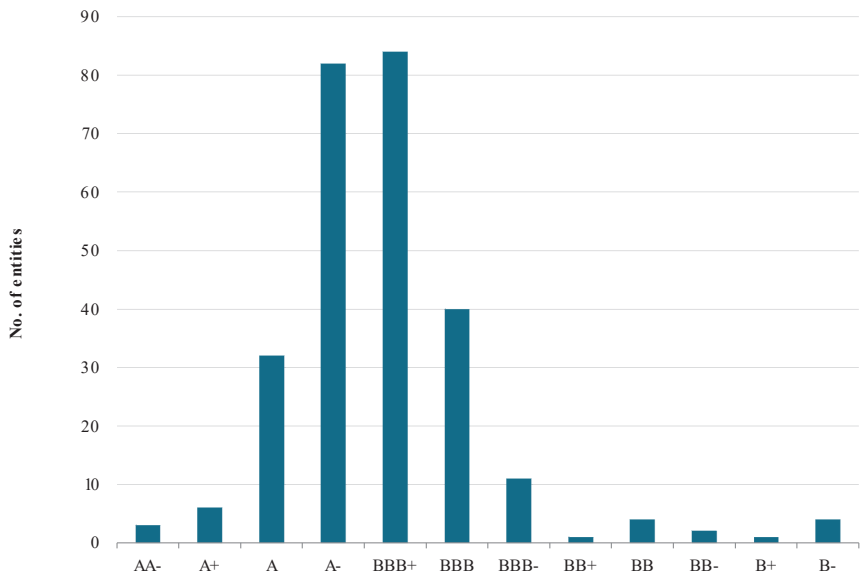
Median Credit Rating To Remain Investment Grade

The median rating among North American investor-owned regulated utilities is 'BBB+'. Despite our expectations for downgrades to again outpace upgrades in 2024, we expect that the median rating will remain 'BBB+'. To weaken the median rating to 'BBB', the industry would need about 70 downgrades to 'BBB' from the 'BBB+' level or above. This degree of credit weakening is well above our base-case expectations for 2024. However, this magnitude of weakening could occur over the next three years if this negative pace persists.

Chart 4

North American regulated utilities ratings distribution
As of Feb. 1, 2024.



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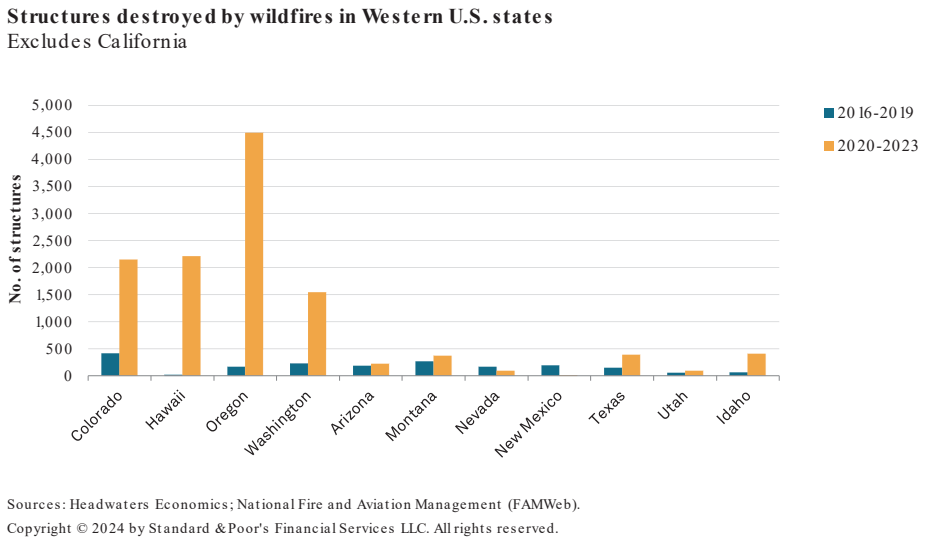
Headwinds To Credit Quality

The industrywide negative outlook reflects rising physical risks as well as financial measures, which are weakening due to rising capital spending and cash flow deficits that are not funded in a sufficiently credit supportive manner. Furthermore, much of the industry operates with minimal financial cushion from their downgrade threshold. This increases the susceptibility to a downgrade if negative events occur beyond our base case.

Increase in physical risk

Climate change and an increase in wildfire risks are threatening credit quality. Wildfire risk was generally limited to California utilities just five years ago but has spread over the past several years.

Chart 5



Sources: Headwaters Economics; National Fire and Aviation Management (FAMWeb).
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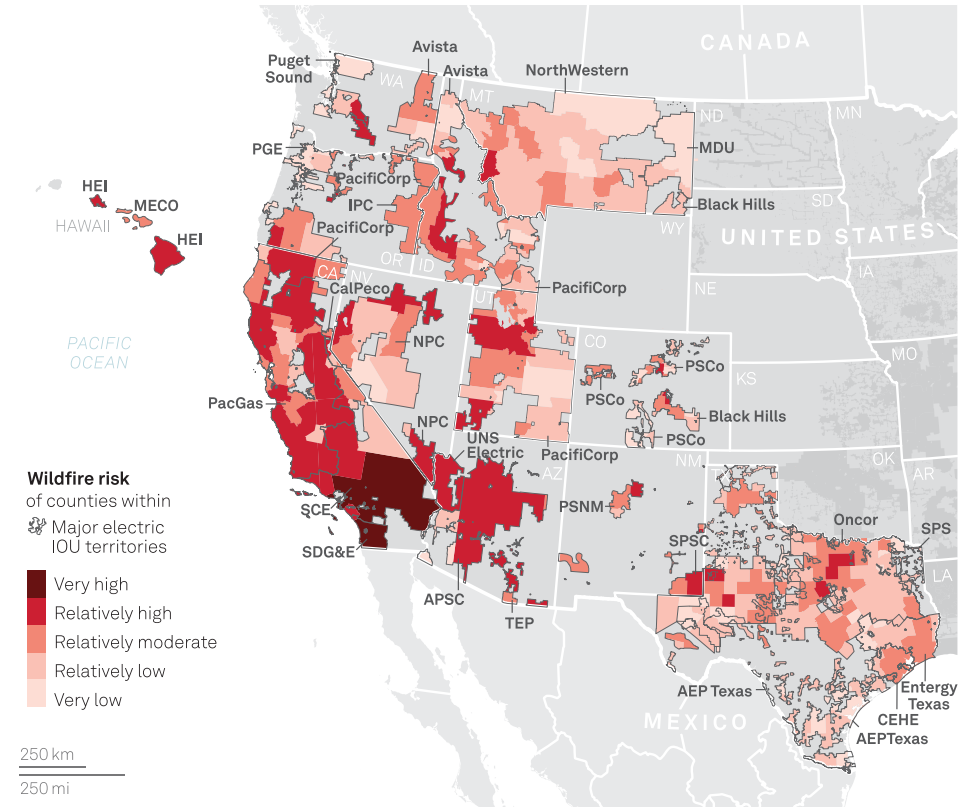
Since 2020, the number of structures destroyed by wildfires in Colorado, Hawaii, Idaho, Oregon, Washington, and Texas have all increased by more than 100% compared to 2016-2019. Meanwhile, Arizona, Montana, and Utah have each experienced increases of at least 20% over the same timeframe. Additionally, areas designated as high fire risk continue to increase across the Western U.S. due to climate change. To reduce these risks, many utilities are actively implementing mitigation plans designed to reduce wildfire exposure and litigation risks.

Wildfire risk across West Coast electricity territories



Source: FEMA, S&P Global Market Intelligence.
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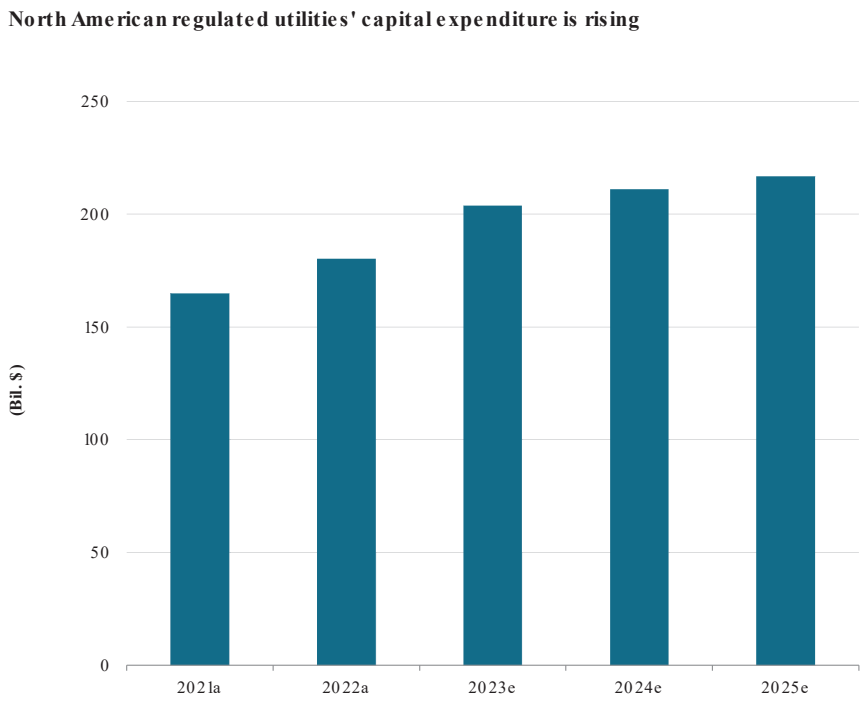
Increase in capital expenditure and cash flow deficits

The industry's capital spending remains at record levels, supporting initiatives for safety, reliability, energy transition, and growth. We consider these trends long term and expect that capital spending will only continue to increase over this decade.

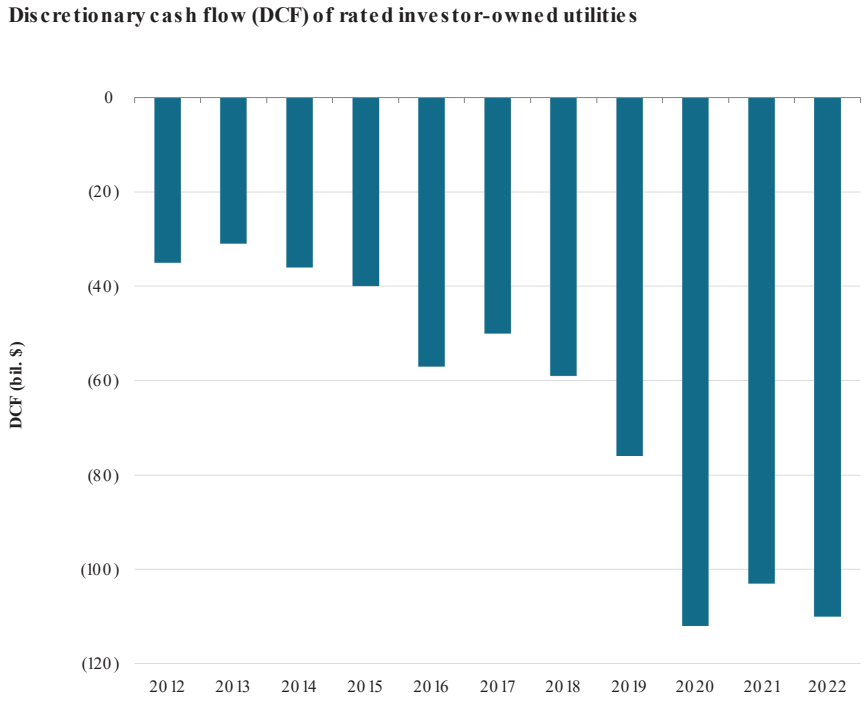
Chart 6



a--Actual. e--Estimate. Source: S&P Global Ratings.

Accordingly, cash flow deficits have increased, pressuring the industry's credit quality. For 2024, our base case assumes that the industry will fund its approximate $85 billion of cash flow deficits with about $40 billion in asset sales and equity issuance.

Chart 7



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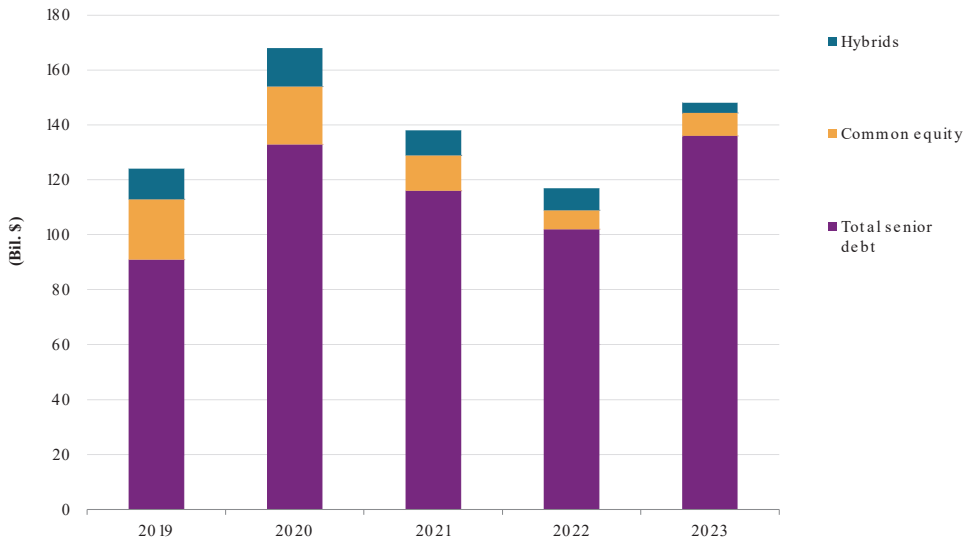
For 2023, the industry's actual equity issuance was considerably below our expectations, resulting in a weakening of financial performance and credit quality. If this trend persists, credit quality will again likely experience pressure in 2024.

Chart 8

Capital market issuance for North American regulated utilities



Senior debt includes first-mortgage bonds and senior unsecured. Hybrids includes junior subordinated debt, preferreds, subordinated debt, and equity units. Source: S&P Global Ratings, S&P Market Intelligence.

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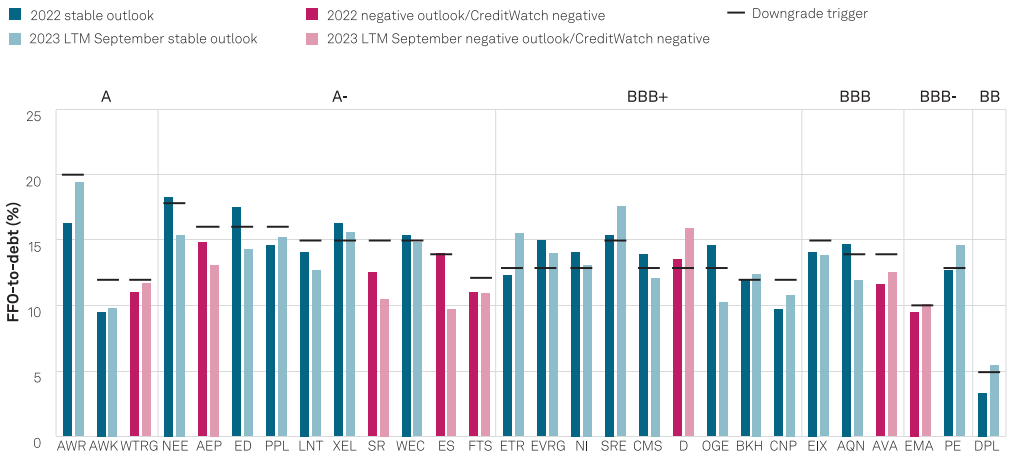
Strained financial cushion

About 35% of the industry is sustaining performance with minimal financial cushion, reflecting funds from operations (FFO) to debt that is less than 100 basis points (bps) above their downgrade threshold. The limited financial cushion affects a company's ability to absorb unexpected events beyond the base case for our ratings, increasing its susceptibility to a downgrade. Such unexpected events include higher interest rates, changes to inflation, delays to offshore wind projects, and rising taxes.

North American regulated utilities with minimal financial cushion



Data as of Feb. 6, 2024. FFO--Funds from operations. LTM--Last 12 months. AWR--American States Water Co. AWK--American Water Works Co. Inc. WTRG--Essential Utilities Inc. NEE--NextEra Energy Inc. AEP--American Electric Power Co. Inc. ED--Consolidated Edison Inc. PPL--PPL Corp. LNT--Alliant Energy Corp. XEL--Xcel Energy Inc. SR--Spire Inc. WEC--WEC Energy Group Inc. ES--Eversource Energy. FTS--Fortis Inc. ETR--Entergy Corp. EVRG--Evergy Inc. NI--NiSource Inc. SRE--Sempra. CMS--CMS Energy Corp. D--Dominion Energy Inc. OGE--OGE Energy Corp. BKH--Black Hills Corp. CNP--CenterPoint Energy Inc. EIX--Edison International. AQN--Algonquin Power & Utilities Corp. AVA--Avista Corp. EMA--Emera Inc. PE--Puget Energy Inc. DPL--DPL Inc.
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Upcoming debt maturities amid higher interest rates

The industry has considerable near-term debt maturities that must be refinanced, as well as rising discretionary cash flow deficits that are mostly funded with debt. Because of the regulatory lag, which is the timing difference between when a utility incurs costs and when it's recovered from ratepayers, rising interest rates weaken financial performance. S&P Global economists expect the federal funds rate will stabilize in 2024 and then begin to modestly decrease. Accordingly, as interest rates stabilize, it will ease pressure on the industry's financial performance.

Additionally, the spread between the 10-year treasury and the average authorized return on equity (ROE) has narrowed. Over the past three years, the 10-year treasury has increased by about 250 bps to about 4.0% from about 1.5% at year-end 2020. At the same time, average authorized ROE has essentially remained flat at about 9.5%. The narrowing of this spread directly hinders the industry's financial performance.

Elevated inflation rates

Although the rate of inflation has slowed from 2022 levels, it remains elevated relative to historical levels. We anticipate this will result in higher operations and maintenance (O&M) costs that could weaken financial performance. While some utilities have interim mechanisms that reduce the regulatory lag, most will have to file rate cases on a more frequent basis if inflation remains higher over the longer term.

Delayed renewable energy projects

Recently, several large offshore wind projects were delayed or canceled because of rising costs for these more challenging projects. For example, we recently placed Eversource Energy's ratings on CreditWatch with negative implications directly related to its share of higher costs associated with its offshore wind projects.

Alternative minimum tax (AMT)

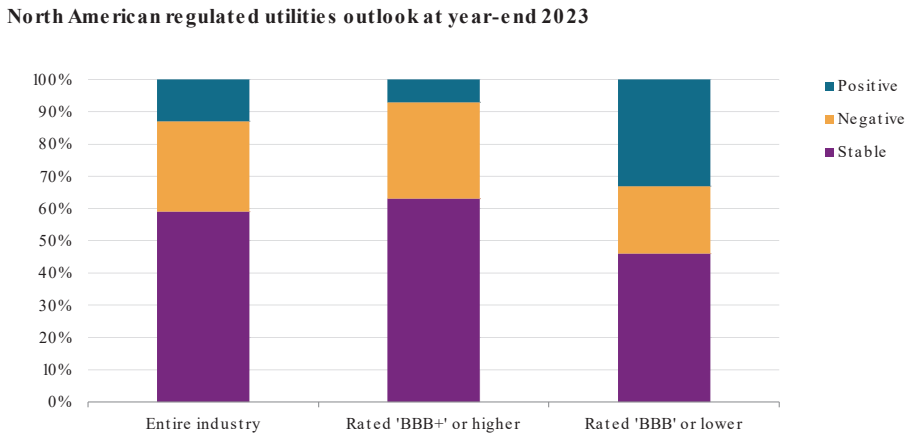
The Inflation Reduction Act of 2022 includes a 15% corporate AMT that we expect will weaken the financial measures of only about 10% of the industry. This is because the ATM is applicable to corporations with at least $1 billion of income that also do not have sufficient offsetting tax credits. Accordingly, we expect that most fully integrated large utilities with a growing or significant renewable generation portfolio will use their renewable tax credits to minimize or eliminate the AMT. However, the AMT could weaken financial measures of large electric transmission and distribution utilities, large natural gas local distribution companies, and large water utilities.

Lower-Rated Companies Will Likely Protect Credit Quality

We expect a majority of the industry's future downgrades will come from companies that are currently rated 'BBB+' or higher, as about 30% of companies in this category have a negative outlook. Overall, these higher-rated companies account for about 75% of the industry's portfolio. Conversely, we expect companies rated 'BBB' or lower will likely take measures to support or improve credit quality. This reflects the more than 30% of companies in this category that have a positive outlook.

Consequently, there is a broad industry trend that is bifurcating higher-rated and lower-rated companies that will likely result in weakening credit quality for the higher-rated companies and stable to improving credit quality for the smaller percentage of lower-rated companies. We believe this trend is consistent with the industry's current economic conditions of robust growth, cash flow deficits, and higher interest rates. Some higher-rated companies are determining that, under current conditions, they have excess credit capacity while lower-rated companies believe it is most optimal for them to operate at a higher rating.

Chart 9



Source: S&P Global Ratings.

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This report does not constitute a rating action.

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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Development of Rates for Transportation ATL Services

Case No.: U-21806
Exhibit No.: A-108 (SAS-6)
Page: 1 of 1
Witness: SASmith
Date: December 2024

Line No.	(a) Description	(b) Storage Revenue Requirement ($000) [1]	(c) Transportation Throughput (MMcf) [2]	(d) Storage Cost Per Mcf of Throughput (b / c)	(e)	(f)
1	Storage Related Cost	$ 22,241	81,455	$ 0.2730		

	ATL as a Percent of ACQ	Present Rates	Proposed Per Mcf of Throughput Adjustment	Storage Cost Difference from Average Per Mcf by ATL Level	Initial Adjusted ATL Throughput Adjustment	Percentage Adjustment To Match XXLT 4% [3]
2	2.00%	$ (0.0732)	$ (0.0781)	$ (0.1905)	$ (0.2680)	29.13%
3	4.00%	$ (0.0507)	$ (0.0540)	$ (0.1081)	$ (0.1856)	29.13%
4	6.50%	$ (0.0225)	$ (0.0240)	$ (0.0050)	$ (0.0825)	29.13%
5	7.50%	$ (0.0113)	$ (0.0120)	$ 0.0363	$ (0.0412)	29.13%
6	8.50%	$ -	$ -	$ 0.0775	$ -	29.13%
7	9.50%	$ 0.0113	$ 0.0120	$ 0.1187	$ 0.0412	29.13%
8	10.50%	$ 0.0225	$ 0.0240	$ 0.1600	$ 0.0825	29.13%
11					XXLT Adjustment [3]	$ (893.31)
12						$ (893.31)
						$ -

Notes

[1] Exhibit A-16 (SMG-2), Schedule F-1.1, page 2, line 5, columns (i) - (l)

[2] Exhibit A-15 (MA-7), Schedule E-3

[3] Adopted methodology from MPSC Staff approved in Case No. U-20322. Directly adjusted the per Mcf storage cost based on the ratio of the ATL tiers and the average ATL of 6.6% (Calculated in WP-SAS-4). This results in a cost per Mcf for each tier of ATL. Then adjusted each of the tiers' adjustments by the percentage necessary to result in the same storage cost adjustment for XXLT at a 4% ATL.

U21806-SA-CE-409
Requested By: Brittney M. Klocke (BMK-11 - 1)
Respondent: Stacy H. Baker
Date of Response: 3/19/2025
Page **1** of **1**

Question:

1) What is the current status of the Company's website redesign?

Response:

The Company has put the website redesign on hold due to extended support of the current on-premises Sitecore web content management system and the Company's SAP S/4HANA planned implementation.

The previous timing for the website redesign was developed with the expectation that the Company would need to migrate to the cloud/Software-as-a-Service (SaaS) version of the Sitecore system based on Sitecore's published product support lifecycle at that time. This would have been a major reason to initiate the website redesign. Since then, Sitecore has extended mainstream support for the on-premises version 10.4 to December 31, 2027, giving the Company more flexibility in its migration schedule.

In addition, the Company's implementation of the SAP S/4HANA system will be a major undertaking, which will significantly impact the design of integration between the Company's website and SAP. The Company plans to complete the S/4HANA implementation before starting the website redesign.

U21806-AG-CE-0615
Page **1** of **1**

Question:

233. Refer to lines 26-38 on page 61 of Ms. Baker's direct testimony on the ARP-OT Support Gas. Please:

a. Describe the problems experienced with servers in the last three years and identify the number of problems experienced.

b. Explain why a 5-year replacement cycle is necessary and whether it could be extended to 7 years with no significant repercussions.

c. If the Company is on a 5-year replacement cycle, why is there a significant variance in capital expenditures from year to year, which vary from $245,000 in 2023 to $2.5 million for the projected test year.

Response:

Objection of Counsel: Consumers Energy Company objections to this discovery request because it is argumentative and requires the adoption of an assumption. Without waiving this objection, Consumers Energy responds as follows:

a. Following are the incidents experienced with servers in the last three years for the ARP-OT Support Gas.

Incident Description	Number of Incidents
Memory and storage failures	5
Power Supply issues	3
Network and connectivity issues	5
Hardware faults and failures	4

b. A five-year refresh cycle for server hardware is considered necessary due to increased risks of hardware failure, performance degradation, and the expiration of support. For a natural gas compressor station, maintaining a reliable local control system is critical for ensuring continuous and safe gas flow.

Extending the refresh cycle to seven years has potential risks such as increased hardware failures, higher maintenance costs, security vulnerabilities, and performance issues. Compliance with TSA regulatory requirements, such as those outlined in API 1164, is crucial. API 1164 mandates regular updates to control system software and firmware to protect against known vulnerabilities and threats.

c. The costs vary from 2023 to the projected test year for the ARP-OT Support Gas project due to the need to refresh assets implemented as a part of the Pipeline SCADA project.

Witness: Stacy H. Baker
Date: March 21, 2025

U21806-AG-CE-0616 Revised
Page **1** of **1**

Question:

234. Refer to lines 16-40 on page 62 and lines 1-5 on page 63 of Ms. Baker's direct testimony on the ARP-Physical Security. Please:

a. Identify the problems experienced with security assets in the last three years and the number of problems experienced.

b. Explain why the Company needs advanced door systems and how these systems differ from current door systems.

c. Regarding security cameras, gate and lock systems, confirm that these devices and systems are already in place at the Company. If confirming, explain what is being proposed for the additional expenditures. If not confirming, explain why these devices and systems are not already being used.

d. Regarding Alternatives 1 and 2, what are the specific risks that would exist?

Response:

a. Incidents experienced with physical security assets include cameras no longer working, wiring issues, require cleaning, transmitter failures, hard drive failures, reader failures, door strike failures, and control board failures. Following is a table with the number of incidents for the last three years related to physical security assets.

Year	Number of Incidents
2022	758
2023	554
2024	568

b. Referring to the ARP-Physical Security project starting on page 62, line 16 through page 63, line 5, the Company ~~requires~~ needs to refresh advanced door systems to avoid physical security vulnerabilities and meet FERC requirements. These systems are the same as the current door systems.~~, as the current badges can be easily cloned by off the shelf equipment leading to security vulnerabilities. This project would upgrade badge readers and control boards with encryption.~~

c. Yes, the Company currently uses security cameras, motorized gates, and exterior pedestrian doors at occupied facilities controlled by badge readers for access. Referring to the ARP-Physical Security project starting on page 62, line 16 through page 63, line 5, this project refreshes existing devices to reduce physical security vulnerabilities and meet FERC requirements. ~~This project would upgrade badge readers and control boards with encryption to reduce security vulnerabilities.~~

d. By not refreshing physical security assets or deferring a portion of the asset refreshes, the Company risks utilizing older, unsupported equipment, which results in continued security vulnerabilities and increased O&M costs to maintain older equipment.

Witness: Stacy H. Baker
Date: ~~3/21/2025~~ 5/6/2025

U21806-SA-CE-176
Requested By: Emma Zichi (EZ-4 - 41)
Respondent: Stacy H. Baker
Date of Response: 2/7/2025
Page **1** of **1**

Question:

41. Regarding A-22 (SHB-7), the "ARP-Local Area Network" project:
a. Please provide a breakdown for the costs in line 11 and 30 "Software, labor, contractor and overhead and other costs" to show which categories make up the total cost for 2024, 2025 and 2026.
b. Why did the "Avg. Unit Cost" (column b) for the following significantly increase for 2025 and 2026, compared to 2023 and 2024?
i. Line 1 "LAN Switch A", line 2 "LAN Switch B", line 3 "LAN Switch C", line 5 "LAN Switch E".
c. Why are the materials costs the exact same in Exhibit A-20 (SHB-5) when the breakdown of materials shown in Exhibit A-22 is $225,000 for 2025 and $375,000 for 2026

Response:

a. The gas allocation cost breakdown for software, labor, contractor, non-labor overhead, and non-labor other costs in Exhibit No. A-22 (SHB-7), page 6, lines 11 and 30 for 2024, 2025, and 2026 for the ARP-Local Area Network project are provided in Exhibit A-20 (SHB-5), lines 178, 269, and 349 in columns m, o, p, q, and r.

b. The material naming convention used – for example, LAN Switch A, LAN Switch B, LAN Switch C, etc. - is solely to differentiate each model within a given calendar year. The actual models associated with these designations may change from year to year, which can result in variations in unit pricing.

    i. Refer to part b response.

c. In Exhibit A-20 (SHB-5), lines 269 and 349, column n, the gas allocation material costs for 2025 and 2026 are $108,518 and $180,863 respectively. These amounts are not the same. In Exhibit A-22 (SHB-7), page 6, lines 1 through 10, columns e and f, the total Company material costs for 2025 and 2026 are $225,000 and $375,000 respectively. Exhibit A-20 (SHB-5) provides the gas allocation amounts, while Exhibit A-22 (SHB-7) provides the total Company amounts.

U21806-CUB-CE-0121
Page **1** of **1**

Question:

17. Refer to Baker, pp. 54-55, discussing changes in the projected costs of the Gas SCADA Software Solutions project from previous projections in Case No. U-21490. Baker states, "The contractor costs increased because the vendor professional services were underestimated in the ROM estimate." Please explain how and why the contractor costs were underestimated.

Response:

17. The contractor costs for the vendor professional services were not fully known until the Company conducted a Request for Proposal and received vendor cost estimates based on detailed requirements. Additionally, as discussed in my direct testimony on page 55, lines 4-5, the Company determined that additional third-party resources were required to support testing this new technology.

Witness: Stacy H. Baker
Date: February 20, 2025

U21806-CUB-CE-0122
Page **1** of **1**

Question:

18. Refer to Baker, pp. 54-55, discussing changes in the projected costs of the Gas SCADA Software Solutions project from previous projections in Case No. U-21490. Baker states, "The contractor costs increased because the vendor professional services were underestimated in the ROM estimate." Please explain what services the contractors perform.

Response:

18. The professional services vendor is responsible for providing product and industry experience, building the new solution, which includes, but is not limited to, configuring their products, creating new SCADA screen displays, developing an automated, repeatable process to migrate SCADA information from the current system, configuring and building interfaces to the Historian and Geographic Information System (GIS) systems, and conducting the corresponding testing and project management to ensure a quality solution. Additionally, the Company found that it lacked sufficient internal resources and skills to support user acceptance and parallel testing. Therefore, the Company contracted a third-party to provide additional resources to assist, guide, and support testing of the solution.

Witness: Stacy H. Baker
Date: February 20, 2025

U21806-CUB-CE-0123
Page **1** of **1**

Question:

19. Refer to Baker, pp. 54-55, discussing changes in the projected costs of the Gas SCADA Software Solutions project from previous projections in Case No. U-21490. Baker states, "The contractor costs increased because the vendor professional services were underestimated in the ROM estimate." Please explain why the services the contractors perform cannot be performed in-house.

Response:

19. Building and implementing the new solution requires a level of expertise and resources that necessitates leveraging outside services. The Company lacks the internal gas resources with the necessary expertise and experience to implement the software products.

Witness: Stacy H. Baker
Date: February 20, 2025

U21806-CUB-CE-0124
Page **1** of **1**

Question:

20. Refer to Baker, pp. 54-55, discussing changes in the projected costs of the Gas SCADA Software Solutions project from previous projections in Case No. U-21490. Baker states, "The software licensing costs increased because the ROM estimate planned for a five-year period, but the project required six years of software subscriptions due to the length of the implementation." Please explain why the implementation is taking longer than planned.

Response:

20. The reason the software licensing costs increased is not because the implementation is taking longer than planned, but rather because the planned implementation is more than two years. The Company requires that a software asset have at least a three-year expected life after implementation for capitalization. As the Company refined the initial cost projections it identified that due to the implementation being more than two years, the Company was required to purchase six years of software subscriptions to ensure there was a three-year expected life.

Witness: Stacy H. Baker
Date: February 20, 2025

U21806-CUB-CE-0125
Page **1** of **1**

Question:

21. Refer to Baker, pp. 54-55, discussing changes in the projected costs of the Gas SCADA Software Solutions project from previous projections in Case No. U-21490. Baker states, "The material costs increased because the ROM estimate planned to purchase physical servers, but the Company decided to purchase virtual servers. The Company utilizes virtual servers because they provide cost efficiency, maximize the use of available resources, and offer more flexibility." Please explain how switching to more cost-efficient virtual servers resulted in increased material costs.

Response:

21. The virtual servers cost more upfront due to the hypervisor software licensing required for the hardware to function. The cost efficiencies gained are less on-going support and the flexibility to maximize the use of available server resources without purchasing additional servers. Managing the life cycle of virtual servers is more efficient. For example, rolling out firmware, operating system (OS) upgrades, and patches is more efficient with virtual servers, as it can be done once and deployed automatically and dynamically across many virtual servers. In contrast, physical servers require scheduling an outage, taking down each server, and applying the firmware and OS upgrades one by one.

Witness: Stacy H. Baker
Date: February 20, 2025

U21806-CUB-CE-0126
Page **1** of **1**

Question:

22. Refer to Baker, pp. 54-55, discussing changes in the projected costs of the Gas SCADA Software Solutions project from previous projections in Case No. U-21490. Baker states, "The material costs increased because the ROM estimate planned to purchase physical servers, but the Company decided to purchase virtual servers. The Company utilizes virtual servers because they provide cost efficiency, maximize the use of available resources, and offer more flexibility." Please explain why the Company did not identify virtual servers as the better option during the ROM estimate phase.

Response:

22. The Company did not identify virtual servers during the initial cost projection development because it implemented the new operational technology standard to utilize virtual servers afterward.

Witness: Stacy H. Baker
Date: February 20, 2025

U21806-AG-CE-0613
Page **1** of **1**

Question:

231. Refer to page 54 of Ms. Baker's direct testimony on the SCADA project. Please:

a. Provide the current phase of development of the project.

b. Identify the start and completion dates of the detailed requirements phase of the project.

c. Provide the actual amount spent in 2024 for capital expenditures and O&M expense and the forecasted amount of capital expenditures for the 10 months ending October 2025 and for the projected test year.

d. Provide the amount of capital expenditures and O&M expense to be incurred in future years past 2025 by year.

Response:

a. The Gas SCADA Software Solution project is currently in the Execute phase.

b. The detailed requirements occurred from 04/1/22 to 10/31/22.

c. Refer to Attachment No. U21806-AG-CE-0613_ATT 1 for the updated total projected project costs including the preliminary actual 2024 capital expenditures and O&M expense. The projected gas allocation capital expenditures for the 10 months ending October 2025 are $4,220,803 and $3,080,968 for the projected test year.

d. Refer to part c response.

Witness: Stacy H. Baker
Date: 3March 21, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas SCADA Software Solution

Attachment: U21806-AG-CE-0613_ATT 1
Witness: SHBaker
Date: March 2025

Gas SCADA Software Solution				
Cost Category	**Total Company Capital**	**Gas Allocation Capital**	**Total Company O&M**	**Gas Allocation O&M**
2023 Actuals				
Software	$708,742	$708,742	$0	$0
Material	$946,533	$946,533	$0	$0
Labor	$53,782	$53,782	$149,361	$149,361
Contractor Costs	$219,054	$219,054	$1,788	$1,788
Non-Labor Overhead	$4,241	$4,241	$10,211	$10,211
Non-Labor Other	$17,212	$17,212	$0	$0
Total 2023 Actuals	**$1,949,564**	**$1,949,564**	**$161,360**	**$161,360**
2024 Preliminary Actuals				
Software	$433,785	$433,785	$88,847	$88,847
Material	$866,626	$866,626	$137,912	$137,912
Labor	$584,162	$584,162	$17,382	$17,382
Contractor Costs	$1,284,033	$1,284,033	$86	$86
Non-Labor Overhead	$0	$0	$0	$0
Non-Labor Other	$235,536	$235,536	$4,111	$4,111
Total 2024 Preliminary Actuals	**$3,404,142**	**$3,404,142**	**$248,338**	**$248,338**
2025 Projected				
Software	$2,609,645	$2,609,645	$91,513	$91,513
Material	$7,264	$7,264	$167,070	$167,070
Labor	$916,466	$916,466	$161,195	$161,195
Contractor Costs	$1,071,798	$1,071,798	$79,625	$79,625
Non-Labor Overhead	$0	$0	$0	$0
Non-Labor Other	$459,791	$459,791	$33,233	$33,233
Total 2025 Projected	**$5,064,964**	**$5,064,964**	**$532,636**	**$532,636**
2026 Projected				
Software	$197,951	$197,951	$291,343	$291,343
Material	$0	$0	$0	$0
Labor	$161,195	$161,195	$35,544	$35,544
Contractor Costs	$2,081,008	$2,081,008	$418,977	$418,977
Non-Labor Overhead	$0	$0	$0	$0
Non-Labor Other	$244,015	$244,015	$74,586	$74,586
Total 2026 Projected	**$2,684,169**	**$2,684,169**	**$820,450**	**$820,450**
Total Actuals/Projected				
Software	$3,950,123	$3,950,123	$471,703	$471,703
Material	$1,820,423	$1,820,423	$304,982	$304,982
Labor	$1,715,605	$1,715,605	$363,483	$363,483
Contractor Costs	$4,655,893	$4,655,893	$500,475	$500,475
Non-Labor Overhead	$4,241	$4,241	$10,211	$10,211
Non-Labor Other	$956,555	$956,555	$111,931	$111,931
Total Actuals/Projected	**$13,102,839**	**$13,102,839**	**$1,762,785**	**$1,762,785**

U21806-AG-CE-0614
Page **1** of **2**

Question:

232. Refer to pages 50 and 51 of Ms. Baker's direct testimony on the SCADA project. Please:

a. Identify by how much and by what percentage the contractor costs were underestimated and explain why.

b. Confirm that the SCADA project was competitively bid to various vendors. Identify the number of vendors contacted, the number of bids received, and which vendor was selected and why.

c. Provide a copy of the bids received and the analysis showing why the chosen vendor was selected.

d. Explain why a third-party consultant is needed for expertise with the technology when the vendor should provide the needed expertise for the technology they sell.

e. Provide the name pf the third-party and the amount to be paid to this party by year and whether it is included in O&M expense or capital expenditures.

f. Explain whether the Company issued requests for proposals for the third-party, the number of bids received. Provide a copy of the bids received and the analysis showing why the chosen vendor was selected.

g. Identify the length of the implementation. Did the Company consider spreading the implementation over a longer time period to reduce the impact on capital expenditures in the next few years?

h. Explain how the Company uses virtual servers and with whom. If virtual servers are cost efficient, why did they increase the cost of the project?

Response:

a. Refer to Attachment No. U21806-AG-CE-0613_ATT 1 for the updated total projected project costs including the preliminary actuals 2024 capital expenditures and O&M expense. The current projected contractor costs are $4.66 million, which is consistent with the $4.63 million projected in Case No. U-21490.

b. The Gas SCADA Software Solution project conducted a Request for Proposal (RFP) to competitively bid to six vendors. Of the six vendors, three elected not to participate, one vendor could not meet the full requirements, and the vendor selected was Open Systems International, Inc. (now Aspentech).

c. Refer to Attachments U21806-AG-CE-0614_ATT_1_CONF, U21806-AG-CE-0614_ATT_2_CONF, U21806-AG-CE-0615_ATT_3_CONF, and U21806-AG-CE-0615_ATT_4_CONF for a copy of the bids received and the analysis showing why the chosen vendor was selected.

d. Black and Veatch is uniquely qualified to perform the execution and testing support services. Their prior services were key to building the project's detailed requirements that were used in the RFP to ultimately select the best solution. A large part of their services are requirements traceability, ensuring that all requirements have been met in the vendor-built solution and that all testable requirements are indeed tested. Black and Veatch will be building and executing scripts to do parallel

testing, validation to ensure the new solution behaves the same as the existing solution for retrieval of SCADA data from our many endpoints. Further, they will be creating the User Acceptance Test (UAT) testing scripts for the Company to perform to ensure a fully tested solution and readiness for go-live. Both require a deep understanding of our existing gas SCADA environment as well as a solid understanding of our Gas SCADA project requirements. Given the Black and Veatch history on this project, along with the continuity of their personnel, Black and Veatch is uniquely positioned for this testing work.

e. The table below provides the third-party consultant, Black and Veatch, costs total company capital expenditures and O&M expense by year.

Year	Capital	O&M
2025	$625,000	$35,000
2026	$75,000	$35,000
Total	**$700,000**	**$70,000**

f. The Company did not conduct a request for proposal for the third-party.

g. The capital expenditures started for this project in 2023 and are currently planned through February 2026. The original planned Go Live in December 2025 has been extended to February 2026 due to resource availability during the field construction season. Refer to my direct testimony, page 50, line 7 through page 51, line 33, for why the Company determined the current implementation timeline was necessary, as the current system is operating well beyond its original design specifications.

h. The virtual servers cost more upfront due to the hypervisor software licensing required for the hardware to function. The cost efficiencies gained are less on-going support and the flexibility to maximize the use of available server resources without purchasing additional servers. Managing the life cycle of virtual servers is more efficient. For example, rolling out firmware, operating system (OS) upgrades, and patches is more efficient with virtual servers, as it can be done once and deployed automatically and dynamically across many virtual servers. In contrast, physical servers require scheduling an outage, taking down each server, and applying the firmware and OS upgrades one by one.

Witness: Stacy H. Baker
Date: March 24, 2025

U21806-AG-CE-0847
Page **1** of **2**

Question:

397. Refer to discovery response AG-CE-0614 on the SCADA IT project. Please:

a. The answer to subpart (a) is not responsive to the question. Line 1 of page 55 of Ms. Baker's direct testimony states that contractor costs represented $4.4 million of the $6.6 million total increase in costs. Provide the initial contractor costs before the $4.4 million increase.

b. Regarding the response to subpart (h), who owns and runs the virtual servers? Explain how virtual servers differ from cloud computing.

c. Provide the total SCADA project costs by component as originally estimated at time of approval compared to the costs now and justify in detail any variance of 10% or greater in Excel.

Response:

a. The total Company and gas allocation initial contractor costs from the initial estimate of the Gas SCADA Software Solution project in Case No. U-21308 was $1,800,000 capital expenditures.

b. The Company owns and operates the virtual servers on-premises in our data center for the Gas SCADA Software Solution project because the system is critical for providing safe and reliable gas service. These virtual servers are physically located in the Company's data center, while virtual servers in the cloud are located in Azure's data center, for example, that the Company would subscribe to.

c. The table below provides increase/decrease between the total project costs for the initial estimate provided in Case No. U-21308 and the current estimate provided in response No. U21806-AG-CE-0614. Following are explanations for cost category increases greater than 10%.

The software licensing costs increased because they were initially underestimated and the initial estimate planned for a five-year period, but the project required six years of software subscriptions due to the length of the implementation. The material costs increased because the initial estimate planned to purchase physical servers, but the Company decided to purchase virtual servers. The Company utilizes virtual servers because they provide cost efficiency, maximize the use of available resources, and offer more flexibility. The contractor costs increased because the vendor professional services were underestimated in the initial estimate. Additionally, the Company determined that a third-party was required to support internal resources with testing, as the technology is new to the Company. In U-21308 Overheads & Other Costs were one cost category. In this case, U-21806, the Company began using two cost categories, Non-Labor Overhead and Non-Labor Other. There is a net decrease between the initial estimate for Overheads & Other Costs and the current estimate for Non-Labor Overhead and Non-Labor Other.

Refer to U21806-CUB-CE-0123 through U218096-CUB-CE-0126, for additional variance explanation.

U21806-AG-CE-0847
Page **2** of **2**

Refer to Attachment No. U21806-AG-CE-0847_ATT_1 for the detailed total Company and gas allocation initial estimate by year for the Gas SCADA Software Solution project in Case No. U-21308. Refer to Attachment No. U21806-AG-CE-0614_ATT_1 for the current detailed total Company and gas allocation estimate by year for this project.

	U-21308		Current Estimate		Increase/(Decrease)	
Cost Category	**Total Company/ Gas Allocation Capital**	**Total Company/ Gas Allocation O&M**	**Total Company/ Gas Allocation Capital**	**Total Company/ Gas Allocation O&M**	**Capital**	**O&M**
Software	$2,100,000	$40,000	$3,950,123	$471,703	$1,850,123	$431,703
Material	$400,000	$-	$1,820,423	$304,982	$1,420,423	$304,982
Labor	$1,718,125	$725,000	$1,715,605	$363,483	($2,520)	($361,517)
Contractor Costs	$1,800,000	$-	$4,655,893	$500,475	$2,855,893	$500,475
Overheads & Other Costs	$2,792,750	$139,585	$-	$-	($2,792,750)	($139,585)
Non-Labor Overhead	$-	$-	$4,241	$10,211	$4,241	$10,211
Non-Labor Other	$-	$-	$956,555	$111,931	$956,555	$111,931
Total Project	**$8,810,875**	**$904,585**	**$13,102,839**	**$1,762,785**	**$4,291,964**	**$858,200**

Witness: Stacy H. Baker
Date: April 15, 2025

Industry Credit Outlook 2025

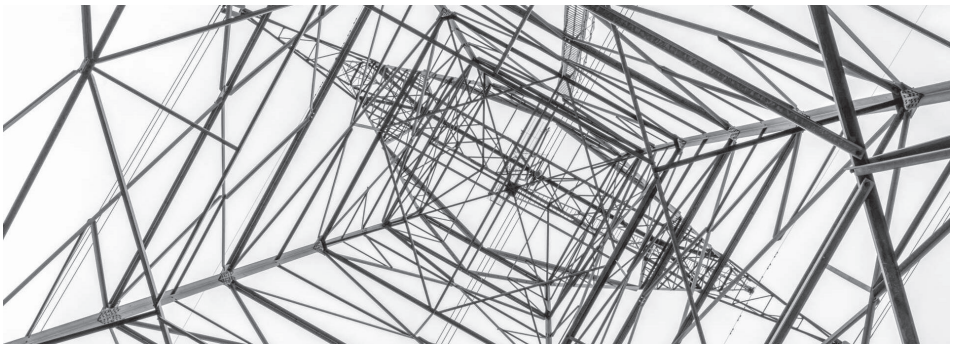
S&P Global Ratings

North America Regulated Utilities

Capex and climate change pressures credit quality

January 14, 2025

This report does not constitute a rating action.



What's changed?

Lower ratings headroom. A high percentage of companies are operating with only minimal financial cushion from our downgrade threshold.

Rising capital spending, higher cash flow deficits, and increased wildfire risks led to downgrades outpacing upgrades for the fifth consecutive year.

Data centers spur electricity sales growth at about 1% annually, which will provide modest support to credit quality.

What are the key assumptions for 2025?

High cash flow deficits of about $100 billion, which could harm financial performance if not funded in a credit-supportive manner.

Robust dividends of about $50 billion for 2025 and at a dividend payout ratio of about 60%.

Record amount of hybrid securities. The industry issued $26 billion of them in 2024, and we expect this trend will persist.

What are the key risks around the baseline?

Rising wildfire risks stemming from climate change.

Tax legislation could weaken financial measures if the new Republican administration lowers the corporate tax rate, reduces tax credits, or eliminates their transferability.

Common equity issuance is below our base-case expectations, and has been for the last several years, leading to weaker financial measures.

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Ratings Trends: North America Regulated Utilities

Chart 1

Ratings distribution

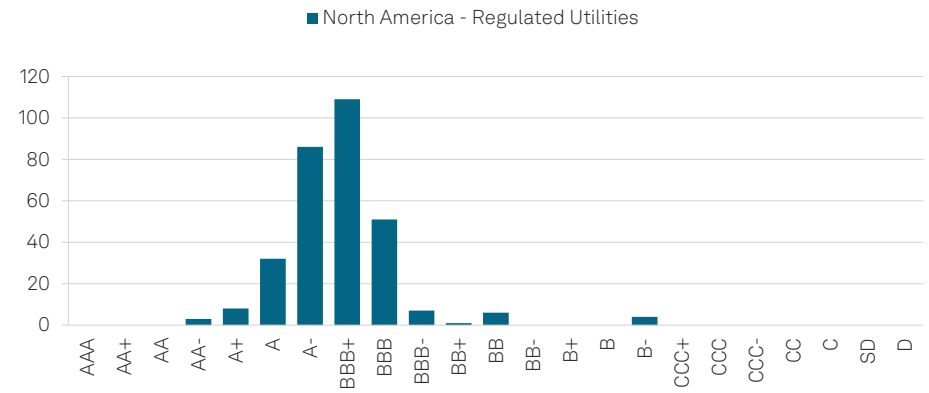


Chart 2

Ratings outlooks

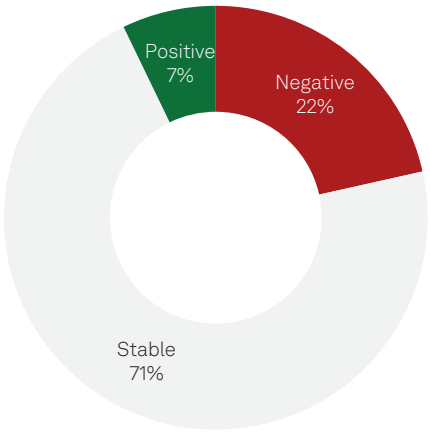
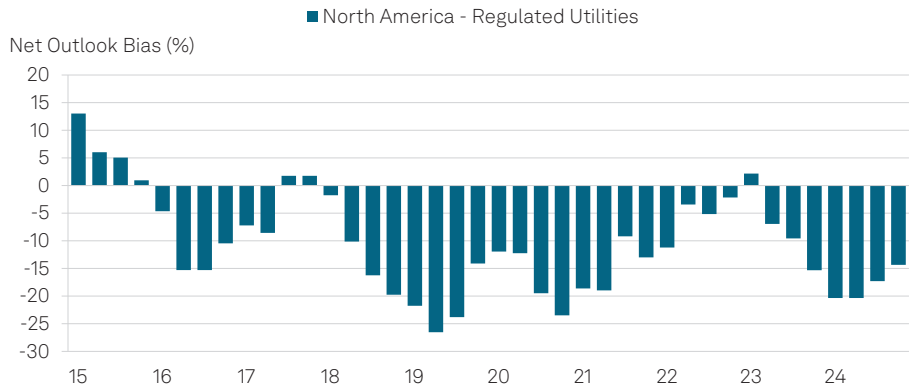


Chart 3

Ratings outlook net bias



Source: S&P Global Ratings. Ratings data measured at quarter-end.

Industry Credit Metrics: North America Regulated Utilities

Chart 4

Debt / EBITDA (median, adjusted)

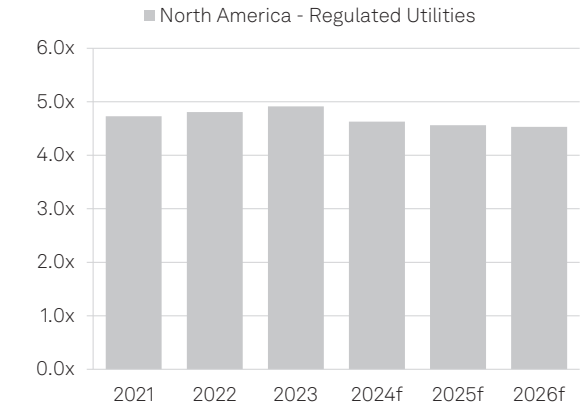


Chart 5

FFO / Debt (median, adjusted)

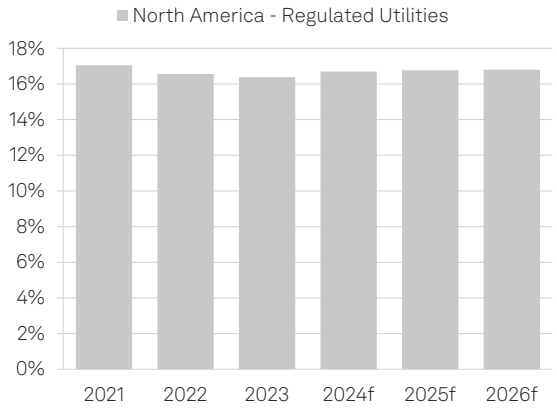


Chart 6

Cash flow and primary uses

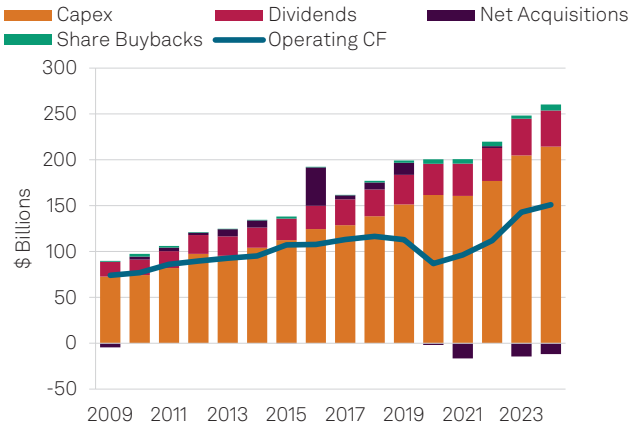
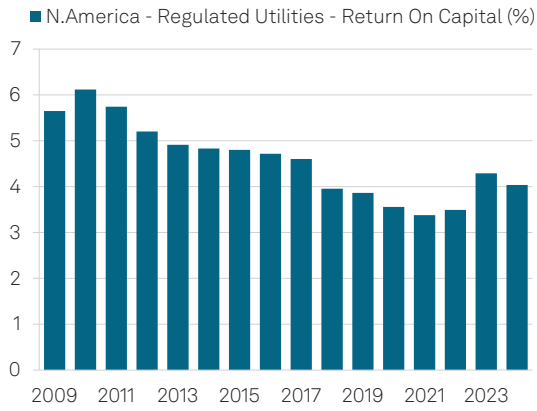


Chart 7

Return on capital employed



Source: S&P Global Ratings, S&P Capital IQ.
Revenue growth shows local currency growth weighted by prior-year common-currency revenue share. All other figures are converted into U.S. dollars using historic exchange rates. Forecasts are converted at the last financial year-end spot rate. FFO—Funds from operations. Most recent (2024) figures for cash flow and primary uses and return on capital employed use the last 12 months' data.

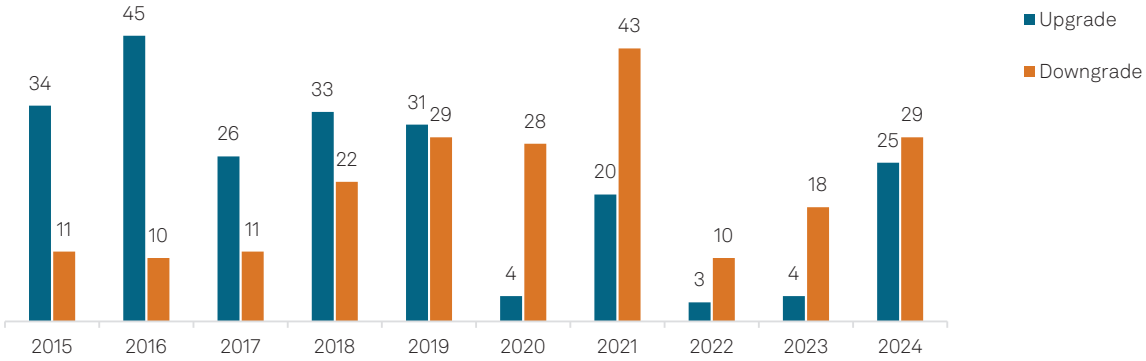
Industry Outlook

Ratings trends and outlook

In 2024, downgrades among North America's investor-owned regulated utilities outpaced upgrades for the fifth consecutive year (see chart 8). Most were directly attributable to rising wildfire risks, robust capital spending, and challenging regulatory constructs. We expect these risks will persist for 2025, further pressuring the industry's credit quality.

Chart 8

North America regulated utilities' upgrades and downgrades



Source: S&P Global Ratings.

Main assumptions about 2025 and beyond

1. Record capital spending.

The industry is heavily investing in safety, reliability, energy transition, and data centers. We expect this spending will exceed $300 billion before the end of the decade.

2. Management of regulatory risk.

This includes constructive rate case orders, minimizing regulatory lag, and earning the authorized return on equity (ROE).

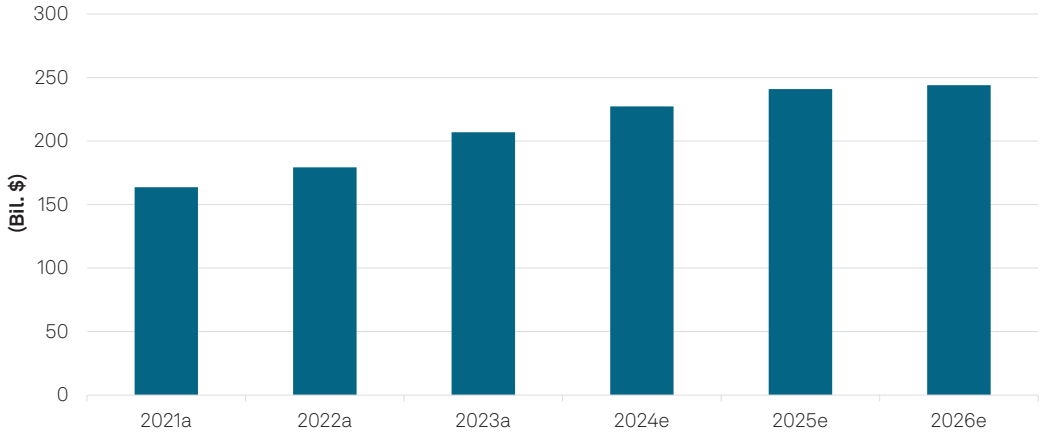
3. Climate change increases risks.

The growing frequency of devastating physical events, including hurricanes, storms, and wildfires, is elevating the industry's credit risks.

Capital spending continues to break records. We expect capital spending for North America's electric, gas, and water utilities will grow by a compound annual growth rate (CAGR) of about 10%. Accordingly, we expect 2025 capital spending to reflect about $240 billion (see chart 9). To date, the industry's capital spending has been primarily focused on safety, reliability, and energy transition.

Chart 9

North America regulated utilities' rising capital expenditures

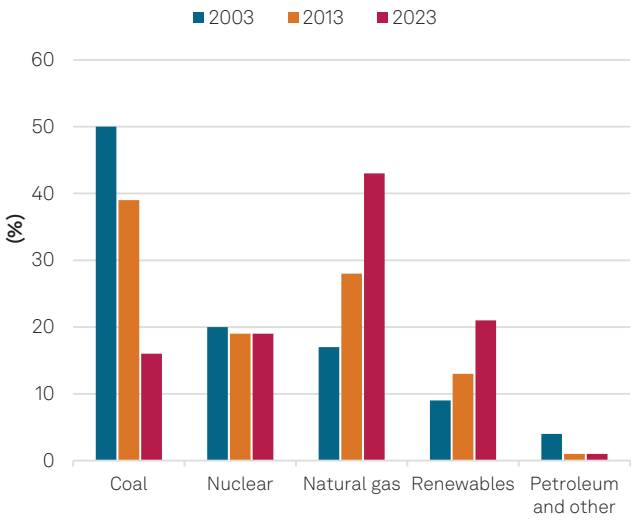


a—Actual. e—Estimate. Capital expenditures represent North American investor-owned electric gas, and water utilities.
Source: S&P Global Ratings.

Energy transition remains key. Over the past decade the industry has invested billions on reducing its reliance on coal-fired generation by about 50% (see chart 10), and today, coal represents only about 15% of total electric generation. Most of the coal was replaced with natural gas, which has about half the carbon emissions. We expect the industry will replace most of its remaining coal-fired generation by about 2030 with renewables and batteries, further reducing its carbon and greenhouse gas (GHG) emissions. The industry has reduced its GHG emissions by nearly 30% over the past decade (see chart 11), and we expect it will reduce them by another 30% by 2035.

Chart 10

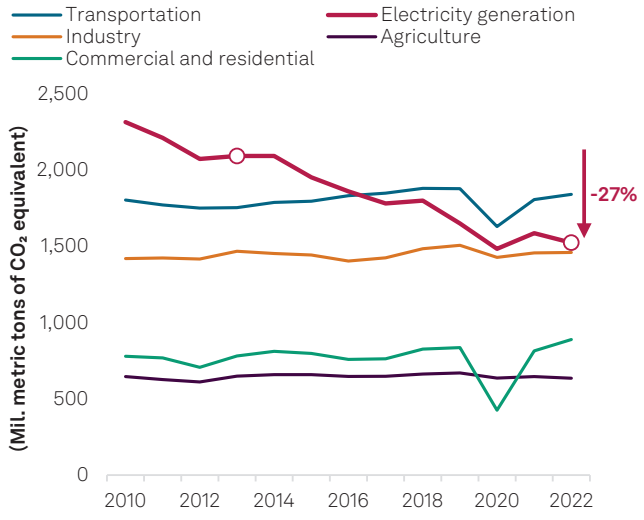
U.S. generation transformation



Source: U.S. Energy Information Administration.

Chart 11

GHG emissions by economic sector (2010-2022)

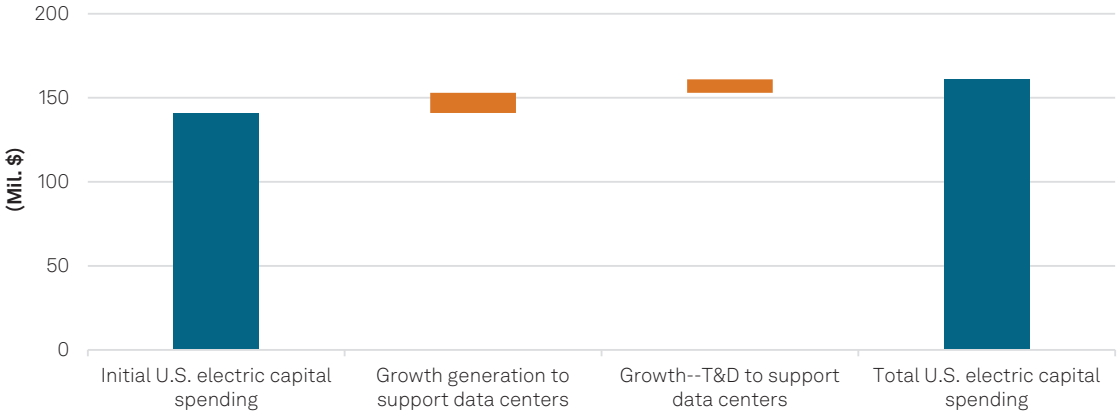


Source: U.S. Environmental Protection Agency.

Data center growth is relatively new, and our current base-case assumptions do not fully incorporate the incremental spending necessary for it. The higher spending for data centers is more likely to begin in 2026. Accordingly, 2026 capex could potentially increase by about another 15% above our current base case (see chart 12).

Chart 12

Data center growth will increase U.S. electric utility annual capital spending by about 15%

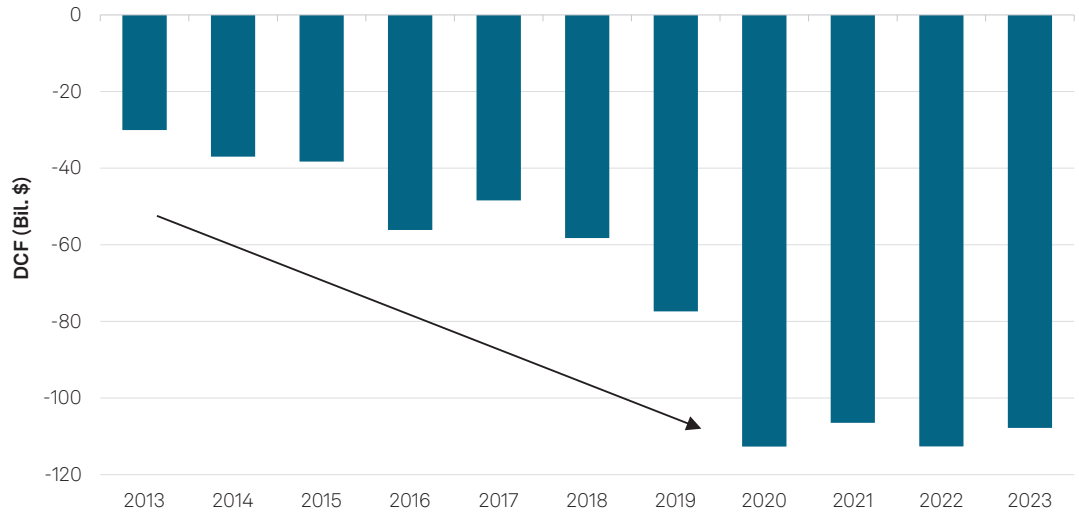


T&D—Transmission and distribution. Source: S&P Global Ratings.

Cash flow deficits will rise as a result, increasing the pressure on the industry's credit quality. Over the past decade the industry's cash flow deficits have grown from about $50 billion to consistently over $100 billion (see chart 13), and we expect this trend will continue.

Chart 13

North America regulated utilities' cash flow deficits



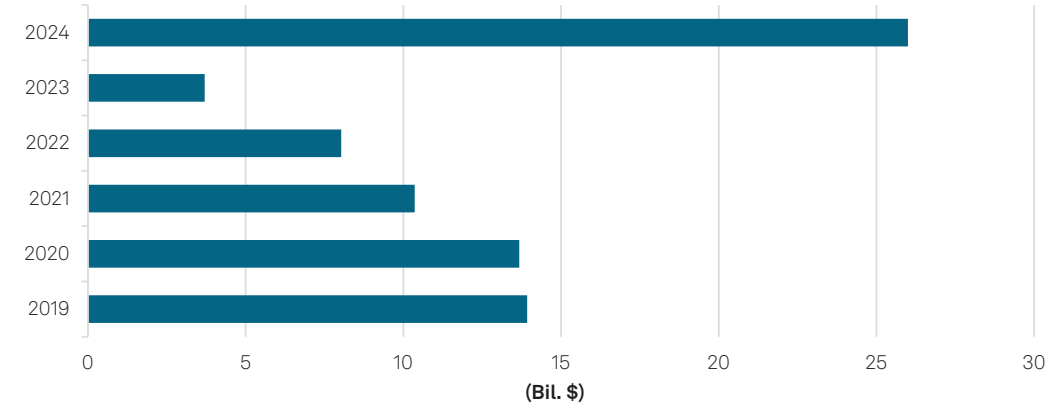
DCF—Discretionary cash flow. Sources: S&P Global Capital IQ, S&P Global Ratings.

Hybrid security issuance reached an all-time high of about $26 billion in 2024, far exceeding the previous record of about $14 billion in 2019 (see chart 14). We expect the industry will maintain this level of issuance in 2025 given its increased capital spending. This robust issuance supported the industry's 2024 financial measures because we typically assess hybrid securities as more

credit supportive than debt, with most of these securities having intermediate (50%) or high (100%) equity content.

Chart 14

North America regulated utilities' annual hybrid securities issuance

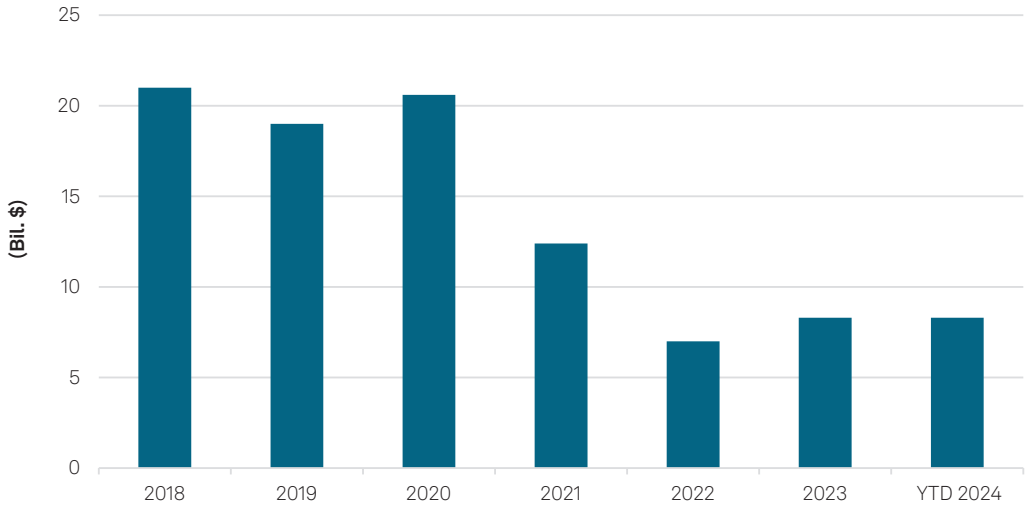


Sources: S&P Global Ratings, S&P Global Market Intelligence.

Common equity issuance has been weak and consistently below our expectations since 2021, pressuring the industry's financial measures. It raised only about $8 billion in 2024, and we estimate that the full year will reflect only about $10 billion. This is well below the industry's average run rate of about $20 billion annually between 2018-2020 (see chart 15). We expect 2025 common equity issuance will again be relatively weak and more reflective of 2024 levels. Without significantly more common equity issuance, we expect the industry's financial measures will continue to weaken, albeit gradually, supporting our negative outlook.

Chart 15

North America regulated utilities' common equity issuance



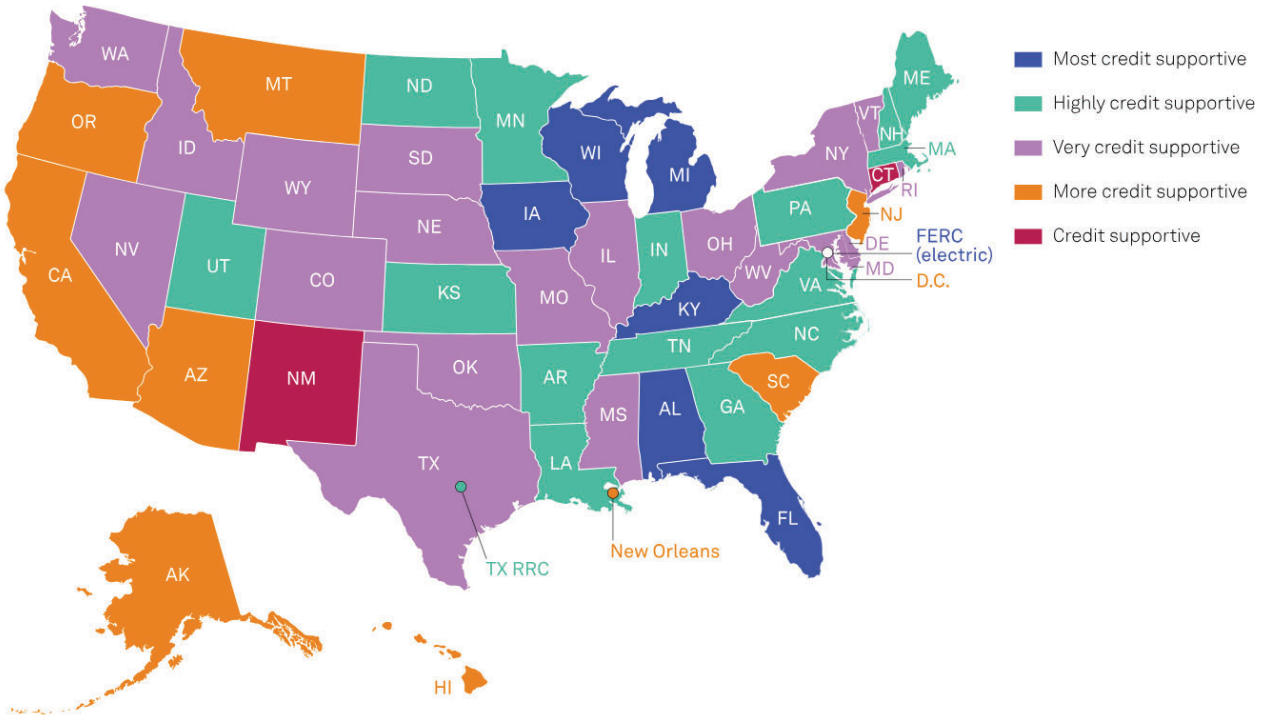
YTD—Year-to-date as of Dec. 15, 2024. Sources: S&P Global Ratings, S&P Global Market Intelligence.

Effective management of regulatory risk will continue. We assess all North America's regulatory jurisdictions as credit supportive or better, reflecting the industry's generally stable and predictable cash flows (see chart 16). Over the past decade much of the industry has implemented regulatory mechanisms such as decoupling, interim rates, capital trackers, formula rate plans, forward test years, muti-year rate case filings, and regulatory riders to significantly improve cash flow stability while minimizing regulatory lag (that is, the timing difference between when a utility incurs costs and when it's recovered from ratepayers).

Chart 16

Regulatory assessment by state

As of November 2024



Source: S&P Global Ratings.

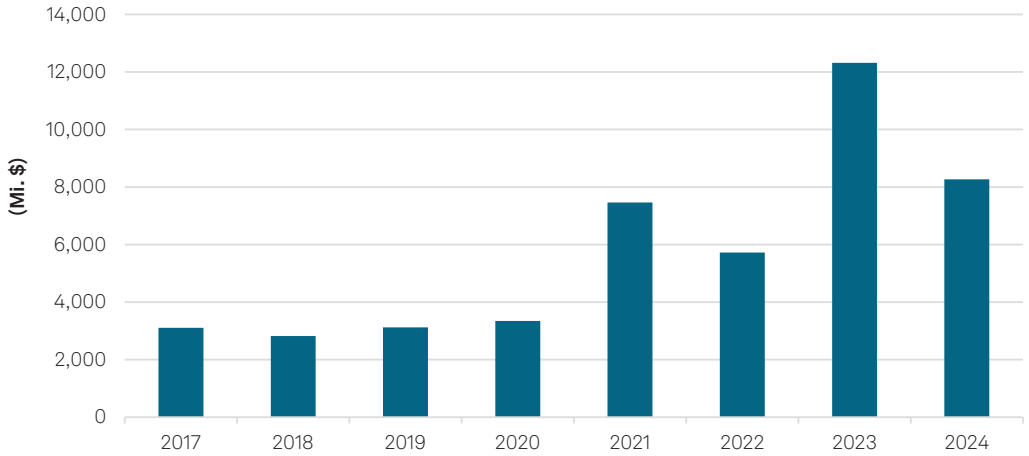
In general, we expect utilities will operate in a regulatory jurisdiction that is supportive of their credit quality by allowing for the full recovery of all their operating and capital costs in a timely manner. We also expect the regulatory jurisdiction will provide a consistent and predictable regulatory framework that results in cash flow stability. Our view of the industry's regulatory constructs supports the industry's mostly investment-grade ratings despite the industry continuing to operate with material cash flow deficits.

Recently, we revised downward our assessment of Connecticut's regulatory construct to credit supportive from more credit supportive. We now expect the state's regulated utilities will be increasingly subject to below-average authorized ROEs, regulatory lag, and an inconsistent ability to earn their lower authorized ROEs. These developments will increase the utilities' cash flow volatility, decrease the stability of their financial performances, and weaken their ability to consistently manage regulatory risk. Other regulatory jurisdictions that we continue to carefully monitor include Arizona, Colorado, District of Columbia, Illinois, Maryland, Michigan, New Mexico, Texas, and West Virginia.

Regulatory rate case order increases have substantially risen over the past four years, reflecting the industry's robust capital spending. Rate case increases for 2021-2024 have increased by more than 2.5x compared to 2017-2020 (see chart 17), and there are more than 100 U.S. rate cases pending, for which utilities are requesting over $16 billion more in revenue. This is in line with our base case that this year's rate case orders will again be robust and most likely in the top three years for rate case order increases.

Chart 17

U.S. rate case orders

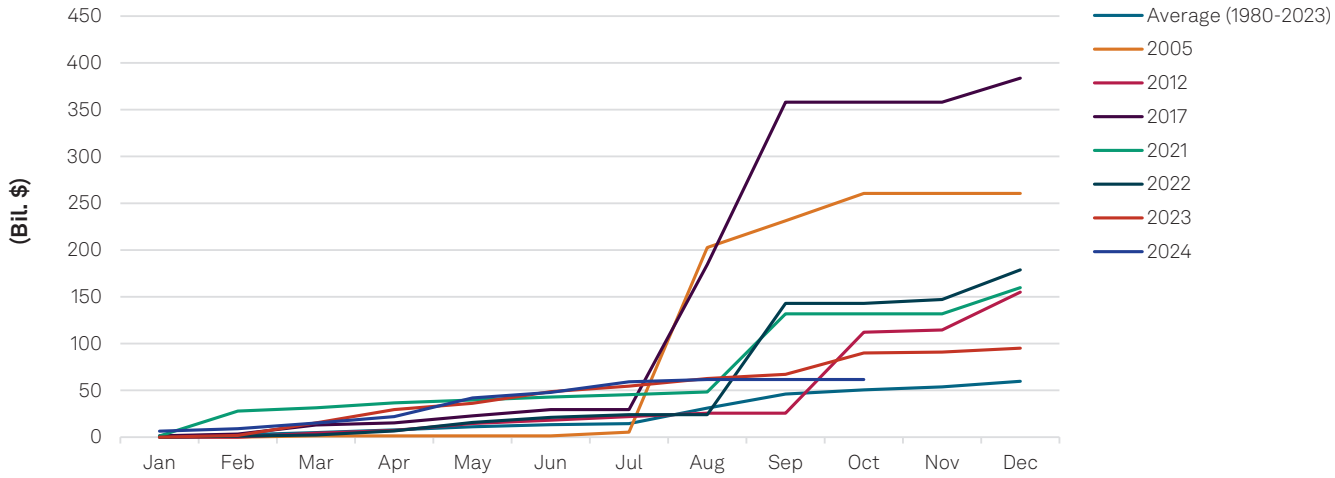


Source: S&P Global Commodity Insights.

Utilities' exposure to physical risks are increasing. According to the National Oceanic and Atmospheric Administration (NOAA), on an inflation-adjusted basis, 2021 and 2022 represent two of the most destructive years for extreme weather events since 1980 (see chart 18). We assume these trends will persist, magnifying physical risks for the utility industry.

Chart 18

U.S. billion-dollar weather disaster year-to-date event cost (CPI-adjusted)



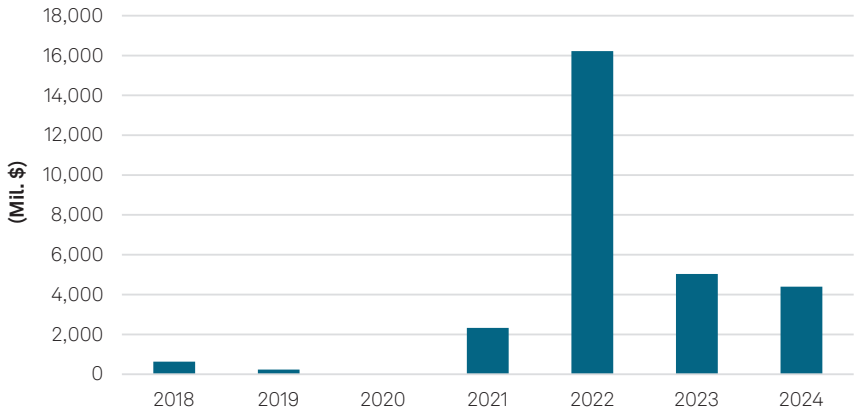
Source: National Ocean and Atmospheric Administration.

Drier, hotter weather has increased the acreage designated as high-fire-risk across the U.S. This is already taking a toll on credit ratings. For example, in 2024 we downgraded parent Xcel Energy Inc. and subsidiary Southwestern Public Service Co. (SPS) because of the scale and severity of the wildfires in the Texas panhandle, which highlights their increasing wildfire exposure. Overall, because of climate change, we expect the industry's wildfire risk will increase.

Securitization increased, which we assess as supportive of credit quality (see chart 19). Securitization allows for the issuance of debt secured by a non-bypassable charge to the customer's bill, allowing the utility to fully recover storm-related costs at a lower interest rate for customers. Because the debt is secured by the high likelihood of customers paying their bills, the associated interest costs are typically lower. We often deconsolidate such debt, resulting in stronger credit measures.

Chart 19

S&P Global Ratings-rated utility-related securitization issuance (2018-2024)



Source: S&P Global Ratings.

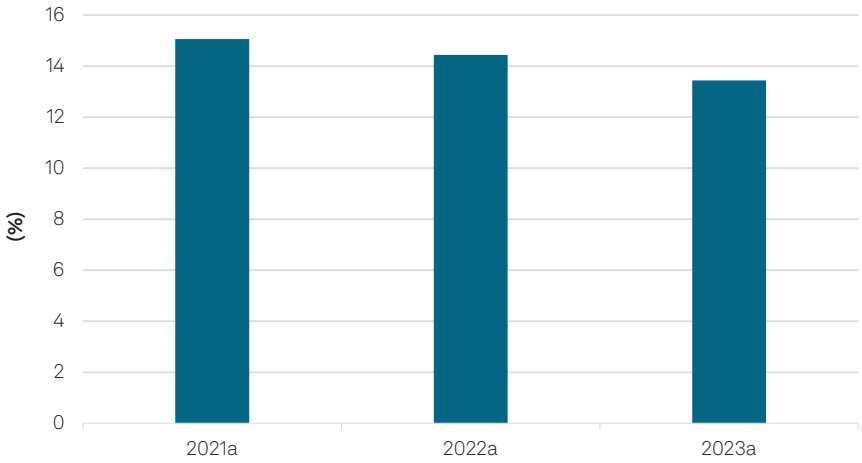
We expect securitization will remain an effective tool that the industry will continue to use. Our base case includes increasing severe natural disasters and weather events as well as continued efforts to decarbonize the energy sector, which sometimes requires securitization to fully recover under-depreciated retiring fossil-fuel generating plants.

Credit metrics and financial policy

We expect rising capital spending and increasing cash flow deficits that are not sufficiently funded in a credit-supportive manner will continue to pressure the industry's financial performance. Its average funds from operations (FFO) to debt was about 15% in 2021 and has gradually fallen to about 13.5%, primarily reflecting rising leverage (see chart 20). Given our expectations for continued increasing capital spending over the next decade, we expect financial performance and credit quality will continue to be pressured.

Chart 20

North American regulated utilities' average FFO to debt



a—Actual. Source: S&P Global Ratings.

Key risks or opportunities around the baseline

1. Wildfire mitigation efforts.

Wildfire risk mitigation, while clearly a credit positive, may not fully address the threats associated with extreme weather events.

2. Data centers and sales growth.

Data center electricity demand will likely boost revenues at North American investor-owned regulated utilities and provide modest support for the industry's credit quality.

3. Managing the customer bill.

The average electric customer bill is about 2% of U.S. median household income, which represents good value for customers relative to other typical household bills. Preserving this value is critical for the industry to maintain credit quality.

Wildfire risk has expanded. Recent events in the Northeast U.S. lead us to believe wildfire risk has spread and now potentially affects nearly every utility across North America. (About 15 years ago, it was primarily limited to just Southern California.)

Wildfire risk is highly negative for credit quality. The scale of potential liabilities, unpredictable nature of exposures, and frequency of events have materially increased wildfire risk for many utility stakeholders. From a credit standpoint, litigation risk is more problematic than risk of damage to infrastructure because it is difficult to predict or quantify and is so far without sufficient mitigation or containment. Also, wildfire-related litigation payments are typically not recoverable in rates or through other regulatory mechanisms, making them more problematic than physical risk.

Additional wildfire risks to credit quality include:

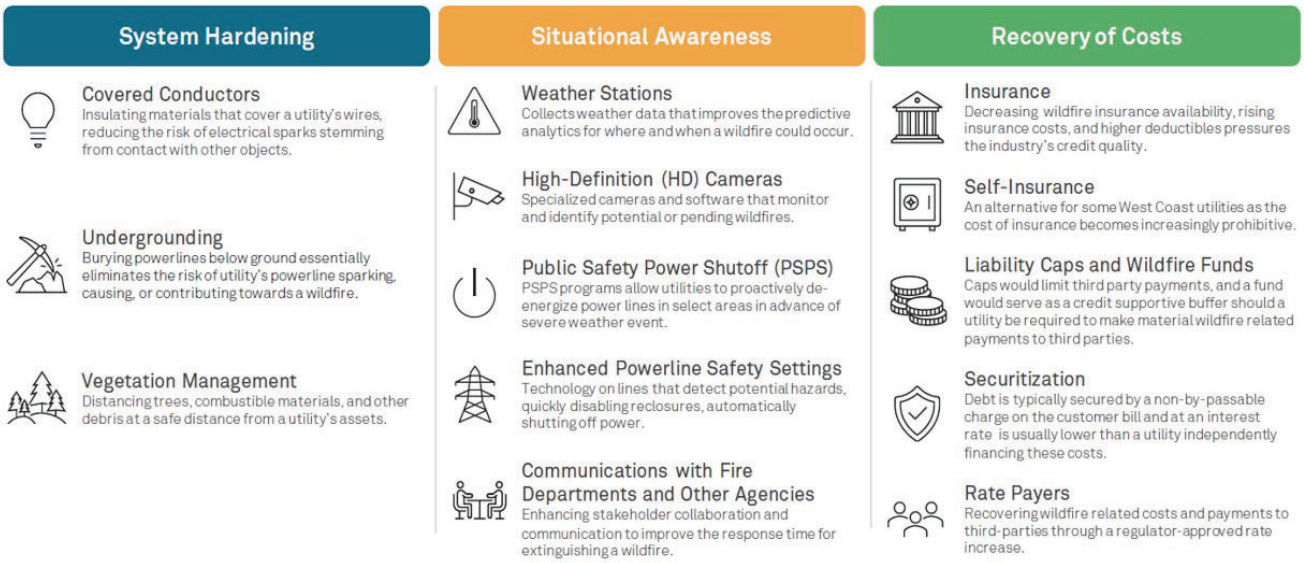
- Insurance is becoming more expensive and less available.
- It only requires a relatively small percentage of damaged or destroyed structures from a wildfire to have a material negative effect on a utility's credit quality.

- The utility industry's relatively high leveraged balance sheets and modest authorized ROEs are not a backstop for wildfire risk.
- Utilities that are impacted by a catastrophic wildfire and material third-party claims typically cannot implement other strategic initiatives.

Mitigation strategies. We expect the industry will develop plans that reduce damages, minimize litigation risk, and expand capabilities for cost recovery from wildfires. We believe the industry will be able to implement much of these strategies over the nearer term because most are not predicated on the development of new technologies or products. That said, because the industry operates in many different service territories and topographies, we expect each utility's mitigation plan will be customized to its unique exposure. Chart 21 represents an array of wildfire mitigation strategies that either have or are being implemented by many utilities across North America.

Chart 21

North American regulated utilities' wildfire mitigation efforts



Source: S&P Global Ratings.

Data centers will likely deliver a return to electricity sales growth. We expect electricity sales will increase at a CAGR of about 1.1%. This reflects our view that systematic and careful planning across the investor-owned utility sector will likely limit its realistic capability to grow at a substantially faster pace. In general, the expansion of utility infrastructure assets is a long-term planning process that requires permitting, siting, and regulatory approvals.

However, even a 1% CAGR for electricity sales will likely prove transformative for the utility industry, which has experienced flat sales growth over the past two decades. In particular, the growing number of data centers will allow the industry to spread its fixed costs over a wider base. We anticipate this will provide some cushion for the industry to effectively manage regulatory risk and maintain credit quality without necessarily requiring that every rate case order is highly supportive of credit quality.

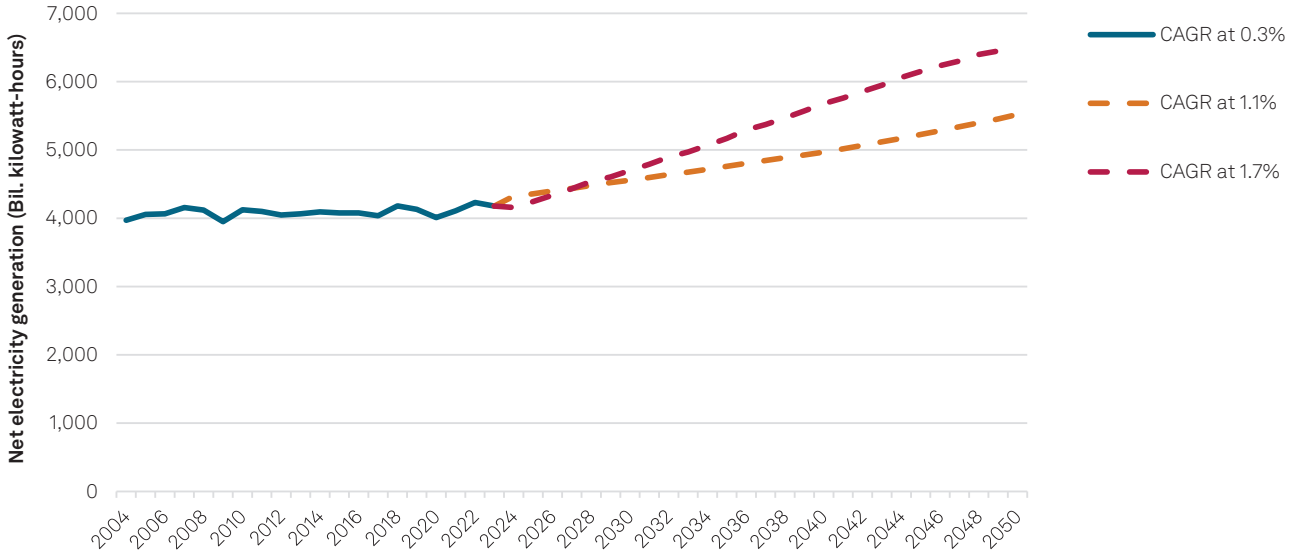
We also expect electric utilities' sales CAGR will be maintained over the longer term (see chart 22), which will support the industry's long-term credit quality. We expect growth in data center numbers will support most of the industry's growth through 2030. In the following decade,

increased onshoring of manufacturing and wider spread adoption of electric vehicles will also support growth.

Chart 22

Growth will be transformative for utilities used to stagnation

Electricity demand: U.S. regulated electric utilities



Data as of June 2024. CAGR—Compound annual growth rate. Sources: U.S. Energy Information Administration (historical and 1.1% CAGR) and S&P Global Commodity Insights (1.7% CAGR).

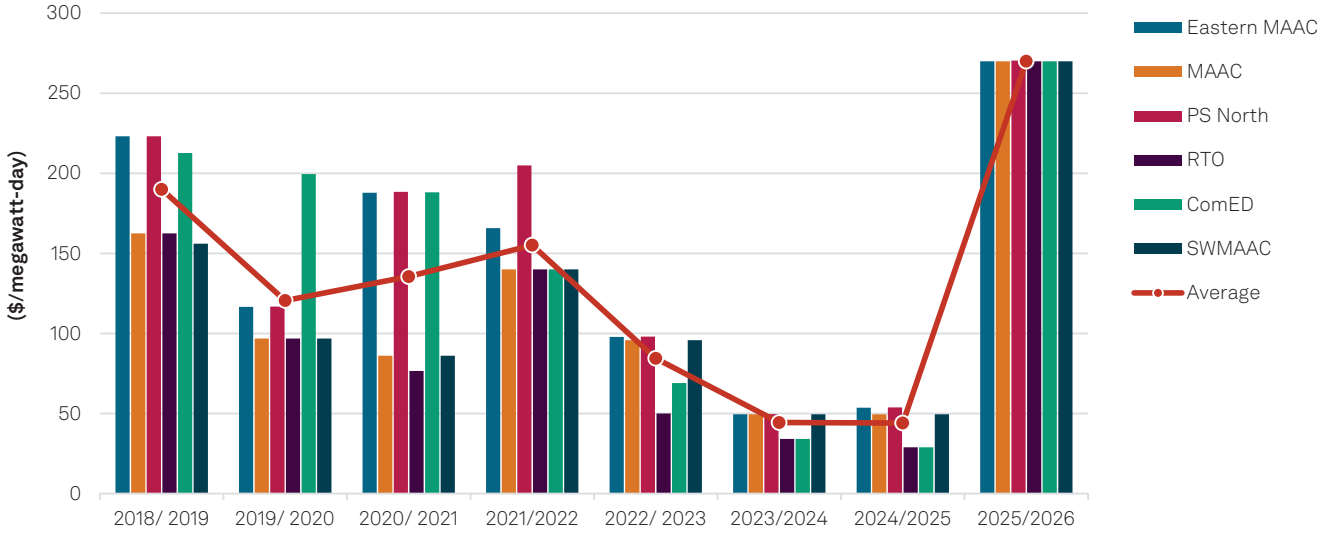
Data center credit risks. The industry must structure rates and contracts to ensure that the new data center customers are paying their share of electricity costs. Meeting the demands of relatively few, but very large, data center customers will require significant capital spending and infrastructure investments. If utilities assign a significant portion of data center-related infrastructure costs to existing residential customers, customer bills would increase. This, in turn, pressures regulators to limit rate case increases, which can negatively affect the industry's ability to effectively manage regulatory risk.

Therefore, we expect the increased capital spending needed to accommodate data center growth will be primarily recovered from data center customers over decades. Such a plan comes with risks. For example, a technological breakthrough that reduces or eliminates the need for data centers could shift the recovery of these long-term infrastructure investments onto residential customers.

Capacity prices. Pennsylvania-New Jersey-Maryland (PJM) Interconnection capacity prices materially increased during its latest capacity auction (see chart 23). These higher prices are directly passed onto customers, significantly increasing the electric utility bill. If these higher prices persist, it will likely result in higher customer complaints, pressuring regulators to limit increases to other areas of the customer bill that could potentially pressure a utility's ability to effectively manage regulatory risk.

Chart 23

PJM capacity auction results



Source: PJM website.

U.S. Environmental Protection Agency (EPA). In 2024 the EPA released final rules aimed at reducing pollution from fossil fuel-fired power plants, which included carbon pollution standards and effluent limitation guidelines and standards for coal-fired power plants. These rules would have increased costs for utilities, specifically regarding the requirement to install carbon capture and sequestration or storage technology on coal-fired power plants intending to operate beyond 2039.

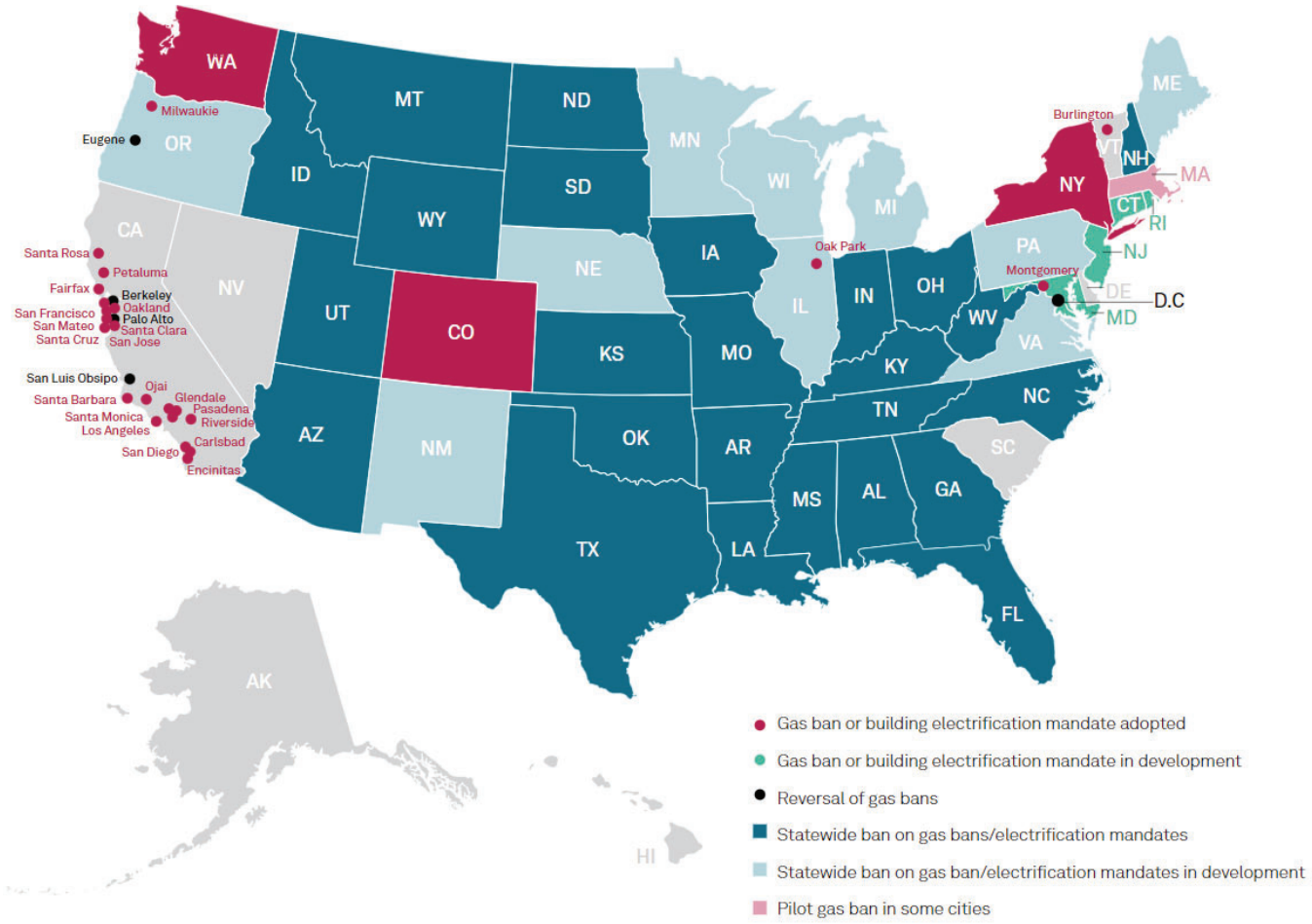
However, we note that the incoming U.S. presidential administration and Republican majority in congress could modify or eliminate these rules. We will monitor executive, legislative, or legal actions that could impact the industry's credit quality.

Full electrification. We expect the longer-term credit quality for some natural gas local distribution companies (LDC) will become increasingly challenging, especially for utilities that operate in warmer climates or whose cities or states have banned new gas connections, severely limiting the growth of natural gas LDCs (see chart 24). We expect this trend will also gradually persist through the passage of local city and town building codes that limit carbon and other emissions.

Offsetting some of this risk is that a majority of states have imposed a ban on the ban of new gas connections. Furthermore, gas LDCs are attempting to reduce their environmental risks by decreasing their carbon footprint through investing in renewable natural gas, blending hydrogen, and initiating various hydrogen infrastructure projects.

Chart 24

Gas bans and electrification mandates



Data as of April 26, 2024. *Municipalities shown on map are a subset of municipalities in the U.S. that have gas ban policies or electric reach codes in place. §Colorado and Burlington mandates target emissions requirements set out in respective laws or regulations. Source: S&P Global Commodity Insights.

Cybersecurity. While cybersecurity breaches against infrastructure assets have been relatively low, we believe the threat of cyberattacks remains high. The 2024 cybersecurity breach against American Water Works Co. Inc. underscores the risks. But the sector has heavily invested to limit this risk. We believe the sector's ongoing vigilance in this area is critical to maintaining credit quality.

Related Research

- Wildfire-Exposed U.S. Investor-Owned Utilities Face Increasing Credit Risks Without Comprehensive Solutions, Nov. 6, 2024
- Data Centers: Rapid Growth Creates Opportunities And Issues, Oct. 30, 2024
- Evolving Risks In North American Corporate Ratings: Climate Change, Oct. 29, 2024
- Data Centers: Welcome Electricity Growth Will Fall Short Of U.S. Data Center Demand, Oct. 22, 2024
- Energy Transition: U.S. Investor-Owned Regulated Electric Utilities Face Hurdles With The EPA's Finalized Rules For Fossil-Fueled Power Plants, Oct. 17, 2024
- North American Utility Regulatory Jurisdictions Update: Some Notable Developments, Sept. 24, 2024

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STATE OF MICHIGAN
DEPARTMENT OF ATTORNEY GENERAL

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DANA NESSEL
ATTORNEY GENERAL

May 7, 2025

Anne M. Uitvlugt
Consumer Energy Company
One Energy Plaza
Jackson, MI 49201

Re: In the matter of **Consumers Energy Company** for authority to increase its rates for the distribution of natural gas and for other relief.
MPSC Case No. U-21806

Dear Ms. Uitvlugt:

Attached are Staff's responses to Consumer Energy Company's second round of discovery to Staff in this case. The responses are being served by e-mail. In providing these responses, Staff does not necessarily concede that the requested information is relevant or material to these proceedings. Staff reserves the right to raise objections to the introduction into evidence, through cross-examination or otherwise, of any material supplied in response to discovery.

Staff intends to supplement a prior response if it becomes aware of a material error in the response or if it becomes aware that there has been a significant change in circumstances that would change the prior response in a material way. Staff does not, however, keep prior responses under continuous review.

Sincerely,

Anna B. Stirling
Assistant Attorney General
Public Service Division
Telephone: (517) 284-8140

Attachment
c: Parties of Record

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **Consumers Energy Company** for authority to increase its rates for the distribution of natural gas and for other relief.

Case No. **U-21806**
(e-file paperless)

_____/

MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S ANSWER TO CONSUMERS ENERGY COMPANY'S SECOND DISCOVERY REQUEST

Respectfully submitted,

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

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Telephone: (517) 284-8140

DATED: May 7, 2025

MPSC Staff's Answer to the Company's Second Discovery Request
MPSC Case No. U-21806
May 7, 2025

Question:

21806-CE-ST-0004: Refer to the box at the bottom of Mr. Megginson's Exhibit S-4, Schedule D-2. Please provide support for the 2025 and 2026 projected credit spread of 1.00%.

Answer:

The Company's last 30-year debt issuance was in August 2022, with a credit spread of 125 basis points. The Company's recent $700 million debt issuances in August 2024 was a 6-year issuance at a credit spread of 68 basis points. The Company's January 2024, 5-year issuance was at a credit spread of 73 basis points. The Company averaged an 83 basis points spread for its 2023 debt issuances. Thus, a reasonable credit spread is somewhere between 75-125 basis points. Staff provides a 100 basis-point credit spread in its long-term debt cost rate projections in this case.

Respondent: Kirk Meggison

MPSC Staff's Answer to the Company's Second Discovery Request
MPSC Case No. U-21806
May 7, 2025

Question:

21806-CE-ST-0005: Refer to page 10, lines 5 through 13 of Mr. Megginson's direct testimony which refers to a revenue decoupling mechanism and several gas infrastructure improvement and replacement programs with surcharge payment mechanisms in place at Consumers Energy:

i. Please identify the MPSC case number which authorizes the revenue decoupling mechanism currently in place as referenced in Mr. Megginson's testimony.

ii. Please individually list the "several gas infrastructure improvement and replacement programs" the Company has in place as referenced in Mr. Megginson's testimony along with the associated MPSC case numbers.

Answer:

As Staff explained on page 7, lines 13-16 of Mr. Megginson's testimony on the Company's enhanced infrastructure replacement program (EIRP) was authorized by the Commission in Case No. U-20322. The Company also provided a January 29, 2025 audit response (U21806-SA-CE-101), with respect to the Company's riders and other revenue recovery mechanisms currently in place in Consumers' gas division. The Company responded that it currently has a Gas Cost Recovery mechanism as well as an Energy Waste mechanism in place. Staff also provided the Company's response in Case No. U-21148 to the Company's Gas Utility - Regulatory Assets & Liabilities as Exhibit S-4, Schedule D-6, page 1 of 2.

Respondent: Kirk Meggison

MPSC Staff's Answer to the Company's Second Discovery Request
MPSC Case No. U-21806
May 7, 2025

The Company's revenue decoupling mechanism (RDM) was approved by the Commission in Case No. U-20322 and reapproved in Case No. U-20650. The Company requested an updated RDM in December 2021 in its gas rate case, Case No. U-21148, which was approved by the Commission and took effect on October 1, 2023. In the Company's December 2022 gas rate case, Case No. U-21308, the Company did not request an updated RDM because the Company noted that the RDM was discovered to be immaterial given the cadence of filing annual rate cases. (See audit response U21308-SA-CE-128-Partial-Wehner). Thus, the RDM may have discontinued sometime in 2024.

Respondent: Kirk Meggison

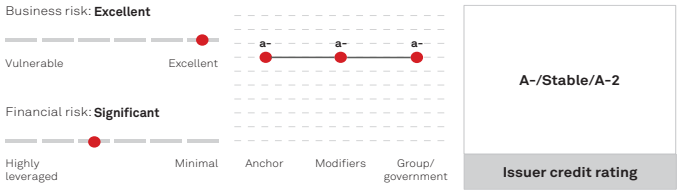
S&P Global
Ratings

RatingsDirect®

Consumers Energy Co.

August 20, 2024

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Monopolistic vertically integrated electric utility and gas distribution utility operations.	Lack of operating diversity that makes the company largely depend on Michigan regulators to sustain its credit quality.
Favorable regulatory construct in Michigan.	Energy transition risks due to its dependence on natural gas and coal-fired generation (about 75% of electricity generated or purchased in 2023), partially mitigated by a plan to retire coal in 2025.
Large customer base of 1.9 million electric and 1.8 million gas customers.	Negative discretionary cash flow, reflecting robust capital spending, which indicates external funding needs.
Insulated subsidiary of its parent, CMS Energy Corp., allowing us to rate it one notch above the parent.	Susceptibility to adverse weather events, including winter storms and convective storms.
	Exposure to cyclical commercial and industrial customers, which account for about 45%-50% of electric utility revenues and 20%-25% of gas utility revenues.

We expect Consumers Energy Co. (CE) to continue to effectively manage its regulatory risk. We believe Michigan's regulatory construct is above average compared with peers because of the benefit of a streamlined 10-month rate case process. Other constructive rate mechanisms include the use of forward test-years, power supply cost rider adjustments, and natural gas

cost rider adjustments. These mechanisms help the company earn its allowed return on equity (ROE) and minimize regulatory lag.

CE is in the middle of an electric rate case and just received a settlement approval in its recent gas rate case. The company filed for a $325 million electric rate increase based on a 10.25% ROE in May and reached a settlement with various intervenors and received an order from the Michigan Public Service Commission (MPSC) for a $35 million gas rate increase based on a 9.90% ROE. The gas rate increase granted was about only a quarter of the rate increase requested. However, this difference was partially because the commission authorized bill credits of $27.5 million per year over four years related to the gain on the sale of CE's appliance service plan business, which happened after and was not a part of the company's case filing.

Consumers Energy Co. rate case details

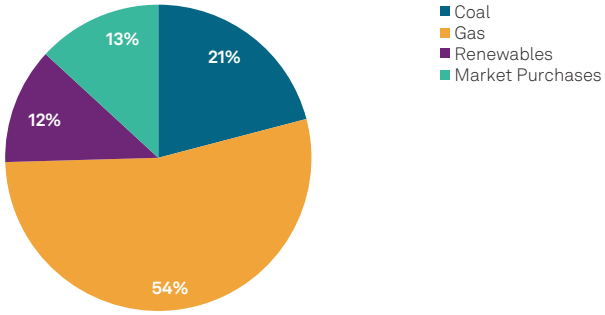
	Electric rate case		Gas rate case	
	Present case: requested by company 5/31/2024	Previous case: authorized by MPSC 3/1/2024	Authorized by MPSC 7/23/2024	Requested by company 12/15/2023
Rate change amount (mil. $)	325	92.0	35.0	136.0
Rate base (mil. $)	15,571.5	13,669	10,850*	10,970
Rate base valuation method	Average	Average	Average	Average
Return on equity (%)	10.25	9.90	9.90	10.25
Common equity to total capital (%)	42.36	41.13	41.48*	42.73
Rate of return (%)	6.21	5.86	5.93*	6.20
Rate case test year end date	2/28/2026	2/28/2025	9/30/2025	9/30/2025

*Company assumption under settlement. Source: S&P CapitalIQ Pro. MPSC--Michigan Public Service Commission.

The company's elevated capital spending plan prioritizes infrastructure upgrades, and its energy transition plans. Over the next five years, CE plans to spend about $17 billion to maintain and upgrade its gas infrastructure and electric distribution systems and reduce its carbon emissions. The capital plan includes investment of about $6.3 billion in the gas segment and about $10.7 billion in electric (of which, about two thirds are dedicated to distribution-related spending). The company also intends to reduce its carbon exposure in line with its Integrated Resource Plan (IRP), which the MPSC approved in June 2022. The plan includes a goal to reach net-zero carbon emission by 2040 and a goal to retire CE's owned coal-fired generation plants in 2025. Furthermore, the company's IRP targets a gradual reduction in its gas-fired generation dependence after 2025, as well as meeting 90% of its customer needs with clean energy sources by 2040. The company also announced a net-zero greenhouse gas emissions target by 2050 and a zero methane emissions target by 2030 for its gas distribution system.

Consumers Energy Co.

CE's 2023 generated and purchased electricity supply by source



Source: Company filings.

The company's credit metrics were weak in 2023, largely because of weather-related issues. Mild weather impaired sales for the company's gas operations, and the company saw heightened winter and convective storm activities. While the company has effectively recovered storm costs in past rate case proceedings, it has not been able to defer storm costs into regulatory assets, which introduced regulatory lag.

A portion of CE's service territory has a relatively high wildfire risk classification from the Federal Emergency Management Agency (FEMA). This area is contiguous and has a population of about 10,000-15,000 people, 7,000-9,000 housing units, of which about 40%-60% are occupied, and median home values if $100,000-$150,000 according to U.S. Census data. Part of the company's capital spending plan is focused on smart electric systems and anticipates pursuing further undergrounding pilots, with the potential to underground up to 400 miles of electric lines per year, starting in 2027, to address some of its climate-related risks. While CE has not been found culpable for any wildfires in its service territory and is not currently party to any such litigation, we will continue to monitor the company's ability to effectively manage its risks associated with adverse weather events.

We expect CE's credit measures to remain within the significant financial risk profile category. Throughout our base-case scenario, we expect funds from operations (FFO) to debt of 17%-19%.

Outlook

The stable rating outlook on CE reflects our expectation that management will focus on its core utility operations and reach constructive regulatory outcomes to avoid increasing business risk. We expect CE will maintain stand-alone financial measures consistent with the middle of the range for its financial risk profile category, specifically FFO to debt of 17%-19%.

Downside scenario

We could lower our rating on CE if:

- The stand-alone financial measures weaken such that FFO to debt weakens to consistently below 15%; or

- We lower our rating on parent CMS Energy.

Upside scenario

Although less likely, we could raise our rating on CE if we raise our rating on CMS Energy and CE's stand-alone financial measures improve, reflecting FFO to debt consistently above 20%.

Our Base-Case Scenario

Assumptions

- Consistent rate case filings and use of existing regulatory mechanisms;
- Elevated capital spending over the forecast period averaging $2.8 billion-$3.0 billion annually;
- Annual dividends averaging about $1 billion-$1.1 billion annually;
- All debt maturities refinanced; and
- Continued negative discretionary cash flow financed in a balanced manner to support the regulated capital structure.

Key metrics

Consumers Energy Co.--Forecast summary

Period ending	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026	Dec-31-2027
(Mil. $)	2020a	2021a	2022a	2023a	2024e	2025f	2026f	2027f
Revenue	6,155	6,987	8,117	7,129	8,230	8,803	9,333	9,879
EBITDA (reported)	2,244	2,252	2,321	2,405	2,795	3,081	3,337	3,582
Plus: Operating lease adjustment (OLA) rent	9	8	6	6	6	6	6	6
Plus/(less): Other	139	146	70	74	(39)	(40)	(40)	(22)
EBITDA	2,392	2,406	2,397	2,485	2,762	3,047	3,303	3,566
Less: Cash interest paid	(373)	(376)	(343)	(454)	(480)	(559)	(620)	(684)
Less: Cash taxes paid	(51)	10	2	(31)	(112)	3	1	(9)
Plus/(less): Other	--	--	--	--	--	--	--	--
Funds from operations (FFO)	1,968	2,040	2,057	2,000	2,169	2,491	2,685	2,873
EBIT	1,268	1,246	1,262	1,349	1,625	1,826	1,993	2,172
Interest expense	393	381	375	496	512	591	652	716
Cash flow from operations (CFO)	1,265	2,013	984	2,415	2,316	2,529	2,662	2,802
Capital expenditure (capex)	2,254	2,136	2,275	2,279	2,892	3,318	2,897	2,890
Free operating cash flow (FOCF)	(989)	(124)	(1,291)	136	(576)	(789)	(235)	(88)
Dividends	639	723	770	696	865	951	1,047	1,129
Share repurchases (reported)	--	--	--	--	--	--	--	--
Discretionary cash flow (DCF)	(1,628)	(847)	(2,061)	(560)	(1,441)	(1,740)	(1,282)	(1,217)
Debt (reported)	8,429	8,810	10,287	11,285	12,331	13,437	14,319	15,172

Consumers Energy Co.

Consumers Energy Co.--Forecast summary

Plus: Lease liabilities debt	88	74	81	41	26	19	15	12
Plus: Pension and other postretirement debt	--	--	--	--	--	--	--	--
Less: Accessible cash and liquid Investments	(20)	(22)	(43)	(35)	(100)	(100)	(100)	(100)
Plus/(less): Other	616	553	699	80	167	282	404	532
Debt	9,113	9,415	11,024	11,371	12,423	13,637	14,638	15,616
Equity	8,556	9,261	10,137	10,782	11,564	12,735	13,667	14,580
Adjusted ratios								
Debt/EBITDA (x)	3.8	3.9	4.6	4.6	4.5	4.5	4.4	4.4
FFO/debt (%)	21.6	21.7	18.7	17.6	17.5	18.3	18.3	18.4
FFO cash interest coverage (x)	6.3	6.4	7.0	5.4	5.5	5.5	5.3	5.2
EBITDA interest coverage (x)	6.1	6.3	6.4	5.0	5.4	5.2	5.1	5.0
CFO/debt (%)	13.9	21.4	8.9	21.2	18.6	18.5	18.2	17.9
FOCF/debt (%)	(10.9)	(1.3)	(11.7)	1.2	(4.6)	(5.8)	(1.6)	(0.6)
DCF/debt (%)	(17.9)	(9.0)	(18.7)	(4.9)	(11.6)	(12.8)	(8.8)	(7.8)
Annual revenue growth (%)	(2.9)	13.5	16.2	(12.2)	15.4	7.0	6.0	5.9
EBITDA margin (%)	38.9	34.4	29.5	34.9	33.6	34.6	35.4	36.1
Return on capital (%)	7.5	6.9	6.3	6.2	7.0	7.3	7.3	7.4
Debt/debt and equity (%)	51.6	50.4	52.1	51.3	51.8	51.7	51.7	51.7
Debt fixed-charge coverage (x)	6.1	6.3	6.4	5.0	5.4	5.2	5.1	5.0

All figures are adjusted by S&P Global Ratings, unless stated as reported. a--Actual. e--Estimate. f--Forecast. $--U.S. dollar.

Company Description

CE is a subsidiary of CMS Energy and operates as an electric and gas utility serving about 1.9 million electric and 1.8 million natural gas million customers in Michigan. CE's electric business operates as a vertically integrated utility that generates, distributes, and sells electricity. The electric utility sources about 40%-50% of its generation from purchased power, rather than from its own plants. The company also sells, stores, and transports natural gas. It is based in Jackson, Mich. CE contributes to about 95% of CMS' EBITDA.

Peer Comparison

Consumers Energy Co.--Peer Comparisons

	Consumers Energy Co.	DTE Electric Co.	Wisconsin Power & Light Co.	Wisconsin Electric Power Co.	Consolidated Edison Co. of New York Inc.
Foreign currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2	A-/Stable/A-2	A/Negative/A-1	A-/Stable/A-2	A-/Stable/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2023-12-31	2023-12-31	2023-12-31	2023-12-31	2023-12-31

Consumers Energy Co.

Consumers Energy Co.--Peer Comparisons

Mil.	$	$	$	$	$
Revenue	7,129	5,729	1,827	4,045	13,476
EBITDA	2,485	2,715	760	1,716	4,232
Funds from operations (FFO)	2,000	2,282	544	1,056	3,276
Interest	496	623	152	383	1,032
Cash interest paid	454	418	166	561	983
Operating cash flow (OCF)	2,415	1,534	558	1,028	2,250
Capital expenditure	2,279	3,076	999	1,183	4,010
Free operating cash flow (FOCF)	136	(1,542)	(441)	(155)	(1,760)
Discretionary cash flow (DCF)	(560)	(2,544)	(625)	(524)	(2,816)
Cash and short-term investments	35	15	7	6	1,138
Gross available cash	35	15	7	6	1,138
Debt	11,371	12,009	3,748	5,657	22,824
Equity	10,782	10,224	3,897	5,068	19,146
EBITDA margin (%)	34.9	47.4	41.6	42.4	31.4
Return on capital (%)	6.2	6.8	7.6	12.2	5.6
EBITDA interest coverage (x)	5.0	4.4	5.0	4.5	4.1
FFO cash interest coverage (x)	5.4	6.5	4.3	2.9	4.3
Debt/EBITDA (x)	4.6	4.4	4.9	3.3	5.4
FFO/debt (%)	17.6	19.0	14.5	18.7	14.4
OCF/debt (%)	21.2	12.8	14.9	18.2	9.9
FOCF/debt (%)	1.2	(12.8)	(11.8)	(2.7)	(7.7)
DCF/debt (%)	(4.9)	(21.2)	(16.7)	(9.3)	(12.3)

Business Risk

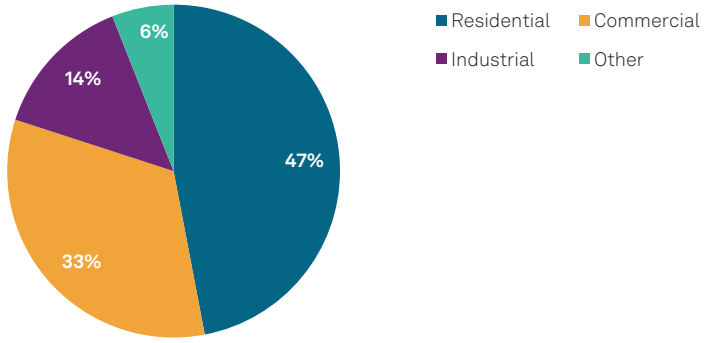
Our assessment of CE's business risk profile reflects the company's monopolistic electric and natural gas utility operations and effective management of regulatory risk. The MPSC regulates CE, and we view the regulatory environment in Michigan as above average compared with peers. This is demonstrated through the company's use of forward-looking test years and a streamlined 10-month rate case process. Furthermore, CE benefits from other constructive rate mechanisms, such as the Power Supply Cost Recovery adjustment rider, and the Gas Cost Recovery adjustment rider.

In 2023, the state also passed a law that allows electric utilities in the state to earn a return equal to their pre-tax weighted average cost of capital on payments made under new purchased-power agreements. These constructive rate mechanisms enable CE to generally earn its allowed ROE and minimize regulatory lag.

The company actively manages its gas supply to reduce the effects of price volatility and to support its gas system operations by injecting natural gas into storage during the summer months for use during the winter months. During 2023, 45% of the natural gas supplied to all customers during the winter months came from storage. Additionally, CE's large customer base

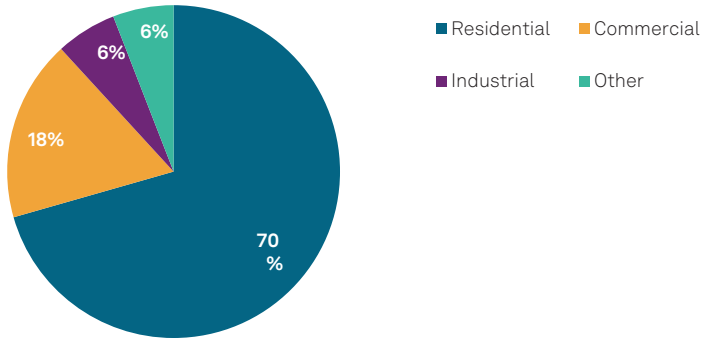
of about 1.9 million electric customers and about 1.8 million natural gas customers throughout Michigan bolsters the company's business risk profile. This said, the company is exposed to cyclical commercial and industrial customers for its electric operations, which contribute about 45%-50% of the company's electric revenues.

CE's 2023 electrical revenue by customer class



Source: Company filings.

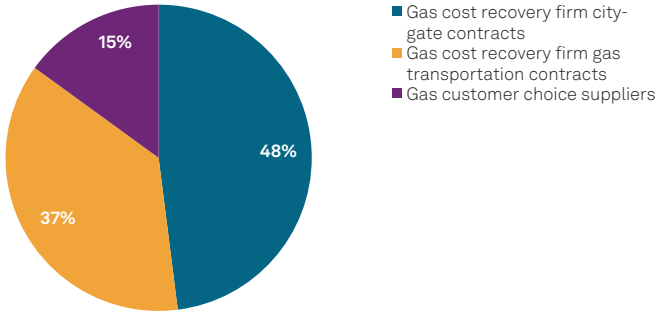
CE's 2023 gas revenue by customer class



Source: Company filings

Consumers Energy Co.

CE's 2023 gas supply sources



Source: Company filings

Financial Risk

We assess CE's financial measures using our medial volatility table, reflecting the company's lower-risk regulated electric and gas utility operations and its effective management of regulatory risk. Under our base-case scenario, we expect:

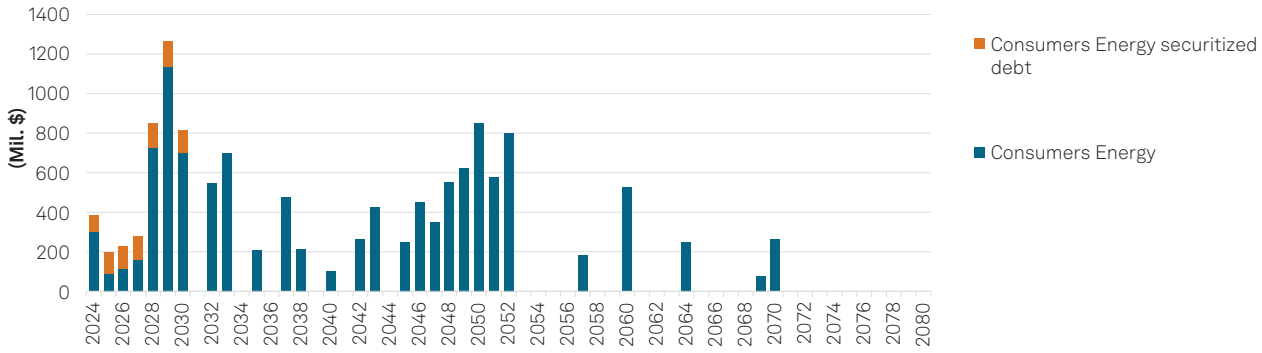
- Elevated capital spending averaging $2.8 billion-$3.0 billion annually over the forecast period;
- Dividends averaging $1 billion-$1.1 billion annually;
- Equity injections by the parent to maintain the company's capital structure;
- Continued use of existing regulatory mechanisms;
- Negative discretionary cash flow; and
- The refinancing of all debt maturities.

As such, we anticipate financial measures to be consistent with the middle of the range for the significant financial risk category. Specifically, we forecast FFO to debt of 17%-19%.

Consumers Energy Co.

Debt maturities

Consumers Energy debt maturities



Source: Company filings and S&P Global Ratings.

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Consumers Energy Co.--Financial Summary

Period ending	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023
Reporting period	2018a	2019a	2020a	2021a	2022a	2023a
Display currency (mil.)	$	$	$	$	$	$
Revenues	6,430	6,341	6,155	6,987	8,117	7,129
EBITDA	2,152	2,252	2,392	2,406	2,397	2,485
Funds from operations (FFO)	1,665	1,823	1,968	2,040	2,057	2,000
Interest expense	355	335	393	381	375	496
Cash interest paid	331	296	373	376	343	454
Operating cash flow (OCF)	1,533	1,688	1,265	2,013	984	2,415
Capital expenditure	1,920	2,191	2,254	2,136	2,275	2,279
Free operating cash flow (FOCF)	(387)	(502)	(989)	(124)	(1,291)	136
Discretionary cash flow (DCF)	(918)	(1,094)	(1,628)	(847)	(2,061)	(560)
Cash and short-term investments	39	11	20	22	43	35
Gross available cash	39	11	20	22	43	35
Debt	7,774	8,238	9,113	9,415	11,024	11,371
Common equity	6,920	7,737	8,556	9,261	10,137	10,782
Adjusted ratios						
EBITDA margin (%)	33.5	35.5	38.9	34.4	29.5	34.9
Return on capital (%)	7.9	7.7	7.5	6.9	6.3	6.2
EBITDA interest coverage (x)	6.1	6.7	6.1	6.3	6.4	5.0
FFO cash interest coverage (x)	6.0	7.2	6.3	6.4	7.0	5.4
Debt/EBITDA (x)	3.6	3.7	3.8	3.9	4.6	4.6
FFO/debt (%)	21.4	22.1	21.6	21.7	18.7	17.6
OCF/debt (%)	19.7	20.5	13.9	21.4	8.9	21.2

Consumers Energy Co.

Consumers Energy Co.--Financial Summary

FOCF/debt (%)	(5.0)	(6.1)	(10.9)	(1.3)	(11.7)	1.2
DCF/debt (%)	(11.8)	(13.3)	(17.9)	(9.0)	(18.7)	(4.9)

Reconciliation Of Consumers Energy Co. Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2023									
Company reported amounts	11,285	10,800	7,166	2,405	1,268	448	2,485	2,430	697	2,248
Cash taxes paid	-	-	-	-	-	-	(31)	-	-	-
Cash interest paid	-	-	-	-	-	-	(438)	-	-	-
Lease liabilities	41	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	6	1	1	(1)	5	-	-
Intermediate hybrids (equity)	19	(19)	-	-	-	1	(1)	(1)	(1)	-
Accessible cash and liquid investments	(35)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	3	(3)	(3)	-	(3)
Share-based compensation expense	-	-	-	26	-	-	-	-	-	-
Securitized stranded costs	(787)	-	(37)	(37)	(8)	(8)	8	(29)	-	-
Power purchase agreements	358	-	-	53	19	19	(19)	34	-	34
Asset-retirement obligations	584	-	-	32	32	32	-	-	-	-
Nonoperating income (expense)	-	-	-	-	37	-	-	-	-	-
Reclassification of interest and dividend cash flows	-	-	-	-	-	-	-	(21)	-	-
Debt: other	(93)	-	-	-	-	-	-	-	-	-
Total adjustments	86	(19)	(37)	80	81	48	(485)	(15)	(1)	31
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	11,371	10,782	7,129	2,485	1,349	496	2,000	2,415	696	2,279

Liquidity

We assess CE's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and that its sources cover uses even if forecast consolidated EBITDA declines 10%. We believe the supportive regulatory framework provides manageable cash flow stability for the company even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity.

In addition, CE can absorb high-impact, low-probability events, in our view, as the company maintains about $1.1 billion in committed credit facilities through 2027, another $250 million in committed credit facilities through November 2025, and can likely lower its capital spending (averaging $2.8 billion-$3.0 billion annually) during stressful periods, indicating a limited need for refinancing under such conditions. CE can borrow $500 million from the parent CMS Energy as per its renewed credit agreement in December 2023.

Furthermore, our assessment reflects the company's prudent risk management and sound relationships with its banking group. Overall, we believe that the company can withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. The company has around $200 million of long-term debt maturities in 2025, and we expect the company to proactively address these maturities well in advance of their scheduled due dates.

Principal liquidity sources

- Cash FFO of about $2.4 billion;
- Credit facilities of about $1.3 billion;
- Working capital inflows of about $70 million; and
- Available cash of about $1.3 billion following the company's recent debt issuance.

Principal liquidity uses

- Debt maturities of about $772 million over the next 12 months;
- Estimated maintenance capital spending of about $2.7 billion; and
- Dividends of about $900 million.

Covenant Analysis

Requirements

CE's credit agreements contain a covenant for CE to maintain debt to capitalization below 65%.

Compliance expectations

In our base-case scenario, we expect CE to remain compliant with this covenant and have sufficient headroom.

Environmental, Social, And Governance

Environmental factors are a negative consideration in our credit rating analysis of CE. The company's use of fossil fuel generation sources exposes it to heightened energy transition risks. Its generation portfolio's capacity comprises about 36% natural gas, 20% coal, 17%

hydroelectric, 17% oil and gas, and 9% wind and solar as of Dec. 31, 2023. The company's accelerated coal retirement plan for its utility slightly mitigates this risk. It includes a goal to be coal-free in 2025 and have 90% of its utility's capacity portfolio sourced from clean energy resources by 2040.

Furthermore, the company has experienced heightened winter and convective storm activities in recent years. While the company has effectively recovered storm costs in past rate case proceedings, it has not been able to defer storm costs into regulatory assets, which could introduce regulatory lag especially if costs are outsized.

While CMS has not been found culpable for any wildfires in its service territory and is not currently party to any litigation concerning these matters, a portion of its service territory has a relatively high wildfire risk classification from FEMA. This area is contiguous and has a population of about 10,000-15,000 inhabitants, 7,000-9,000 housing units, of which about 40%-60% are occupied, and median home values of $100,000-$150,000 according to U.S. Census data. Part of the company's capital spending plan is focused on smart electric systems and anticipates pursuing further undergrounding pilots, with the potential to underground up to 400 miles of electric lines per year starting in 2027. We will continue to monitor the company's ability to effectively manage its risks associated with adverse weather events.

Group Influence

Under our group rating methodology, we consider CMS Energy to be the parent of the group with a group credit profile (GCP) of 'bbb+'. We assess CE as a core subsidiary of CMS Energy largely because we view the utility as integral to the group's identity, highly unlikely to be sold and having a strong commitment from management, given the company's emphasis on maintaining the size of the regulated utility operations relative to the nonutility businesses.

Given CE's stand-alone credit profile, and because CE is operationally separate and maintains sufficient insulating measures, we rate the utility one notch above the GCP. Some of the key insulating measures are:

- CE is a separate and stand-alone legal entity that functions independently (both financially and operationally), files its own rate cases, and is independently regulated by MPSC;
- CE has its own records and books, including stand-alone audited financial statements;
- The utility has its own funding arrangements, including issuing its own long-term debt, and it has a separate committed credit facility to cover its short-term funding needs;
- CE does not comingle funds, assets, or cash flow with parent CMS Energy or its other subsidiaries, and it does not participate in a money pool;
- We believe there is a strong economic basis for CMS Energy to preserve CE's credit strength, reflecting CE's low-risk, profitable, and regulated utility business model. CE is also a significant portion of CMS Energy, accounting for about 95% of the consolidated company; and
- There are no cross-default provisions between parent CMS Energy and CE that could directly lead to a default at the utility.

Issue Ratings--Subordination Risk Analysis

Capital structure

CE's capital structure consists of about $12.5 billion of long-term debt, including about $11.7 billion in first-mortgage bonds (FMBs), $787 million of securitized debt (all of which is deconsolidated from our credit metrics), and about $110 million of tax-exempt revenue bonds.

Analytical conclusions

We rate the company's senior unsecured debt 'A-', in-line with the long-term issuer credit rating on CE as the rated issuances are senior unsecured debt issued by a qualifying investment grade utility as per our criteria.

We base our 'A-2' short-term rating on our 'A-' issuer credit rating.

Issue Ratings--Recovery Analysis

Key analytical factors

- We assign recovery ratings to FMBs issued by U.S. utilities, which can result in issue ratings being notched above an issuer credit rating on a utility, depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of secured utility bonds that qualify for a recovery rating as defined in our criteria.
- CE's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Rating Component Scores

Foreign currency issuer credit rating	A-/Stable/A-2
Local currency issuer credit rating	A-/Stable/A-2
Business risk	Excellent
Country risk	Very Low
Industry risk	Very Low
Competitive position	Excellent
Financial risk	Significant
Cash flow/leverage	Significant
Anchor	a-
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	a-
Group credit profile	bbb+
Entity status within group	Insulated (no impact on SACP)

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Hybrid Capital: Methodology And Assumptions, March 2, 2022
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings Detail (as of August 20, 2024)*	
Consumers Energy Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A
Issuer Credit Ratings History	
30-Oct-2019	A-/Stable/A-2
03-Dec-2014	BBB+/Stable/A-2
11-Sep-2014	BBB/Positive/A-2
Related Entities	
CMS Energy Corp.	
Issuer Credit Rating	BBB+/Stable/A-2
Junior Subordinated	BBB-
Preferred Stock	BBB-
Senior Unsecured	BBB

Consumers Energy Co.

Ratings Detail (as of August 20, 2024)*

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

Consumers Energy Co.

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CREDIT OPINION
31 May 2024

Update

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RATINGS

Consumers Energy Company

Domicile	Jackson, Michigan, United States
Long Term Rating	(P)A3
Type	Senior Unsec. Shelf - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Consumers Energy Company

Update to credit analysis

Summary

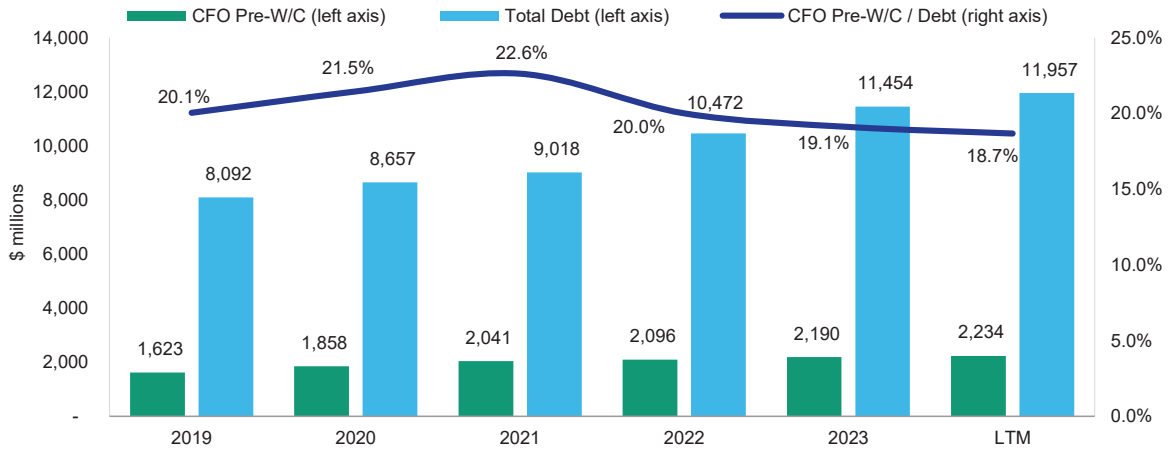
Consumers Energy Company's (Consumers Energy) credit profile reflects its business risk as a vertically integrated electric and gas utility operating in the credit supportive regulatory environment of Michigan. We expect the utility to maintain a stable financial profile with cash flow from operations before changes in working capital (CFO pre-WC) to debt averaging around 20-21%, including an adjustment to exclude securitization debt, over the next 2-3 years. At the end of the latest twelve month (LTM) period ending 31 March 2024, Consumers Energy's CFO pre-WC to debt ratio was 20%, including the adjustment to exclude securitization bonds. The company will continue to execute its robust capital investment plan and have an active regulatory calendar over this period. Based on the Michigan regulatory framework, we expect the utility to recover its investment costs on a timely basis and to earn an appropriate return on its investments.

Consumers Energy's stand-alone financial performance has historically been affected by the significant debt at its parent company CMS Energy Corporation (CMS, Baa2 stable). However, CMS has made notable progress in reducing the percentage of parent debt in its capital structure in recent years. We now estimate that the percentage of parent debt will remain below 25% of total consolidated debt. All of Consumer Energy's outstanding debt obligations are secured.

Recent development

In November 2023, Michigan enacted a new energy law (2023 Energy Law), which raised the state's renewable energy standard while providing additional authority to the Michigan Public Service Commission (MPSC). Consumer Energy's operations are under the purview of MPSC. In general, we view this development to be constructive because the utilities in the state will now outline a renewable energy plan with greater transparency, and the MPSC will have an expanded scope of consideration for various factors influencing Consumers Energy' plan to decarbonize.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt



When we adjust the total debt to exclude securitization debt, Consumers Energy's CFO pre-WC/debt would be 20.3%, 20.4% and 20.0% in 2022, 2023 and LTM ending 31 March 2024, respectively.
Source: Moody's Financial Metrics

Credit strengths

» Credit supportive regulatory environment in Michigan

» Transparent and timely cost recovery

» Stable financial profile

Credit challenges

» Robust capital investment plan

» Maintaining regulatory support for these capital investments

» Lack of geographic and regulatory diversity with single state service territory

Rating outlook

The stable outlook reflects our expectation that financial metrics will remain stable and that Consumers Energy will continue to benefit from a consistent and generally credit supportive regulatory environment. The stable outlook also incorporates our view that Consumers Energy will maintain prudent financial policies while managing through its robust investment cycle and that debt levels at the parent will not increase materially.

Factors that could lead to an upgrade

A rating upgrade could be considered if credit metrics improve such that CFO pre-WC to debt is above 21% on a sustained basis. In addition, if the Michigan regulatory framework becomes even more formulaic, transparent or timely with its suite of cost recovery mechanisms for Consumers Energy, a rating upgrade could be possible.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on https://ratings.moodys.com for the most updated credit rating action information and rating history.

Factors that could lead to a downgrade

A rating downgrade could be considered if there is a material deterioration in the credit supportiveness of the Michigan regulatory environment; or if the CFO pre-WC to debt ratio declines below 18% on a sustained basis.

Key indicators

Exhibit 2

Consumers Energy Company

	2019	2020	2021	2022	2023	LTM
CFO Pre-W/C + Interest / Interest	6.2x	6.6x	7.5x	7.1x	5.8x	5.6x
CFO Pre-W/C / Debt	20.1%	21.5%	22.6%	20.0%	19.1%	18.7%
CFO Pre-W/C – Dividends / Debt	12.7%	14.1%	14.6%	12.7%	13.0%	13.0%
Debt / Capitalization	46.0%	44.9%	43.7%	45.1%	45.8%	46.7%

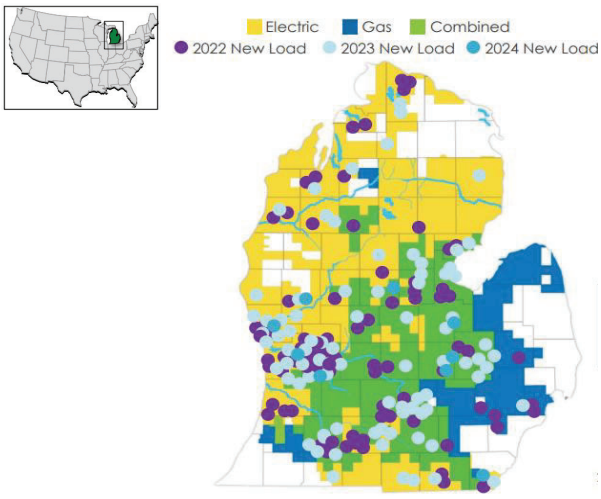
All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Credit metrics included in the exhibit include securitization bonds. When we adjust the total debt to exclude securitization debt, Consumers Energy's CFO pre-WC/debt would be 20.3%, 20.5% and 20.0% in 2022, 2023 and LTM ending 31 March 2024, respectively.
Source: Moody's Financial Metrics

Profile

Consumers Energy is a vertically integrated electric and gas utility serving approximately 1.9 million electric and 1.8 million gas customers in the state of Michigan with an average rate base of $25 billion in 2023. Consumers Energy's electric operations account for approximately two thirds of its revenue, cash flow and asset base. The utility is a wholly-owned subsidiary of CMS and, as the primary subsidiary of the parent company, it represents over 95% of CMS's consolidated earnings. In addition to Consumers Energy, CMS has a subsidiary called NorthStar Clean Energy, a non-utility domestic independent power producer and marketer.

Exhibit 3

Consumers Energy's Service Territory



Source: Company Presentations

Detailed credit considerations

Credit supportive regulatory environment

Consumers Energy is regulated by the MPSC, which has a regulatory framework that we view to be more credit supportive than most other states. As a result of 2008 and 2016 energy legislation in Michigan, the regulatory framework has been streamlined, improving both the rate case process and the timeliness of cost recovery. The 2016 legislation provided additional assurance of utility investment recovery by expanding the certificate of necessity (CON) process, which had already included pre-construction approval for large

generating resources, into an integrated resource planning (IRP) process. The IRP process considers a wide range of factors including fuel costs, demand forecasts, resource adequacy, competitive pricing, environmental mandates and transmission options before the construction of major projects.

In November 2023, new energy legislation (2023 Energy Law) was enacted. Under the new law, the state's renewable energy standards were raised to 50% by 2030 and 60% by 2035 from the previous 15% by 2021 requirement. It also set a clean energy standard of 80% by 2035 and 100% by 2040. Under the law, zero to low-carbon emitting sources, such as nuclear generation and natural gas generation with carbon capture, are considered clean energy sources. Along with these new standards, the new legislation expanded the authority of the MPSC to oversee their implementation. CMS's utility subsidiary Consumers Energy will file updates to its renewable energy plans in 2024 and its Clean Energy Plan in or before 2027. Given the existing regulatory framework in Michigan, we expect the company's collaborative dialogue with both stakeholders and regulator to continue under the new legislation.

In June 2022, Consumers Energy and key stakeholders in Michigan reached a settlement related to the company's latest IRP. The settlement included the retirement of all of its remaining coal power plants (all three units at the Campbell power plant site) in 2025 as a result of the 2021 IRP. Consumers Energy will be able to record approximately $1.3 billion of the remaining book value of these power plants as a regulatory asset and earn a 9% return on equity (ROE) through the remaining life. Instead of securitizing the remaining book value, the settlement will minimize the impact of the accelerated coal retirements on Consumers Energy's credit metrics. We view this settlement to be constructive and evidence of continued credit supportiveness in Michigan.

Timeliness of cost recovery based on a prescriptive suite of recovery mechanisms

Michigan utilities benefit from numerous formulaic rate adjustment mechanisms that provide a high degree of cash flow stability and assurance of recovery. For example, Consumers Energy has forward-looking Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) mechanisms that are intended to ensure that it can recover prudently incurred power and gas supply costs. The PSCR covers fuel and purchased power costs as well as transmission and emission allowance costs. Differences between actual and forecast costs are deferred for recovery or refunded in the following year. The PSCR is a surcharge mechanism and provides a degree of base rate and cash flow stability, a credit positive. The GCR mechanism may be adjusted monthly within a capped range to minimize over/under recoveries, although interim gas inventory buildup could substantially increase the company's working capital financing when gas prices increase sharply.

Gas utilities in the state also benefit from programs designed to assure recovery of needed infrastructure improvements. Consumers Energy's RDM compares and adjusts for differences between weather normalized actual and authorized revenues. The company's enhanced infrastructure replacement program (EIRP) is a MPSC authorized 25-year incremental investment program to upgrade natural gas infrastructure, including replacing less than 250 miles of cast iron pipe and other high-risk components.

Active rate case filing cadence

Consumers Energy maintains an active regulatory schedule with its electric and gas general rate cases typically filed annually in an alternating pattern. The utility currently has its gas rate case pending before the MPSC, and filed its request for an electric rate increase on 31 May 2024. Over the last three years, Consumers Energy experienced downward pressure on its allowed ROE in its rate cases although the company was able to maintain a 9.9% allowed ROE. We expect Consumers Energy to maintain a stable financial profile because there are other offsetting mechanisms such as usage of forward test year to allow the utility to earn appropriate returns and to recover investment costs on a timely basis. However, further deterioration of the allowed ROE is likely to put negative pressure on the company's overall financial profile.

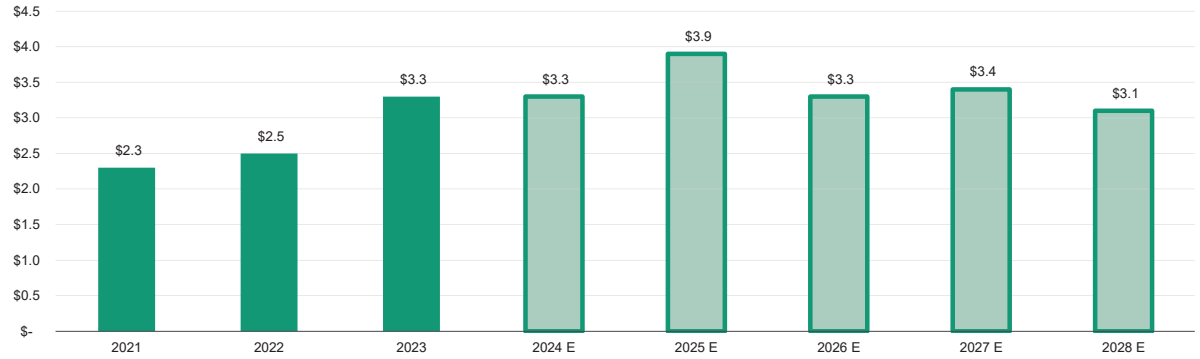
On 1 March 2024, the commission authorized a $92 million increase based on a 9.9% ROE, 50.02%% equity capital structure and a $13.67 billion rate base value. Also, the final order approved an Investment Recovery Mechanism (IRM) rider for distribution reliability projects totaling $99 million over two years.

On 15 December 2023, the utility filed a gas rate case, seeking a $136 million increase based on a projected test year for the 12-month period ending 30 September 2025, requesting a 10.25% ROE, 51.5% equity capital structure and a rate base value estimated around $10.97 billion. In April 2024, the MPSC Staff recommended an $70.77 million increase based on a 9.85% ROE, 49.92% equity capital structure and a $10.88 billion rate base value. A final decision is expected by 15 October 2024.

Stable credit metrics expected to be maintained through its high capital investment cycle

Consumers Energy's capital spending continues to be robust as it is currently in the midst of a large capital investment plan. The company increased its five-year capital expenditure plan through 2028 to $17 billion, approximately $1.5 billion higher than the previous plan. Consumers Energy will invest approximately $6.3 billion primarily to maintain and upgrade its gas utility infrastructure; $7.3 billion related to its electric distribution and other infrastructure; and $3.4 billion related to clean energy generation. These investments should enhance the company's reliability and safety as well as help it execute its decarbonization plan.

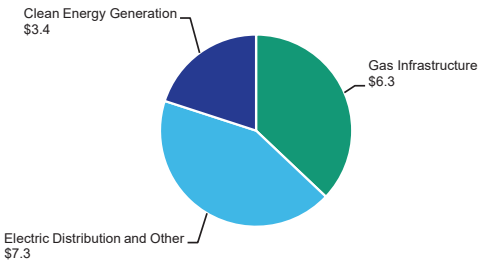
Exhibit 4
Consumers Energy's elevated capital program will extend at least through 2028
$ billions



Source: Company 10K

Through this period, Consumers Energy plans to keep rate increases modest, which should help to maintain regulatory support for investment cost recovery. Funding for these investments will be provided by internally generated cash flow, the issuance of debt at Consumers Energy and equity contributions from CMS. We expect Consumers Energy to maintain its CFO pre-WC to debt at around 20%-21% on average over the next 2-3 years. At the end of 2023 and for the LTM period ending 31 March 2024, Consumers Energy produced a CFO pre-WC to debt ratio of 20.5% and 20%, respectively, excluding securitization debt.

Exhibit 5
Planned Capital Expenditures 2024 - 2028
$ billions



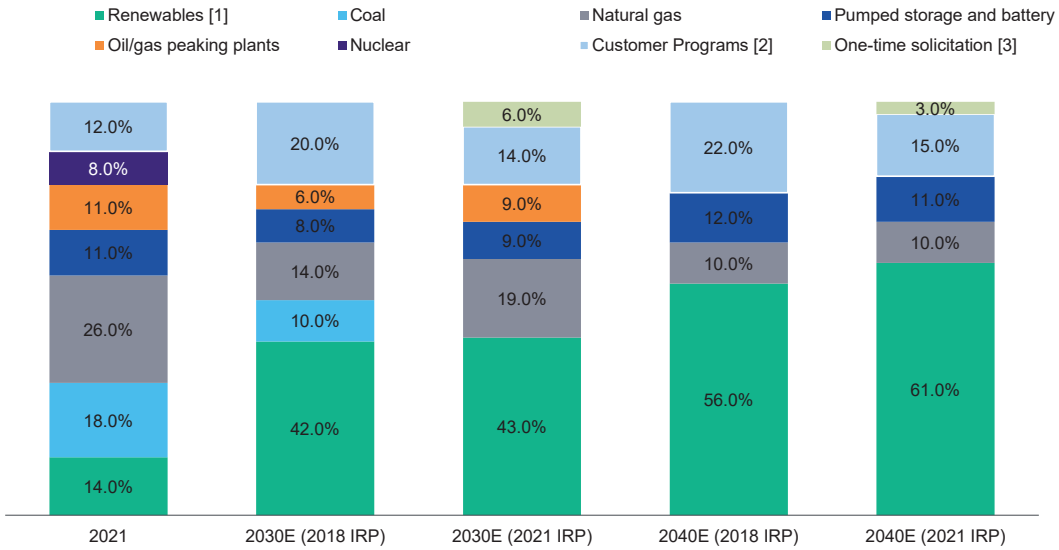
Source: Company 10K

Based on Consumers' latest IRP approved in 2022, the utility will add up to 8 GW of solar power, which is 2 GW more than what was approved in the company's 2018 IRP. As a result, by 2040, more than 60% of Consumers Energy's generation capacity will be from renewable sources. In order to replace the retiring coal capacity, the utility acquired the Covert natural gas-fired power plant for

approximately $815 million in 2023. It issued requests for proposals (RFP) for two purchased power agreements (PPA) for 500 MW of dispatchable generation and 200 MW of clean energy sources.

Exhibit 6

Based on the latest IRP settlement, more than 60% of Consumers Energy's generation sources will be renewables by 2040



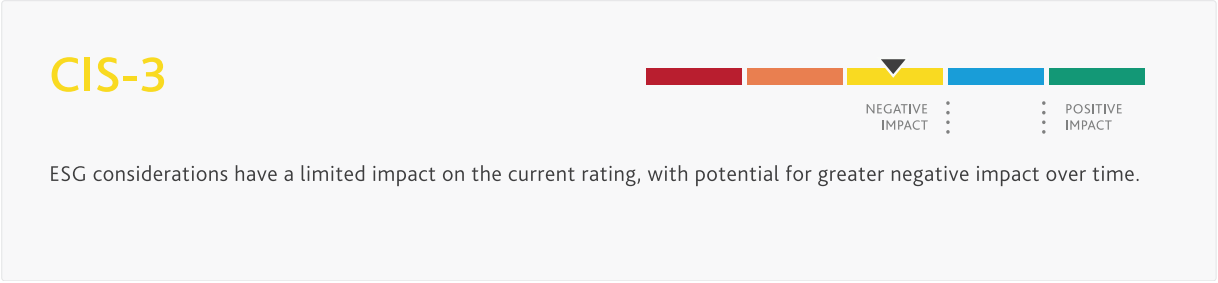
[1] Does not include renewable RECs.
[2] Includes energy waste reduction, demand response, and conservation voltage reduction program.
[3] One-time solicitation to acquire approximately 700 MW of capacity from sources in Michigan's Lower Peninsula beginning in 2025.
Source: Company's 10-K in 2022 and 2021, and latest investor presentation

ESG considerations

Consumers Energy Company's ESG credit impact score is CIS-3

Exhibit 7

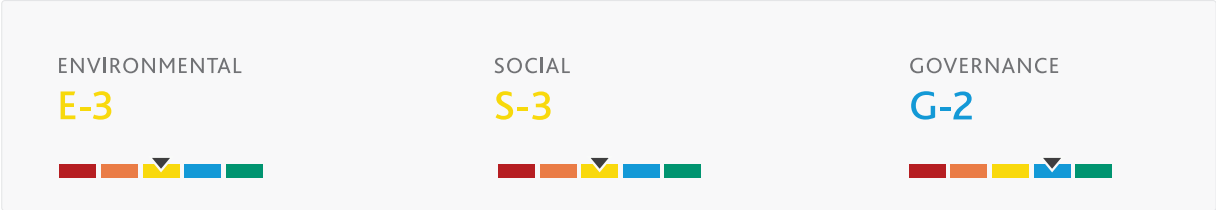
ESG credit impact score



Source: Moody's Ratings

Consumers Energy's **CIS-3** indicates that ESG considerations have limited impact on the current credit rating with greater potential for negative impact over time. It reflects some exposure to physical climate risk and moderating carbon transition risk. It also incorporates social risks stemming from inherent risk associated with regulated utilities and governance risk that is not a material driver.

Exhibit 8
ESG issuer profile scores



Source: Moody's Ratings

Environmental

Consumers Energy's **E-3** issuer profile score reflects its moderate position for the carbon transition with tangible strategies and plans in place that substantially mitigate its carbon transition exposure. The utility is currently in a transition to phase out its coal-fired generation and targets zero coal-fired generation output in 2025, accelerated from its prior target of 2039. The utility also established a goal of net zero methane emission for its gas delivery system by 2030; net zero carbon emissions for its electric business by 2040, including MISO market purchases and PPAs; and net zero greenhouse gas emissions for its entire business, including customer and supplier emissions, by 2050. Michigan's regulatory framework supports the utility's transition plan by allowing certain investment cost recovery and renewable energy plan surcharges, for example.

Social

S-3 issuer profile score for Consumers Energy is primarily related to its customer and regulatory relations as well as demographic and societal trends. The utility's regulatory environment, as well as its interaction with the Michigan Public Service Commission, are important in considering the utility's social risk. Also, the safety and reliability of its operations are important social considerations.

Governance

Consumers Energy's **G-2** issuer profile score reflects our view that its governance does not pose a particular risk and is not a material driver in the company's overall credit profile. It also incorporates its position as a subsidiary of CMS whose corporate governance considerations including financial policy and risk management influence Consumers Energy.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

We expect Consumers Energy's liquidity profile to be adequate over the next 12-18 months.

Consumers Energy's external liquidity sources include a $1.1 billion secured revolving credit facility expiring in December 2027 and, as of 31 March 2024, net availability was $1.073 billion with $27 million of letters of credit outstanding. Consumers Energy also maintains a $250 million secured credit facility terminating in November 2025 and had $197 million available as of 31 March 2024. Both facilities are secured by first mortgage bonds. These credit facilities provide support for working capital needs and act as a backstop to Consumer Energy's $500 million commercial paper program. At 31 March 2024, the company had no commercial paper notes outstanding under the program. The credit facilities do not include a material adverse change representation for new borrowings, and have only one financial covenant, setting the maximum debt to capital at 65%. At 31 March 2024, debt to capital was 50%.

These facilities includes sustainability linked pricing metrics, which permits pricing adjustments for meeting targets related to sustainability. Targets include renewable generation and diverse supplier spend, highlighting its commitment to shifting its exposure to a greater renewable content and to supplier diversity.

The utility's continuing capital expenditure program and dividend policy will result in negative free cash flow for the foreseeable future. However, the company has a reasonable amount of external liquidity, demonstrated market access, and regularly receives capital contributions from its parent.

For the LTM period ended 31 March 2024, Consumers generated approximately $2.3 billion of cash from operations, invested $3.2 billion and distributed $673 million of dividends to CMS, resulting in negative free cash flow of approximately $1.6 billion. Given its robust investment plan, we expect Consumers Energy to maintain its negative free cash flow position over the 12-18 months.

In January 2024, Consumers Energy issued $600 million first mortgage bonds with 4.6% rate maturing in May 2029.

Rating methodology and scorecard factors

Exhibit 9

Methodology Scoring Factors
Consumers Energy Company

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2024		Moody's 12-18 Month Forward View As of 5/19/2024 [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.5x	Aa	5x - 6x	A
b) CFO pre-WC / Debt (3 Year Avg)	20.4%	Baa	20% - 21%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	13.4%	Baa	13% - 14%	Baa
d) Debt / Capitalization (3 Year Avg)	44.5%	A	45% - 46%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A2		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		A2		A3
b) Actual Rating Assigned				A3

* Senior Secured Rating.
[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 3/31/2024.
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Appendix

Exhibit 10

Cash Flow and Credit Metrics

CF Metrics (in $ millions)	2019	2020	2021	2022	2023	LTM
FFO	**1,752**	**1,994**	**2,054**	**2,125**	**2,065**	**2,136**
+/- Ot er	129	136	13	29	125	98
CFO Pre-WC	**1,623**	**1,858**	**2,041**	**2,096**	**2,190**	**2,234**
+/- ΔWC	15	25	53	1 098	243	108
CFO	**1,608**	**1,883**	**1,988**	**998**	**2,433**	**2,342**
- Di	593	638	723	770	696	674
- Capex	2 100	2 184	2 066	2 256	2 260	2 289
FCF	1 085	939	801	2 028	523	621
CFO Pre-W/C / Debt	20.1%	21.5%	22.6%	20.0%	19.1%	18.7%
CFO Pre-W/C - Di i en s / Debt	12.7%	14.1%	14.6%	12.7%	13.0%	13.0%
FFO / Debt	21.6%	23.0%	22.8%	20.3%	18.0%	17.9%
CF / Debt	14.3%	15.7%	14.8%	12.9%	12.0%	12.2%
e en e	6 376	6 189	7 021	8 151	7 166	7 053
Interest xpense	312	332	315	342	455	482
et In o e	725	798	838	883	802	842
Total ssets	23 699	25 399	27 140	29 916	31 852	32 209
Total Liabilities	16 053	16 862	17 880	19 780	21 071	21 418
Total it	7 647	8 538	9 261	10 137	10 782	10 792

All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 11

Peer Comparison Table

	Consumers Energy Company (P)A3 Stable			DTE Electric Company (P)A2 Stable			DTE Gas Company A3 Stable			Northern States Power Company (Minnesota) A2 Stable			Wisconsin Power and Light Company Baa1 Stable		
(In $ millions)	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-22	FY Dec-23	LTM Mar-24
Revenue	8,151	7,166	7,053	6,397	5,804	5,895	1,894	1,726	1,736	6,684	6,043	5,913	1,856	1,827	1,817
CFO Pre-W/C	2,096	2,190	2,234	2,164	2,565	2,726	575	638	580	2,034	2,259	2,306	317	602	595
Total Debt	10,472	11,454	11,957	11,408	12,523	12,612	2,602	2,642	2,565	7,292	7,692	8,212	3,323	3,700	3,679
CFO Pre-W/C + Interest / Interest	7.1x	5.8x	5.6x	6.5x	6.7x	6.8x	7.2x	7.2x	6.4x	8.2x	7.8x	7.7x	4.5x	7.4x	6.6x
CFO Pre-W/C / Debt	20.0%	19.1%	18.7%	19.0%	20.5%	21.6%	22.1%	24.1%	22.6%	27.9%	29.4%	28.1%	9.5%	16.3%	16.2%
CFO Pre-W/C – Dividends / Debt	12.7%	13.0%	13.0%	12.3%	12.5%	13.6%	15.8%	16.9%	14.9%	20.2%	21.0%	20.2%	4.2%	11.3%	11.1%
Debt / Capitalization	45.1%	45.8%	46.7%	47.4%	48.4%	48.6%	44.5%	42.3%	39.4%	43.4%	43.0%	43.2%	43.8%	44.0%	43.5%

All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End; LTM = Last Twelve Months.
Source: Moody's Financial Metrics

Ratings

Exhibit 12

Category	Moody's Rating
CONSUMERS ENERGY COMPANY	
Outlook	Stable
Sr Sec Bank Credit Facility	A1
First Mortgage Bonds	A1
Senior Secured Shelf	(P)A1
LT IRB/PC	A3
Pref. Stock	Baa1
Commercial Paper	P-2
PARENT: CMS ENERGY CORPORATION	
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Pref. Stock	Ba1

Source: Moody's Ratings

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REPORT NUMBER 1409540

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Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MPSC Case No.	**U-21806**
Responding Party:	Attorney General
Respondent:	Sebastian Coppola
Requestor:	CECo
Question No.:	**3-CE-AG-5**

3-CE-AG-5

On page 125 of his direct testimony, Mr. Coppola addresses Company witness Bleckman's Exhibit A-32 (MRB-10) - Peer Company Commission Authorized Equity Ratios. Mr. Coppola claims that "commissions in those jurisdictions also included a permanent layer of short-term debt as part of the permanent capital structure." With regard to this statement, please:

i. Identify all companies included in Mr. Bleckman's Exhibit A-32 (MRB-10) that employ short-term debt as a permanent financing tool along with supporting evidence.

ii. What criteria did Mr. Coppola apply to determine whether or not a given company's short-term debt is "permanent"?

Response:
i and ii.

In the past two years, the companies and related utility subsidiaries that have used short-term debt to meet permanent financing (long-term) needs are NiSource, One Gas, Spire Missouri, and WEC Energy. My criterion in evaluating each individual situation was that if a company had substantial short-term debt for five consecutive quarter ends, then the company was using short-term debt to supplement long-term debt. This is similar to how the accounting profession views long-term liabilities. All of these companies meet this criterion. The quarterly balances below for each of the companies were sourced from SEC filings. It should be recognized that WEC Energy, and NiSource act as the financing arm for their utility subsidiaries and therefore it is these companies' financial statements that are relevant and not the subsidiaries where debt coming in from the parent companies can also be categorized as common equity capital at the utility subsidiary. Similarly, One Gas operates on a divisional basis and therefore its financial statements are the relevant source of debt/equity capitalization for the utility divisions. Spire Missouri's financial statements are filed with its parent company on Form 10-K and 10-Q reports.

Quarter End Short-Term Debt (Millions of Dollars)

	WEC Energy 2023-2024	NiSource 2023-2024	One Gas 2023-2024	Spire Mo. 2023-2024
December	$ 2,021	$ 3,049	$ 89	$ 633
March	2,574	1,222	953	444
June	761	644	1,032	418
September	597	257	951	495
December	1,017	605	915	581

Date: 5/2/2025

MPSC Case No.	**U-21806**
Responding Party:	Attorney General
Respondent:	Sebastian Coppola
Requestor:	CECo
Question No.:	**3-CE-AG-6**

3-CE-AG-6

Refer to page 126 of Mr. Coppola's direct testimony which states that "Smaller utilities tend to have higher equity ratios to sustain them during potential volatility in their business, which larger utilities can better manage." Please provide all analyses, studies, or reports Mr. Coppola relied on in making this statement.

Response:

In establishing that smaller utilities tend to have higher equity ratios, Mr. Coppola relied on his knowledge and experience accumulated over the past nearly 50 years that he has been involved in the utility industry. Appendix A to Mr. Coppola's direct testimony shows his vast background as Chief Financial Officer, Treasurer, and financial manager involved in various aspects of financing and managing large and small utilities.

Mr. Coppola has also relied on research and a publication issued by financial expert, Dr. Roger A. Morin. The attached excerpt from Dr. Morin's book New Regulatory Finance provides supporting evidence on the higher business and financial risks faced by smaller utilities. See 3-CE-AG-6 Attach 1.

Date: 5/2/2025

MPSC Case No.	**U-21806**
Responding Party:	Attorney General
Respondent:	Sebastian Coppola
Requestor:	CECo
Question No.:	**3-CE-AG-7**

3-CE-AG-7

On page 127 of his direct testimony, Mr. Coppola addresses Company witness Bleckman's Exhibit A-32 (MRB-10) – Peer Company Commission Authorized Equity Ratios. Mr. Coppola claims that the Company's analysis is inflated due to the fact that "utilities on the east coast of the United States were not represented in Mr. Bleckman's exhibit, where equity ratios and ROEs tend to be lower and more conservative." Please provide all analyses, studies, or reports Mr. Coppola relied on in making this statement.

Response:

The following information sourced from S&P Global (Regulatory Research Associates Division) shows ROE decisions from regulatory commissions pertaining to several east coast utilities. This information is also included in Exhibit AG-48. The Common Equity ratios reported by Regulatory Research Associates from related rate cases are also shown below.

	Utility	State	ROE Date	ROE	Equity Ratio
a.	Consolidated Edison of NY	NY	Jul 20, 2023	9.25%	48%
b.	Northern Utilities	ME	Sep 20, 2023	9.35%	52%
c.	New York State Elec. & Gas	NY	Oct 12, 2023	9.20%	48%
d.	Rochester Gas & Electric	NY	Oct 12, 2023	9.20%	48%
e.	Central Hudson Gas & Elec.	NY	Jul 18, 2024	9.50%	48%
f.	KeySpan Gas East	NY	Aug 15, 2024	9.35%	48%
g.	Brooklyn Union Gas	NY	Aug 15, 2024	9.35%	48%
h.	Connecticut Nat. Gas	CT	Nov 9, 2024	9.15%	53%
i.	Southern Connecticut Gas	CT	Nov 9, 2024	9.15%	53%
j.	New Jersey Natural Gas	NJ	Nov 16, 2024	9.60%	54%
k.	National Fuel Gas	NY	Dec 4, 2024	9.70%	48%

Date: 5/2/2025

MPSC Case No.	**U-21806**
Responding Party:	Attorney General
Respondent:	Sebastian Coppola
Requestor:	CECo
Question No.:	**3-CE-AG-8**

3-CE-AG-8

Refer to page 103, lines 1 through 4, and page 104, lines 5 through 11, of Mr. Coppola's direct testimony which refers to an analysis that the Company performed to use as a basis for its 1% of revenues measure for projecting the test year cash balance. Please state the specific testimony and/or exhibit along with the relevant case number that contains the Company's analysis Mr. Coppola is referring to.

Response:

Refer to the direct and rebuttal testimony of Company witness Andrew Donato and Exhibit A-93 filed in Case No. U-17990. This information should already be available to the Company.

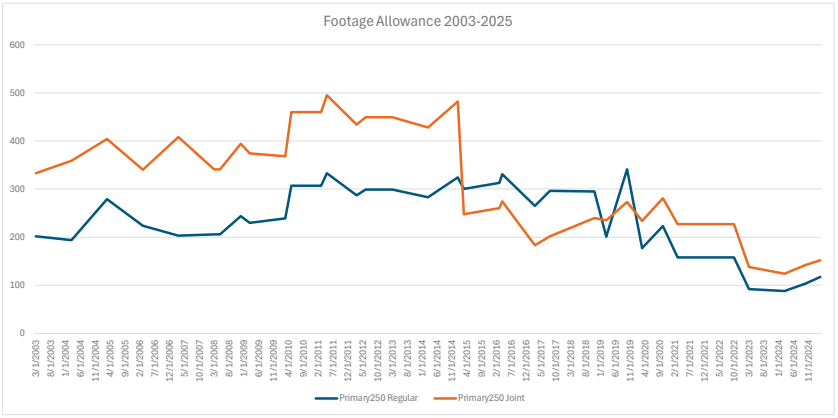
Date: 5/2/2025

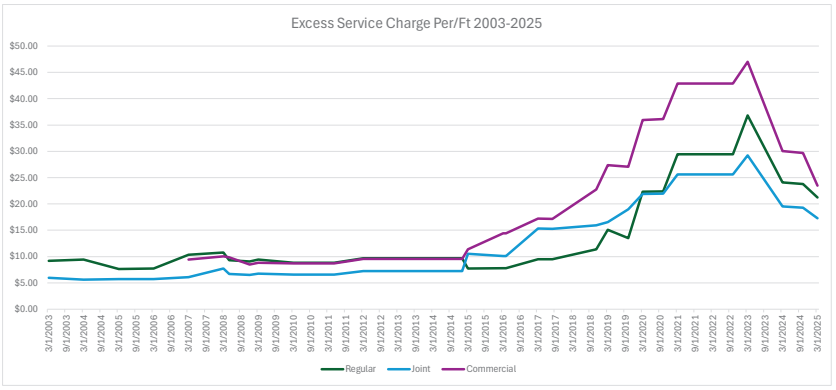
MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Footage Allowance Excess Service Charge Trends 2003-2025

Case No.: U-21806
Exhibit No.: A-119 (LAB-1)
Page: 1 of 2
Witness: LABonner
Date: May 2025

		Service Footage Allowance by Class of Metering									Excess Service Charge per/ft	Additional Directional Bore per/ft
		Primary3M	Primary2M	Primary1.5M	Primary800	Primary 630	Primary425	Primary250	Seasonal	Mobile Home		
March 1st 2025	Regular				117		117	117	117	117	$21.26	$14.91
	Joint				152		152	152	152	152	$17.28	$14.91
	Commercial										$23.46	$14.91
October 1st 2024	Regular				103		103	103	103	103	$23.81	$13.30
	Joint				142		142	142	142	142	$19.31	$13.30
	Commercial										$29.68	$13.30
March 1st 2024	Regular				88		88	88	88	88	$24.10	$13.30
	Joint				124		124	124	124	124	$19.55	$13.30
	Commercial										$30.03	$13.30
March 1st 2023	Regular				92		92	92	92	92	$36.82	$8.80
	Joint				138		138	138	138	138	$29.23	$8.80
	Commercial										$47.01	$8.80
October 1st 2022	Regular				1071		544	158	0	52	$29.47	$8.80
	Joint				1278		672	227	24	105	$25.60	$8.80
	Commercial										$42.90	$8.80
March 1st 2021	Regular				1071		544	158	0	52	$29.47	$8.80
	Joint				1278		672	227	24	105	$25.60	$8.80
	Commercial										$42.90	$8.80
October 1st 2020	Regular				1424		731	223	0	84	$22.41	$8.80
	Joint				1505		799	281	46	140	$21.99	$8.80
	Commercial										$36.12	$8.80
March 1st 2020	Regular				1210		615	177	0	57	$22.31	$8.80
	Joint				1287		681	234	30	111	$21.89	$8.80
	Commercial										$35.96	$8.80
October 1st 2019	Regular				2045		1064	341	11	143	$13.53	$8.80
	Joint				1486		787	273	37	131	$19.00	$8.80
	Commercial										$27.07	$8.80
March 1st 2019	Regular				1337		685	201	0	67	$15.08	$8.80
	Joint				1272		677	235	32	113	$16.52	$8.80
	Commercial										$27.36	$8.80
November 2nd 2018	Regular				1801		937	295	0	117	$11.37	$8.80
	Joint				1313		697	240	29	113	$15.96	$8.80
	Commercial										$22.77	$8.80
August 7th 2017	Regular				1949	1595	1002	296	0	99	$9.47	$8.80
	Joint				1226	1006	639	202	0	80	$15.30	$8.80
	Commercial										$17.18	$8.80
March 1st 2017	Regular				1800	1475	922	265	0	82	$9.49	$8.80
	Joint				1134	932	590	183	0	69	$15.32	$8.80
	Commercial										$17.22	$8.80
April 22nd 2016	Regular				2194	1800	1129	331	0	108	$7.82	$8.80
	Joint				1717	1411	892	274	0	101	$10.09	$8.80
	Commercial										$14.43	$8.80
March 1st 2016	Regular				2110	1733	1084	313	0	98	$7.82	$8.80
	Joint				1652	1359	857	260	0	94	$10.09	$8.80
	Commercial										$14.43	$8.80
March 1st 2015	Regular				2111	1730	1076	300	0	83	$7.76	$8.80
	Joint				1579	1299	819	248	0	89	$10.55	$8.80
	Commercial										$11.37	$8.80
January 21st 2015	Regular	6790	4426	3010	1773	1468	945	324	35	150	$9.70	$8.80
	Joint	9143	5976	4080	2423	2015	1314	482	95	250	$7.24	$8.80
	Commercial										$9.58	$8.80
March 1st 2014	Regular	6280	4085	2771	1625	1345	859	283	15	122	$9.68	$8.80
	Joint	8460	5520	3760	2224	1850	1199	428	68	212	$7.23	$8.80
	Commercial										$9.56	$8.80
March 1st 2013	Regular	6542	4260	2893	1698	1404	899	299	20	132	$9.68	$8.80
	Joint	8811	5754	3924	2323	1929	1253	449	75	225	$7.23	$8.80
	Commercial										$9.56	$8.80
June 8th 2012	Regular	6542	4260	2893	1698	1404	899	299	20	132	$9.68	$8.80
	Joint	8811	5754	3924	2323	1929	1253	449	75	225	$7.23	$8.80
	Commercial										$9.56	$8.80
March 1st 2012	Regular	6327	4117	2794	1639	1356	867	287	17	125	$9.68	$8.80
	Joint	8531	5568	3794	2245	1867	1211	434	71	216	$7.23	$8.80
	Commercial										$9.57	$8.80
May 27th 2011	Regular	7104	4628	3145	1850	1531	984	333	30	152	$8.84	$8.80
	Joint	9572	6253	4265	2528	2102	1367	495	89	252	$6.59	$8.80
	Commercial										$8.73	$8.80
March 1st 2011	Regular	6539	4253	2887	1697	1410	905	307	28	139	$8.84	$8.80
	Joint	8815	5750	3918	2323	1939	1261	460	85	235	$6.59	$8.80
	Commercial										$8.73	$8.80
May 18th 2010	Regular	6539	4253	2887	1697	1410	905	307	28	139	$8.84	$8.80
	Joint	8815	5750	3918	2323	1939	1261	460	85	235	$6.59	$8.80
	Commercial										$8.73	$8.80
March 1st 2010	Regular	5519	3569	2408	1404	1174	743	239	0	95	$8.84	$8.80
	Joint	7448	4833	3276	1931	1622	1044	368	48	176	$6.59	$8.80
	Commercial										$8.73	$8.80
March 1st 2009	Regular	5410	3581	2464	1321	1105	702	230	6	96	$9.44	$8.80
	Joint	7277	4728	3210	1898	1597	1033	374	62	187	$6.76	$8.80
	Commercial										$8.82	$8.80
December 24th 2008	Regular	5624	3725	2565	1378	1153	734	244	12	105	$9.09	$8.80
	Joint	7553	4909	3335	1975	1662	1078	394	71	200	$6.52	$8.80
	Commercial										$8.49	$8.80
May 27th 2008	Regular	5055	3348	2298	1229	1026	648	206	0	81	$9.31	$8.80
	Joint	6797	4414	2995	1768	1485	958	341	50	166	$6.67	$8.80
	Commercial										$9.84	$8.80
March 1st 2008	Regular	5055	3348	2298	1229	1026	648	206	0	81	$10.75	$8.80
	Joint	6797	4414	2995	1768	1485	958	341	50	166	$7.71	$8.80
	Commercial										$10.04	$8.80
March 1st 2007	Regular	5140	3397	2333	1252	1040	656	203	0	76	$10.35	$8.80
	Joint	8408	5463	3706	2183	1825	1173	408	48	192	$6.12	$8.80
	Commercial										$9.43	$8.80
March 1st 2006	Regular				1262	1074	678	224	4	92	$7.74	$8.80
	Joint				1740	1487	952	340	43	162	$5.73	$8.80
	Commercial											$8.80
March 1st 2005	Regular				1408	1079	774	279	37	134	$7.64	$8.80
	Joint				1917	1476	1068	404	81	210	$5.70	$8.80
	Commercial											$8.80
March 1st 2004	Regular				955		532	194	26	93	$9.42	$8.80
	Joint				1636		926	359	78	190	$5.62	$8.80
	Commercial											$8.80
March 1st 2003	Regular				980		547	202	30	98	$9.22	$8.80
	Joint				1528		862	333	70	175	$6.00	$8.80
	Commercial											$8.80

Date	Primary250 Regular	Primary250 Joint	Excess Service Charge Regular	Excess Service Charge Joint	Excess Service Charge Commercial
3/1/2025	117	152	$21.26	$17.28	$23.46
10/1/2024	103	142	$23.81	$19.31	$29.68
3/1/2024	88	124	$24.10	$19.55	$30.03
3/1/2023	92	138	$36.82	$29.23	$47.01
10/1/2022	158	227	$29.47	$25.60	$42.90
3/1/2021	158	227	$29.47	$25.60	$42.90
10/1/2020	223	281	$22.41	$21.99	$36.12
3/1/2020	177	234	$22.31	$21.89	$35.96
10/1/2019	341	273	$13.53	$19.00	$27.07
3/1/2019	201	235	$15.08	$16.52	$27.36
11/2/2018	295	240	$11.37	$15.96	$22.77
8/7/2017	296	202	$9.47	$15.30	$17.18
3/1/2017	265	183	$9.49	$15.32	$17.22
4/22/2016	331	274	$7.82	$10.09	$14.43
3/1/2016	313	260	$7.82	$10.09	$14.43
3/1/2015	300	248	$7.76	$10.55	$11.37
1/21/2015	324	482	$9.70	$7.24	$9.58
3/1/2014	283	428	$9.68	$7.23	$9.56
3/1/2013	299	449	$9.68	$7.23	$9.56
6/8/2012	299	449	$9.68	$7.23	$9.56
3/1/2012	287	434	$9.68	$7.23	$9.57
5/27/2011	333	495	$8.84	$6.59	$8.73
3/1/2011	307	460	$8.84	$6.59	$8.73
5/18/2010	307	460	$8.84	$6.59	$8.73
3/1/2010	239	368	$8.84	$6.59	$8.73
3/1/2009	230	374	$9.44	$6.76	$8.82
12/24/2008	244	394	$9.09	$6.52	$8.49
5/27/2008	206	341	$9.31	$6.67	$9.84
3/1/2008	206	341	$10.75	$7.71	$10.04
3/1/2007	203	408	$10.35	$6.12	$9.43
3/1/2006	224	340	$7.74	$5.73	
3/1/2005	279	404	$7.64	$5.70	
3/1/2004	194	359	$9.42	$5.62	
3/1/2003	202	333	$9.22	$6.00	





MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Excess Service Cost Formula

Case No.: U-21806
Exhibit No.: A-120 (LAB-2)
Page: 1 of 3
Witness: LABonner
Date: May 2025

Line No.		(a)	(b)	(c)
1	Project Cost (- $200 connection fee)	26.91	2153.23	$21.26
2	Footage	118	218	

GEM Billables

TEST NEW RATES 2025

Go Back to GEM Project | Billable Summary | Calculate Cost

GEM Costing Setting (Admin Only)

2025 Revenue and Cost

Status

Billed

For service alterations, refer to the GDEM for billing cost.

Total Customer Cost
$226.91

Customer Main Costs:	$0
Customer Service Costs:	$26.91
Connection Fees:	$200.00

Created By	Created On	Approved By	Approved On
tthaney	5/1/2025 12:00:00 AM		

Direct Costs

Billable Type	Description	Cost
Cost	Connection Fees	200.00

Add Direct Cost

EPM Cost

0.00

Revenue Years

20

Main Costs

Add Main Billable

Add Service Similar Billable | View Example Graphics

Service Billables

Service Similar:12079

Delete Service Similar

Normal (Non-Joint)	Joint	Boring	Pre-Prop Line	Pipe Type	Pipe Size	Rate Name	Year Added
118.00	0.00	0.00	0.00	Plastic Yellow	5/8"	Residential	1 Saturation

Similar Count	Normal Cost	Boring Cost	Joint Cost	Excess FT Cost	HP Reg Billed	HP Reg Cost	Additional Cost	Conn. Fee	Total Cost
1	2691.58	0.00	0.00	0.00		0.00	0.00	200.00	4359.50

Meters Billables

Service Similar:12079

Meter Name	Pressure	Similar Count
250 TC	7"WC	1

Customer	Billing Class	Revenue MCF	Rate Name	Meter Cost	Meter Stand	Stand Cost	M&R Cost	Total Cost
Residential	Primary 250	94.00	Residential	225.90		0.00	0.00	225.90

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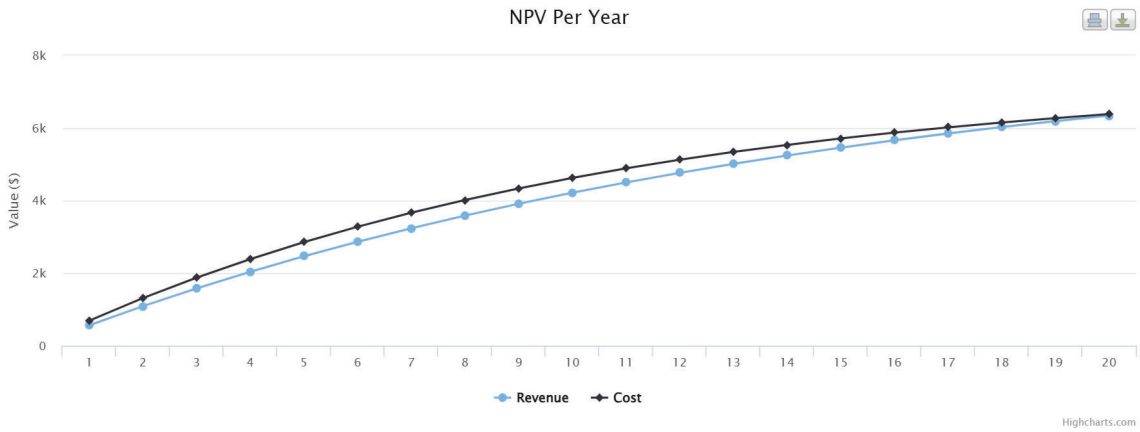
Gem Billables Summary

⚠ For Internal Use Only ⚠

Year 1 Main Cost	Year 1 Service Cost	Year 1 Meter Cost	Year 1 Direct Cost
0.00	4359.50	225.90	200.00
Total Main Cost	**Total Service Cost**	**Total Meter Cost**	**Total Direct Cost**
0.00	4359.50	225.90	200.00
Net Present Value Cost	**Net Present Value Revenue**	**Net Present Value Difference**	**Net Present Value Gross Up**
6381.76	6341.64	40.12	26.91
Total Customer Cost			**Non Recoverable Main Cost**
226.91			0.00



Close

GEM Billables

TEST NEW RATES 2025

Go Back to GEM Project | Billable Summary | Calculate Cost

GEM Costing Setting (Admin Only)

2025 Revenue and Cost

Status

Billed

For service alterations, refer to the GDEM for billing cost.

Total Customer Cost
$2353.23

Customer Main Costs:	**$0**
Customer Service Costs:	**$2153.23**
Connection Fees:	**$200.00**

Created By	Created On	Approved By	Approved On
tthaney	5/1/2025 12:00:00 AM		

Direct Costs

Billable Type	Description	Cost
Cost	Connection Fees	200.00

Add Direct Cost

EPM Cost

0.00

Revenue Years

20

Main Costs

Add Main Billable

Add Service Similar Billable | View Example Graphics

Service Billables

Service Similar:12079

Delete Service Similar

Normal (Non-Joint)	Joint	Boring	Pre-Prop Line	Pipe Type	Pipe Size	Rate Name	Year Added
218.00	0.00	0.00	0.00	Plastic Yellow	5/8"	Residential	1 Saturation

Similar Count	Normal Cost	Boring Cost	Joint Cost	Excess FT Cost	HP Reg Billed	HP Reg Cost	Additional Cost	Conn. Fee	Total Cost
1	4972.58	0.00	0.00	0.00		0.00	0.00	200.00	6640.50

Meters Billables

Service Similar:12079

Meter Name	Pressure	Similar Count
250 TC	7"WC	1

Customer	Billing Class	Revenue MCF	Rate Name	Meter Cost	Meter Stand	Stand Cost	M&R Cost	Total Cost
Residential	Primary 250	94.00	Residential	225.90		0.00	0.00	225.90

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Consumers Energy Company

Case No.: U-21806
Exhibit No.: A-121 (LAB-3)
Page: 1 of 1
Witness: LABonner
Date: May 2025

report_year	report_month	rate_category	is_apartment	gas_consumption	installation_count
2020	1	A_250	Yes	1080877	152216
2020	1	A_250	No	19426122.5	1325721
2020	2	A_250	Yes	1113111.6	152313
2020	2	A_250	No	19696775.8	1327393
2020	3	A_250	No	19977397	1329209
2020	3	A_250	Yes	1116146.4	152592
2020	4	A_250	No	13899875.3	1330361
2020	4	A_250	Yes	749824.9	151045
2020	5	A_250	Yes	574236.2	148920
2020	5	A_250	No	10845771.1	1330890
2020	6	A_250	Yes	248783.7	134226
2020	6	A_250	No	5037826.6	1322128
2020	7	A_250	Yes	128923.9	105480
2020	7	A_250	No	2544849.5	1284194
2020	8	A_250	No	2224229	1274060
2020	8	A_250	Yes	112773.4	100134
2020	9	A_250	Yes	125952.8	107866
2020	9	A_250	No	2553543.3	1289671
2020	10	A_250	No	4284604.5	1325287
2020	10	A_250	Yes	224044	133543
2020	11	A_250	No	9296285.7	1337935
2020	11	A_250	Yes	508493.1	149182
2020	12	A_250	No	15143084.9	1342016
2020	12	A_250	Yes	854707.1	152959
2021	1	A_250	Yes	1160900.5	153918
2021	1	A_250	No	20647416.7	1343212
2021	2	A_250	Yes	1306263	153190
2021	2	A_250	No	22588743.8	1330945
2021	3	A_250	No	20954704.2	1343933
2021	3	A_250	Yes	1200279.6	154739
2021	4	A_250	Yes	635474.9	153064
2021	4	A_250	No	11702601.6	1349778
2021	5	A_250	No	8731410.1	1348918
2021	5	A_250	Yes	466287.5	150194
2021	6	A_250	No	4564973	1342984
2021	6	A_250	Yes	227719.7	138718
2021	7	A_250	No	2575670.2	1307306
2021	7	A_250	Yes	129571.6	110962
2021	8	A_250	Yes	112260	101727
2021	8	A_250	No	2287453.2	1288434
2021	9	A_250	No	2276470.9	1288364
2021	9	A_250	Yes	112152.9	101339
2021	10	A_250	No	2772695.8	1320072
2021	10	A_250	Yes	145629.7	120188
2021	11	A_250	Yes	430435.8	146550
2021	11	A_250	No	7656923.5	1345944
2021	12	A_250	No	16058111.6	1352830
2021	12	A_250	Yes	900098.2	152411
2022	1	A_250	No	20391006.3	1353665
2022	1	A_250	Yes	1159341.8	153083
2022	2	A_250	No	25335849.7	1355068
2022	2	A_250	Yes	1452309.8	153453
2022	3	A_250	Yes	1250098.9	153274
2022	3	A_250	No	22328350.9	1357178
2022	4	A_250	Yes	880331.4	152654
2022	4	A_250	No	16071716.9	1359907
2022	5	A_250	Yes	555352.1	150086
2022	5	A_250	No	10619781.5	1360592
2022	6	A_250	Yes	193724.2	127923
2022	6	A_250	No	3997753.5	1344080
2022	7	A_250	Yes	120083.3	103290
2022	7	A_250	No	2462662.6	1305289
2022	8	A_250	Yes	114053.6	98893
2022	8	A_250	No	2403669.1	1296292
2022	9	A_250	No	2115424.4	1181335
2022	9	A_250	Yes	102804.1	93141
2022	10	A_250	Yes	206337.3	128682
2022	10	A_250	No	3903282.1	1338221
2022	11	A_250	Yes	458399.6	146987
2022	11	A_250	No	8467112.3	1358175
2022	12	A_250	Yes	901605.2	151796
2022	12	A_250	No	15970408.2	1363526
2023	1	A_250	No	20887538.7	1365416
2023	1	A_250	Yes	1179918.3	153071
2023	2	A_250	No	20359198.2	1366638
2023	2	A_250	Yes	1144801.9	153150
2023	3	A_250	Yes	1081293.7	153061
2023	3	A_250	No	19614766.7	1367786
2023	4	A_250	Yes	780002.5	151761
2023	4	A_250	No	14578543.6	1365154
2023	5	A_250	Yes	483455.1	149025
2023	5	A_250	No	9434394.8	1367236
2023	6	A_250	Yes	192893.2	125912
2023	6	A_250	No	3906792.8	1292796
2023	7	A_250	Yes	123229.6	106208
2023	7	A_250	No	2621319.9	1318248
2023	8	A_250	Yes	107738.5	99414
2023	8	A_250	No	2297530	1302736
2023	9	A_250	No	2475618.4	1311107
2023	9	A_250	Yes	116760	103938
2023	10	A_250	Yes	184262.3	1339868
2023	10	A_250	No	3492235.4	125907
2023	11	A_250	Yes	449254.1	146863
2023	11	A_250	No	8333796.2	1364012
2023	12	A_250	Yes	834293.2	151302
2023	12	A_250	No	15079471.7	1368077
2024	1	A_250	No	17800067.15	1382994
2024	1	A_250	Yes	981678.37	157070
2024	2	A_250	No	21533608.18	1384764
2024	2	A_250	Yes	1201469.3	157226
2024	3	A_250	Yes	856356	157143
2024	3	A_250	No	15785937.81	1386304
2024	4	A_250	Yes	771465.55	157303
2024	4	A_250	No	14160500.17	1387075
2024	5	A_250	Yes	368662.45	157087
2024	5	A_250	No	7207548.02	1386823
2024	6	A_250	Yes	160459.85	156940
2024	6	A_250	No	3316558.77	1386314
2024	7	A_250	Yes	117724.85	156794
2024	7	A_250	No	2487221.75	1385822
2024	8	A_250	Yes	104878.27	156647
2024	8	A_250	No	2211320.04	1385277
2024	9	A_250	No	2351851.14	1385011
2024	9	A_250	Yes	111508.98	156620
2024	10	A_250	Yes	135301.2	157091
2024	10	A_250	No	2653522.59	1385633
2024	11	A_250	Yes	316923.58	157299
2024	11	A_250	No	5960552.91	1385837
2024	12	A_250	Yes	774204.39	158061
2024	12	A_250	No	13600633.25	1388370

Average Installation Count

	2020	2021	2022	2023	2024	3 Year
No	1,318,239	1,330,227	1,331,111	1,242,926	1,385,852	1,319,963
Yes	136,706	136,417	134,439	236,131	157,107	175,892

Average Consumption by Year

	APT	Consumption	Premise Count	Ave Consumption
2020	NO	124,930,365.20	1,318,239	95
2020	YES	6,837,874.10	136,706	50
2021	NO	122,817,174.60	1,330,227	92
2021	YES	6,827,073.40	136,417	50
2022	NO	134,067,017.50	1,331,111	101
2022	YES	7,394,441.30	134,439	55
2023	NO	123,081,206.40	1,242,926	99
2023	YES	6,677,902.40	236,131	28
2024	NO	109,069,321.78	1,385,852	79
2024	YES	5,900,632.79	157,107	38
3 Year	NO	122,072,515.23	1,319,963	92
3 Year	YES	6,657,658.83	175,892	38

Average Consumption by Heating Season (Oct-May)

	APT	Consumption	Premise Count	Ave Consumption
2020/21	NO	113,348,851.50	1,324,233	86
2020/21	YES	6,356,449.70	136,562	47
2021/22	NO	121,234,436.20	1,330,669	91
2021/22	YES	6,773,597.70	135,428	50
2022/23	NO	113,215,244.60	1,287,018	88
2022/23	YES	6,235,813.60	185,285	34
2023/24	NO	103,393,164.63	1,314,389	79
2023/24	YES	5,647,441.27	196,619	29

Average Consumption Non-Heating Season (Jun-Sep)

	APT	Consumption	Premise Count	Ave Consumption
2021	NO	11,704,567.30	1,330,227	9
2021	YES	581,704.20	136,417	4
2022	NO	10,979,509.60	1,331,111	8
2022	YES	530,665.20	134,439	4
2023	NO	11,301,261.10	1,242,926	9
2023	YES	540,621.30	236,131	2
2024	NO	10,366,951.70	1,385,852	7
2024	YES	494,571.95	157,107	3

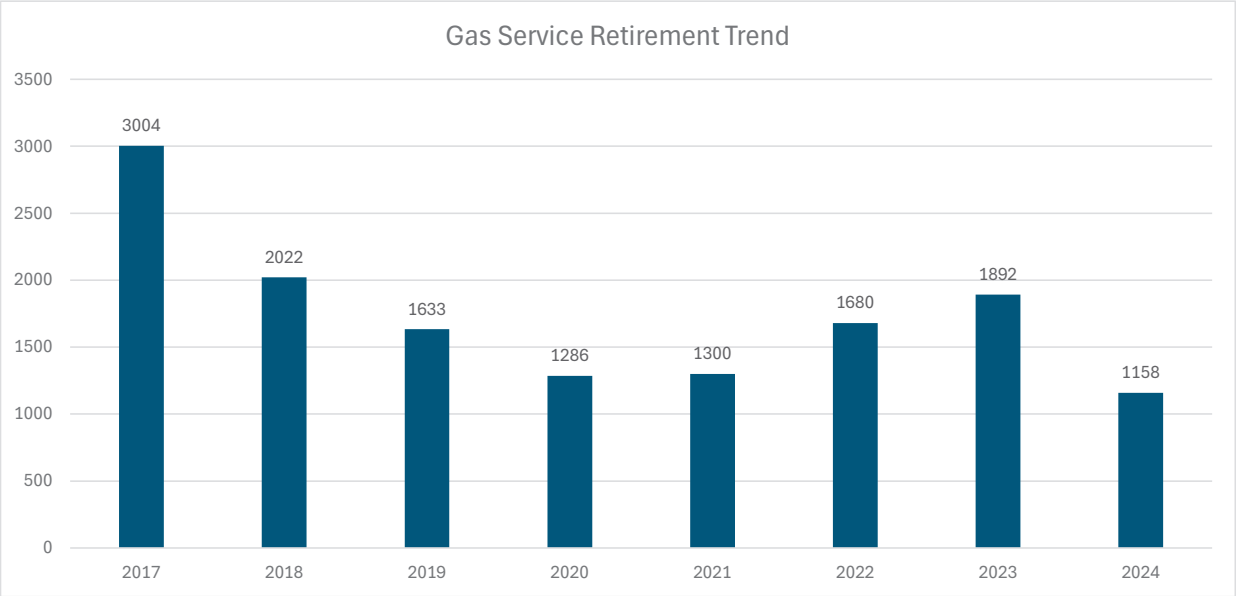
Average Consumption Previous Full Seasons (Jul-Jun)

	APT	Consumption	Premise Count	Ave Consumption
2020/21	NO	125,236,446.30	1,324,233	95
2020/21	YES	6,951,819.50	136,562	51
2021/22	NO	132,371,784.00	1,330,669	99
2021/22	YES	7,321,306.40	135,428	54
2022/23	NO	124,103,793.50	1,287,018	96
2022/23	YES	6,765,647.80	185,285	37
2023/24	NO	114,104,191.70	1,314,389	87
2023/24	YES	6,155,629.22	196,619	31
3 Year	NO	123,526,589.73	1,319,963	94
3 Year	YES	6,747,527.81	175,892	38

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21806
Exhibit No.: A-122 (LAB-4)
Page: 1 of 1
Witness: LABonner
Date: May 2025

Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
2	Gas Service Retirements	3004	2022	1633	1286	1300	1680	1892	1158



Customer Attachment Program
Line Extension Assumptions

Review with MNS & MPSC Staff
September 7, 2022

Consumers Energy
Count on Us®

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Agenda

- *Introductions*
- *Meeting Purpose*
- *Review 2021-2022 CAP changes*
- *Discuss Assumptions and Updates*
- *Q&A*

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Introductions

- *Dean Beach – Executive Director, Customer Energy Management*
- *Luther Bonner – CEM Process, Performance, & Technology Lead*
- *Chad Ammerman – CEM Process, Performance, & Technology*
- *Tyler Haney – CEM Data & Analytics*
- *Mike Rampe – Legal*
- *Doug Chapel – Regulatory Affairs*

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Meeting Purpose

- ***July 2022 Gas Rate Case Settlement:***

  "Consumers Energy agrees to meet with MNS and Staff to review and update the line extension assumptions within 90 days of the Commission issuing and order in this case. Consumers Energy additionally agrees to transition to a new line extension model that is transparent and capable of being shared with stakeholders for review to be completed by the end of 2022."

- ***Assumptions raised in Gas Rate Case:***
  - *Free footage*
  - *Gas throughput/consumption*

- ***Today, we will discuss data underlying these assumptions and our status on analyzing this data***

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2021 Rates – No Change for 2022

Residential	Service		2" Main		4" Main		6" Main
Gas Only	$ 29.47		$ 17.13		$ 54.01		$ 61.58
Joint	$ 25.60		$ 22.49		$ 68.13		$ 44.66
Directional Bore	Addl $8.80/ft		$ 53.15		$ 104.21		$ 182.17
Non-Residential							
Gas Only	$ 42.90		$ 17.13		$ 54.01		$ 61.58
Joint	$ 25.60		$ 22.49		$ 68.13		$ 44.66
Directional Bore	Addl $8.80/ft		$ 53.15		$ 104.21		$ 182.17

Residential		Allowable Footage		
Category		Gas Only		Joint
	Primary 250	158		227
	Primary 425	544		672
	Primary 800	1071		1278
	Seasonal	0		24
	Mobile Home	52		105

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Re-cap - Why No Change for 2022?

- ***COVID Impacts in 2020/2021***
  - *Out of normal construction practices from previous years*
    - *Review of the new normal, how this impacts costs*
  - *In Support of Providing an exceptional customer experience*
    - *Hold off on rate increase during unprecedented times*
- ***2022 will be a transition year for the model***
  - *Existing model is approx. 20 years old*
    - *Outdated software*
    - *Manual data pulls, scrubbing and calculations*
    - *3 different software tools used to provide analysis*
  - *New Model being built in 2022*
    - *Using Current software technology thru a .NET application*
      - *Ability to be enhanced as technology evolves*
    - *Updating assumptions based on data analysis and current construction practices*
    - *Synced to Company Data Tables*
      - *Consistent data structure through query of data tables*
      - *Calculations built into software to provide analysis for leadership*
      - *Simple structure for updating costs through analysis*
    - *1 tool, 1 set of data, 1 analysis with options/recommendations based on data for rate adjustments*

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Current CAP Assumptions

- ***Tariff C8 Customer Attachment Program***
  - *Model Assumptions to review*
    - *Incremental Revenue*
      - *Residential - Fixed table from study completed over 20 years ago*
    - *Incremental Costs*
      - *Plant in Service*
        - » *Determined by 3-year average costs (Service/Main) Size and installation method*

Status of Incremental Revenue Assumptions

- ***Data Analysis***
  - *Building Report View of all customer consumptions from Aug 2021 – July 2022*
    - *Completed*
      - *Consumption Data identified and included (monthly/Sum to annual)*
      - *Customer Location Data identified and included (city/county)*
      - *Number of installations per premise included (quantity to determine if single family home or multi unit)*
      - *Customer Rate Code data*
    - *In Progress*
      - *Customer Meter Size and Meter Location*
      - *Date of installation or date of contract account/decision on Removal of no usage from average*
  - *Report Query will be set up to pull based on a range in time to reduce size of data set*
  - *Report will be run annually to determine if incremental revenues applied should be adjusted*
  - *Views will be built to view data in different slices*
    - *(previous 12 months/3 year average) In Progress*
      - *Average consumption during heating season for each rate/meter size*
      - *Average consumption yearly for each rate/meter size*

- ***Data analysis will help us better understand assumptions and any potential updates that are needed***

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Status of Incremental Cost Assumptions

- ***Pulling data to review Cost Variability***
  - *Joint and non joint*
  - *Installation Method (trench, boring, plowing etc.)*
  - *Timing of installation (spring, summer, winter)*
  - *Contractors (contracts change) and internal crews*
  - *Variability in Volume of pipe installed year over year*
  - *Restoration costs in right of way*
  - *Location of installation and difficulty installing*
- *Cost variables will help determine the time period for an average cost*

- ***Data analysis will help us better understand assumptions and any potential updates that are needed***

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Questions?

Table provides the average year services were installed that have been retired 2020 through 2024.

Line No.		(b)	(c)	(d)	(e)		
1	**Column Labels**						
Year Retired		**2020**	**2021**	**2022**	**2023**	**2024**	**Grand Total**
Average Year Installed	**Average of vintage_year**	**1980**	**1981**	**1983**	**1984**	**1982**	**1982**

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41984928	GRET	SVC	7/11/2024	1946	RET ABN	UG-SERVICE
36424940	GRET	SVC	6/9/2020	1946	RET ABN	UG-SERVICE
42706660	GRET	SVC	6/28/2024	1946	RET ABN	UG-SERVICE
40545195	GRET	SVC	8/9/2023	1946	RET ABN	UG-SERVICE
43526517	GRET	SVC	10/1/2024	1946	RET ABN	UG-SERVICE
42957323	GRET	SVC	9/19/2024	1946	RET ABN	UG-SERVICE
36204404	GRET	SVC	4/25/2020	1946	RET ABN	UG-SERVICE
36260073	GRET	SVC	3/19/2020	1947	RET ABN	UG-SERVICE
38879760	GRET	SVC	8/5/2021	1947	RET ABN	UG-SERVICE
43675355	GRET	SVC	10/3/2024	1947	RET ABN	UG-SERVICE
36559270	GRET	SVC	6/5/2020	1947	RET ABN	UG-SERVICE
42916576	GRET	SVC	9/25/2024	1947	RET ABN	UG-SERVICE
42916546	GRET	SVC	9/25/2024	1947	RET ABN	UG-SERVICE
38604503	GRET	SVC	7/7/2021	1947	RET ABN	UG-SERVICE
38346172	GRET	SVC	5/11/2021	1947	RET ABN	UG-SERVICE
38451808	GRET	SVC	5/7/2021	1947	RET ABN	UG-SERVICE
39417319	GRET	SVC	11/15/2021	1947	RET ABN	UG-SERVICE
37810140	GRET	SVC	11/24/2020	1947	RET ABN	UG-SERVICE
42524677	GRET	SVC	12/28/2023	1947	RET ABN	UG-SERVICE
41006553	GRET	SVC	12/9/2022	1947	RET ABN	UG-SERVICE
36748684	GRET	SVC	8/10/2020	1947	RET ABN	UG-SERVICE
41082588	GRET	SVC	2/2/2023	1947	RET ABN	UG-SERVICE
38550268	GRET	SVC	6/30/2021	1947	RET ABN	UG-SERVICE
40637090	GRET	SVC	8/31/2022	1947	RET ABN	UG-SERVICE
36699368	GRET	SVC	7/27/2020	1947	RET ABN	UG-SERVICE
42524180	GRET	SVC	12/29/2023	1947	RET ABN	UG-SERVICE
38365407	GRET	SVC	4/12/2021	1947	RET ABN	UG-SERVICE
38635342	GRET	SVC	6/21/2021	1947	RET ABN	UG-SERVICE
42815797	GRET	SVC	3/13/2024	1947	RET ABN	UG-SERVICE
43459021	GRET	SVC	8/20/2024	1947	RET ABN	UG-SERVICE
42957426	GRET	SVC	9/19/2024	1948	RET ABN	UG-SERVICE
41669690	GRET	SVC	5/24/2023	1948	RET ABN	UG-SERVICE
38175695	GRET	SVC	3/1/2021	1948	RET ABN	UG-SERVICE
39362214	GRET	SVC	11/1/2021	1948	RET ABN	UG-SERVICE
36028589	GRET	SVC	3/5/2020	1948	RET ABN	UG-SERVICE
38185300	GRET	SVC	2/27/2021	1948	RET ABN	UG-SERVICE
36109958	GRET	SVC	4/22/2020	1948	RET ABN	UG-SERVICE
39791769	GRET	SVC	10/7/2021	1948	RET ABN	UG-SERVICE
40564659	GRET	SVC	1/9/2023	1948	RET ABN	UG-SERVICE
42518406	GRET	SVC	12/28/2023	1948	RET ABN	UG-SERVICE
41241359	GRET	SVC	3/1/2023	1948	RET ABN	UG-SERVICE
38593716	GRET	SVC	6/23/2021	1948	RET ABN	UG-SERVICE
42481127	GRET	SVC	12/20/2023	1948	RET ABN	UG-SERVICE
36947693	GRET	SVC	9/18/2020	1948	RET ABN	UG-SERVICE
42213835	GRET	SVC	10/26/2023	1948	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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42587237	GRET	SVC	9/25/2024	1948	RET ABN	UG-SERVICE
41082944	GRET	SVC	2/2/2023	1948	RET ABN	UG-SERVICE
43715957	GRET	SVC	10/4/2024	1948	RET ABN	UG-SERVICE
32769563	GRET	SVC	7/8/2020	1948	RET ABN	UG-SERVICE
41427677	GRET	SVC	4/14/2023	1948	RET ABN	UG-SERVICE
36120608	GRET	SVC	11/5/2020	1948	RET ABN	UG-SERVICE
38089277	GRET	SVC	2/3/2021	1948	RET ABN	UG-SERVICE
39066726	GRET	SVC	9/27/2021	1948	RET ABN	UG-SERVICE
39423756	GRET	SVC	6/27/2022	1948	RET ABN	UG-SERVICE
37979767	GRET	SVC	1/5/2021	1948	RET ABN	UG-SERVICE
36100989	GRET	SVC	3/10/2020	1948	RET ABN	UG-SERVICE
36040593	GRET	SVC	2/18/2020	1948	RET ABN	UG-SERVICE
38851928	GRET	SVC	11/8/2021	1948	RET ABN	UG-SERVICE
36240447	GRET	SVC	4/29/2020	1948	RET ABN	UG-SERVICE
43184801	GRET	SVC	6/17/2024	1949	RET ABN	UG-SERVICE
40508724	GRET	SVC	9/23/2022	1949	RET ABN	UG-SERVICE
40837783	GRET	SVC	10/17/2022	1949	RET ABN	UG-SERVICE
38097111	GRET	SVC	9/2/2021	1949	RET ABN	UG-SERVICE
42264554	GRET	SVC	10/23/2023	1949	RET ABN	UG-SERVICE
42506606	GRET	SVC	3/28/2024	1949	RET ABN	UG-SERVICE
37593735	GRET	SVC	11/23/2020	1949	RET ABN	UG-SERVICE
38581221	GRET	SVC	8/24/2021	1949	RET ABN	UG-SERVICE
38664596	GRET	SVC	6/24/2021	1949	RET ABN	UG-SERVICE
41194275	GRET	SVC	1/23/2023	1949	RET ABN	UG-SERVICE
36102515	GRET	SVC	4/23/2020	1949	RET ABN	UG-SERVICE
43360848	GRET	SVC	7/29/2024	1949	RET ABN	UG-SERVICE
42337562	GRET	SVC	11/6/2023	1949	RET ABN	UG-SERVICE
40782283	GRET	SVC	11/7/2022	1949	RET ABN	UG-SERVICE
41209796	GRET	SVC	12/11/2023	1949	RET ABN	UG-SERVICE
35962536	GRET	SVC	1/29/2020	1949	RET ABN	UG-SERVICE
36107368	GRET	SVC	4/23/2020	1949	RET ABN	UG-SERVICE
38484519	GRET	SVC	5/12/2021	1949	RET ABN	UG-SERVICE
37031968	GRET	SVC	10/7/2020	1949	RET ABN	UG-SERVICE
38202573	GRET	SVC	3/9/2021	1949	RET ABN	UG-SERVICE
42360719	GRET	SVC	11/15/2023	1949	RET ABN	UG-SERVICE
38451952	GRET	SVC	3/24/2021	1949	RET ABN	UG-SERVICE
40395242	GRET	SVC	7/7/2022	1949	RET ABN	UG-SERVICE
40216874	GRET	SVC	6/7/2022	1949	RET ABN	UG-SERVICE
38165419	GRET	SVC	11/9/2021	1949	RET ABN	UG-SERVICE
32769560	GRET	SVC	7/8/2020	1949	RET ABN	UG-SERVICE
39372955	GRET	SVC	1/25/2022	1949	RET ABN	UG-SERVICE
42587235	GRET	SVC	9/25/2024	1949	RET ABN	UG-SERVICE
37917098	GRET	SVC	12/14/2020	1949	RET ABN	UG-SERVICE
40909882	GRET	SVC	12/20/2022	1949	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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40385383	GRET	SVC	7/17/2022	1949	RET ABN	UG-SERVICE
40973247	GRET	SVC	11/29/2022	1949	RET ABN	UG-SERVICE
42427396	GRET	SVC	9/19/2024	1949	RET ABN	UG-SERVICE
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37084953	GRET	SVC	10/15/2020	1949	RET ABN	UG-SERVICE
42427480	GRET	SVC	9/19/2024	1949	RET ABN	UG-SERVICE
41179277	GRET	SVC	1/19/2023	1950	RET ABN	UG-SERVICE
41873888	GRET	SVC	7/20/2023	1950	RET ABN	UG-SERVICE
37489769	GRET	SVC	11/16/2020	1950	RET ABN	UG-SERVICE
40748066	GRET	SVC	10/15/2022	1950	RET ABN	UG-SERVICE
43245051	GRET	SVC	9/11/2024	1950	RET ABN	UG-SERVICE
38121485	GRET	SVC	2/11/2021	1950	RET ABN	UG-SERVICE
38895091	GRET	SVC	8/17/2021	1950	RET ABN	UG-SERVICE
41968295	GRET	SVC	8/1/2024	1950	RET ABN	UG-SERVICE
38192568	GRET	SVC	3/30/2021	1950	RET ABN	UG-SERVICE
38033940	GRET	SVC	1/20/2021	1950	RET ABN	UG-SERVICE
43338156	GRET	SVC	7/23/2024	1950	RET ABN	UG-SERVICE
40556652	GRET	SVC	8/10/2022	1950	RET ABN	UG-SERVICE
41920885	GRET	SVC	7/31/2023	1950	RET ABN	UG-SERVICE
40644175	GRET	SVC	9/17/2022	1950	RET ABN	UG-SERVICE
40748546	GRET	SVC	9/28/2022	1950	RET ABN	UG-SERVICE
40150854	GRET	SVC	5/18/2022	1950	RET ABN	UG-SERVICE
41411952	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
40749933	GRET	SVC	9/28/2022	1950	RET ABN	UG-SERVICE
39380209	GRET	SVC	11/22/2021	1950	RET ABN	UG-SERVICE
38122135	GRET	SVC	2/11/2021	1950	RET ABN	UG-SERVICE
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43752068	GRET	SVC	12/27/2024	1950	RET ABN	UG-SERVICE
41082593	GRET	SVC	1/4/2023	1950	RET ABN	UG-SERVICE
41015741	GRET	SVC	12/8/2022	1950	RET REM	UG-SERVICE
42550981	GRET	SVC	1/8/2024	1950	RET ABN	UG-SERVICE
42497616	GRET	SVC	12/18/2023	1950	RET ABN	UG-SERVICE
37708593	GRET	SVC	11/25/2020	1950	RET ABN	UG-SERVICE
38146659	GRET	SVC	3/9/2021	1950	RET ABN	UG-SERVICE
41222690	GRET	SVC	2/2/2023	1950	RET REM	UG-SERVICE
43117176	GRET	SVC	6/6/2024	1950	RET ABN	UG-SERVICE
41082587	GRET	SVC	1/9/2023	1950	RET ABN	UG-SERVICE
41036612	GRET	SVC	12/14/2022	1950	RET REM	UG-SERVICE
36371101	GRET	SVC	5/26/2020	1950	RET ABN	UG-SERVICE
41407491	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
37044751	GRET	SVC	10/9/2020	1950	RET ABN	UG-SERVICE
43208932	GRET	SVC	6/24/2024	1950	RET ABN	UG-SERVICE
42604690	GRET	SVC	1/25/2024	1950	RET ABN	UG-SERVICE
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order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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41407382	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
41407777	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
43324300	GRET	SVC	7/26/2024	1950	RET ABN	UG-SERVICE
41064588	GRET	SVC	12/15/2022	1950	RET ABN	UG-SERVICE
36120792	GRET	SVC	11/5/2020	1950	RET ABN	UG-SERVICE
38426623	GRET	SVC	4/26/2021	1950	RET ABN	UG-SERVICE
35871722	GRET	SVC	1/7/2020	1950	RET ABN	UG-SERVICE
41430212	GRET	SVC	9/13/2023	1950	RET ABN	UG-SERVICE
41714290	GRET	SVC	6/5/2023	1950	RET ABN	UG-SERVICE
36030678	GRET	SVC	11/5/2020	1950	RET ABN	UG-SERVICE
39831460	GRET	SVC	8/3/2022	1950	RET ABN	UG-SERVICE
36079297	GRET	SVC	3/2/2020	1950	RET ABN	UG-SERVICE
36245397	GRET	SVC	3/7/2020	1950	RET ABN	UG-SERVICE
43551131	GRET	SVC	9/18/2024	1950	RET ABN	UG-SERVICE
37874484	GRET	SVC	12/4/2020	1950	RET ABN	UG-SERVICE
43522945	GRET	SVC	9/11/2024	1950	RET ABN	UG-SERVICE
43245050	GRET	SVC	9/11/2024	1950	RET ABN	UG-SERVICE
43645279	GRET	SVC	10/4/2024	1950	RET ABN	UG-SERVICE
41407395	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
36113056	GRET	SVC	11/5/2020	1950	RET ABN	UG-SERVICE
43604589	GRET	SVC	9/30/2024	1950	RET ABN	UG-SERVICE
37972672	GRET	SVC	1/2/2021	1950	RET ABN	UG-SERVICE
39348415	GRET	SVC	10/28/2021	1950	RET ABN	UG-SERVICE
42431570	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
38034133	GRET	SVC	1/20/2021	1950	RET ABN	UG-SERVICE
39679450	GRET	SVC	1/12/2022	1950	RET ABN	UG-SERVICE
39791773	GRET	SVC	10/7/2021	1950	RET ABN	UG-SERVICE
43245112	GRET	SVC	9/19/2024	1950	RET ABN	UG-SERVICE
43600705	GRET	SVC	9/19/2024	1950	RET ABN	UG-SERVICE
36712398	GRET	SVC	8/16/2020	1950	RET ABN	UG-SERVICE
41411680	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
43032273	GRET	SVC	4/29/2024	1950	RET ABN	UG-SERVICE
41034947	GRET	SVC	1/12/2023	1950	RET REM	UG-SERVICE
41411269	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
43543490	GRET	SVC	9/30/2024	1950	RET ABN	UG-SERVICE
38561882	GRET	SVC	4/19/2021	1950	RET ABN	UG-SERVICE
41411674	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
38864555	GRET	SVC	6/25/2021	1950	RET ABN	UG-SERVICE
41411918	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
37016175	GRET	SVC	9/30/2020	1950	RET ABN	UG-SERVICE
36235919	GRET	SVC	3/8/2021	1950	RET ABN	UG-SERVICE
41407671	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
42209116	GRET	SVC	3/28/2024	1950	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
37918107	GRET	SVC	1/4/2021	1950	RET ABN	UG-SERVICE
43060517	GRET	SVC	5/16/2024	1950	RET ABN	UG-SERVICE
39831397	GRET	SVC	8/3/2022	1950	RET ABN	UG-SERVICE
41411676	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
39665946	GRET	SVC	8/3/2022	1950	RET ABN	UG-SERVICE
41411422	GRET	SVC	11/2/2023	1950	RET ABN	UG-SERVICE
36348136	GRET	SVC	5/19/2020	1950	RET ABN	UG-SERVICE
36194898	GRET	SVC	5/7/2020	1950	RET ABN	UG-SERVICE
41411672	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
38033805	GRET	SVC	1/21/2021	1950	RET ABN	UG-SERVICE
41407398	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
39247044	GRET	SVC	10/11/2021	1950	RET ABN	UG-SERVICE
36203838	GRET	SVC	4/22/2020	1950	RET ABN	UG-SERVICE
38034050	GRET	SVC	1/20/2021	1950	RET ABN	UG-SERVICE
38414186	GRET	SVC	4/29/2021	1950	RET ABN	UG-SERVICE
41064589	GRET	SVC	12/15/2022	1950	RET ABN	UG-SERVICE
36270604	GRET	SVC	5/6/2020	1950	RET ABN	UG-SERVICE
40802654	GRET	SVC	10/14/2022	1950	RET ABN	UG-SERVICE
38614330	GRET	SVC	6/21/2021	1950	RET ABN	UG-SERVICE
39828249	GRET	SVC	3/16/2022	1950	RET ABN	UG-SERVICE
40523707	GRET	SVC	8/9/2022	1950	RET ABN	UG-SERVICE
43032275	GRET	SVC	4/29/2024	1950	RET ABN	UG-SERVICE
41411671	GRET	SVC	4/2/2024	1950	RET ABN	UG-SERVICE
38062034	GRET	SVC	1/28/2021	1951	RET ABN	UG-SERVICE
38489221	GRET	SVC	5/28/2021	1951	RET ABN	UG-SERVICE
38185531	GRET	SVC	3/1/2021	1951	RET ABN	UG-SERVICE
36739921	GRET	SVC	8/3/2020	1951	RET ABN	UG-SERVICE
36590739	GRET	SVC	7/8/2020	1951	RET ABN	UG-SERVICE
40861220	GRET	SVC	10/24/2022	1951	RET ABN	UG-SERVICE
36779224	GRET	SVC	8/26/2020	1951	RET ABN	UG-SERVICE
40249192	GRET	SVC	6/7/2022	1951	RET ABN	UG-SERVICE
38312480	GRET	SVC	10/5/2021	1951	RET ABN	UG-SERVICE
38352969	GRET	SVC	2/14/2023	1951	RET ABN	UG-SERVICE
41961169	GRET	SVC	8/8/2023	1951	RET ABN	UG-SERVICE
43928937	GRET	SVC	12/13/2024	1951	RET ABN	UG-SERVICE
37887821	GRET	SVC	12/8/2020	1951	RET ABN	UG-SERVICE
39831386	GRET	SVC	8/3/2022	1951	RET ABN	UG-SERVICE
36085668	GRET	SVC	3/2/2020	1951	RET ABN	UG-SERVICE
40674903	GRET	SVC	9/29/2022	1951	RET ABN	UG-SERVICE
42110067	GRET	SVC	12/20/2023	1951	RET ABN	UG-SERVICE
41006869	GRET	SVC	12/7/2022	1951	RET ABN	UG-SERVICE
42435910	GRET	SVC	9/19/2024	1951	RET ABN	UG-SERVICE
40252646	GRET	SVC	6/6/2022	1951	RET ABN	UG-SERVICE
40659708	GRET	SVC	9/3/2022	1951	RET ABN	UG-SERVICE
43413518	GRET	SVC	8/13/2024	1951	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39809564	GRET	SVC	8/3/2022	1951	RET ABN	UG-SERVICE
41423885	GRET	SVC	10/18/2023	1951	RET ABN	UG-SERVICE
40036632	GRET	SVC	4/25/2022	1951	RET ABN	UG-SERVICE
41088767	GRET	SVC	12/21/2022	1951	RET ABN	UG-SERVICE
43435495	GRET	SVC	8/21/2024	1951	RET ABN	UG-SERVICE
41769950	GRET	SVC	6/19/2023	1951	RET REM	UG-SERVICE
38162087	GRET	SVC	2/23/2021	1951	RET ABN	UG-SERVICE
43155106	GRET	SVC	6/3/2024	1951	RET ABN	UG-SERVICE
38707596	GRET	SVC	7/9/2021	1951	RET ABN	UG-SERVICE
38441555	GRET	SVC	1/6/2022	1951	RET ABN	UG-SERVICE
37919597	GRET	SVC	4/8/2021	1951	RET ABN	UG-SERVICE
41411439	GRET	SVC	11/2/2023	1951	RET ABN	UG-SERVICE
41556233	GRET	SVC	4/24/2023	1951	RET ABN	UG-SERVICE
41430213	GRET	SVC	9/19/2023	1951	RET ABN	UG-SERVICE
42150880	GRET	SVC	9/25/2023	1951	RET ABN	UG-SERVICE
43156895	GRET	SVC	7/5/2024	1951	RET ABN	UG-SERVICE
41423887	GRET	SVC	10/18/2023	1951	RET ABN	UG-SERVICE
38423237	GRET	SVC	4/26/2021	1951	RET ABN	UG-SERVICE
43614251	GRET	SVC	9/28/2024	1951	RET ABN	UG-SERVICE
39417387	GRET	SVC	11/14/2021	1951	RET ABN	UG-SERVICE
42538136	GRET	SVC	1/3/2024	1951	RET ABN	UG-SERVICE
41660348	GRET	SVC	5/24/2023	1951	RET ABN	UG-SERVICE
38164753	GRET	SVC	2/24/2021	1951	RET ABN	UG-SERVICE
38567744	GRET	SVC	6/7/2021	1951	RET ABN	UG-SERVICE
36760765	GRET	SVC	8/11/2020	1951	RET ABN	UG-SERVICE
40249164	GRET	SVC	6/10/2022	1951	RET ABN	UG-SERVICE
41034692	GRET	SVC	12/16/2022	1951	RET ABN	UG-SERVICE
38000817	GRET	SVC	1/13/2021	1951	RET ABN	UG-SERVICE
41832368	GRET	SVC	7/7/2023	1951	RET ABN	UG-SERVICE
40989881	GRET	SVC	11/17/2022	1951	RET REM	UG-SERVICE
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41031343	GRET	SVC	12/9/2022	1951	RET ABN	UG-SERVICE
41071955	GRET	SVC	1/3/2023	1951	RET ABN	UG-SERVICE
43905357	GRET	SVC	12/9/2024	1951	RET ABN	UG-SERVICE
41700174	GRET	SVC	5/30/2023	1951	RET ABN	UG-SERVICE
36148001	GRET	SVC	3/14/2020	1951	RET ABN	UG-SERVICE
42152819	GRET	SVC	9/25/2023	1951	RET ABN	UG-SERVICE
39809563	GRET	SVC	8/3/2022	1951	RET ABN	UG-SERVICE
40258718	GRET	SVC	6/6/2022	1951	RET ABN	UG-SERVICE
41013436	GRET	SVC	12/7/2022	1951	RET ABN	UG-SERVICE
39230073	GRET	SVC	10/26/2021	1951	RET ABN	UG-SERVICE
43867865	GRET	SVC	12/30/2024	1951	RET ABN	UG-SERVICE
39719134	GRET	SVC	1/25/2022	1951	RET ABN	UG-SERVICE
40249360	GRET	SVC	6/6/2022	1951	RET ABN	UG-SERVICE
36206659	GRET	SVC	4/23/2020	1951	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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40644729	GRET	SVC	8/31/2022	1951	RET ABN	UG-SERVICE
39706229	GRET	SVC	2/28/2022	1951	RET ABN	UG-SERVICE
40249057	GRET	SVC	6/7/2022	1951	RET ABN	UG-SERVICE
42269957	GRET	SVC	10/23/2023	1951	RET ABN	UG-SERVICE
39424067	GRET	SVC	6/27/2022	1951	RET ABN	UG-SERVICE
39772866	GRET	SVC	9/29/2021	1951	RET ABN	UG-SERVICE
39791768	GRET	SVC	10/6/2021	1951	RET ABN	UG-SERVICE
40989592	GRET	SVC	11/17/2022	1951	RET ABN	UG-SERVICE
37013066	GRET	SVC	10/20/2020	1951	RET ABN	UG-SERVICE
40610203	GRET	SVC	9/17/2022	1951	RET ABN	UG-SERVICE
36952791	GRET	SVC	9/16/2020	1951	RET ABN	UG-SERVICE
38463323	GRET	SVC	5/11/2021	1951	RET ABN	UG-SERVICE
38551597	GRET	SVC	6/2/2021	1951	RET ABN	UG-SERVICE
38161416	GRET	SVC	2/23/2021	1951	RET ABN	UG-SERVICE
41408014	GRET	SVC	4/2/2024	1951	RET ABN	UG-SERVICE
41854515	GRET	SVC	7/10/2023	1951	RET ABN	UG-SERVICE
42575676	GRET	SVC	1/18/2024	1952	RET ABN	UG-SERVICE
38538827	GRET	SVC	5/25/2021	1952	RET ABN	UG-SERVICE
42427487	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
41712850	GRET	SVC	5/22/2023	1952	RET ABN	UG-SERVICE
38595484	GRET	SVC	6/21/2021	1952	RET ABN	UG-SERVICE
41411264	GRET	SVC	4/2/2024	1952	RET ABN	UG-SERVICE
40636684	GRET	SVC	8/30/2022	1952	RET ABN	UG-SERVICE
42683248	GRET	SVC	2/13/2024	1952	RET ABN	UG-SERVICE
42742352	GRET	SVC	8/5/2024	1952	RET ABN	UG-SERVICE
39847796	GRET	SVC	3/8/2022	1952	RET ABN	UG-SERVICE
43231361	GRET	SVC	7/8/2024	1952	RET ABN	UG-SERVICE
39831205	GRET	SVC	8/3/2022	1952	RET ABN	UG-SERVICE
41258769	GRET	SVC	2/6/2023	1952	RET ABN	UG-SERVICE
43245091	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
38352923	GRET	SVC	2/17/2023	1952	RET ABN	UG-SERVICE
38655789	GRET	SVC	6/22/2021	1952	RET ABN	UG-SERVICE
37112877	GRET	SVC	10/26/2020	1952	RET ABN	UG-SERVICE
39666152	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
36809920	GRET	SVC	8/20/2020	1952	RET ABN	UG-SERVICE
42427488	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
39666241	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
39920968	GRET	SVC	4/14/2022	1952	RET ABN	UG-SERVICE
39666246	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
39831210	GRET	SVC	8/3/2022	1952	RET ABN	UG-SERVICE
43240552	GRET	SVC	7/13/2024	1952	RET ABN	UG-SERVICE
39831209	GRET	SVC	8/3/2022	1952	RET ABN	UG-SERVICE
38097358	GRET	SVC	9/2/2021	1952	RET ABN	UG-SERVICE
38097624	GRET	SVC	9/2/2021	1952	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38240752	GRET	SVC	3/24/2021	1952	RET ABN	UG-SERVICE
42427490	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
43423336	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
42226875	GRET	SVC	10/16/2023	1952	RET ABN	UG-SERVICE
40447663	GRET	SVC	7/21/2022	1952	RET ABN	UG-SERVICE
38775680	GRET	SVC	8/15/2021	1952	RET ABN	UG-SERVICE
38352925	GRET	SVC	2/17/2023	1952	RET ABN	UG-SERVICE
39384910	GRET	SVC	11/4/2021	1952	RET ABN	UG-SERVICE
38432093	GRET	SVC	5/5/2021	1952	RET ABN	UG-SERVICE
42252864	GRET	SVC	10/31/2023	1952	RET ABN	UG-SERVICE
42427489	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
39666243	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
40903399	GRET	SVC	11/7/2022	1952	RET ABN	UG-SERVICE
38356733	GRET	SVC	2/14/2023	1952	RET ABN	UG-SERVICE
38610609	GRET	SVC	8/2/2021	1952	RET ABN	UG-SERVICE
36122516	GRET	SVC	11/5/2020	1952	RET ABN	UG-SERVICE
42250860	GRET	SVC	10/20/2023	1952	RET ABN	UG-SERVICE
41731558	GRET	SVC	6/10/2023	1952	RET ABN	UG-SERVICE
41277503	GRET	SVC	2/13/2023	1952	RET REM	UG-SERVICE
39666249	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
42427492	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
43245092	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
39831211	GRET	SVC	8/3/2022	1952	RET ABN	UG-SERVICE
40813279	GRET	SVC	10/14/2022	1952	RET ABN	UG-SERVICE
41407597	GRET	SVC	4/2/2024	1952	RET ABN	UG-SERVICE
38352926	GRET	SVC	2/14/2023	1952	RET ABN	UG-SERVICE
42956741	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
41283744	GRET	SVC	2/13/2023	1952	RET ABN	UG-SERVICE
39666242	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
40473796	GRET	SVC	7/25/2022	1952	RET ABN	UG-SERVICE
41121720	GRET	SVC	1/4/2023	1952	RET ABN	UG-SERVICE
38162089	GRET	SVC	2/23/2021	1952	RET ABN	UG-SERVICE
43245098	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
38073256	GRET	SVC	2/1/2021	1952	RET ABN	UG-SERVICE
38352935	GRET	SVC	2/17/2023	1952	RET ABN	UG-SERVICE
41424766	GRET	SVC	10/18/2023	1952	RET ABN	UG-SERVICE
38352934	GRET	SVC	2/17/2023	1952	RET ABN	UG-SERVICE
43477225	GRET	SVC	12/19/2024	1952	RET ABN	UG-SERVICE
38441456	GRET	SVC	1/6/2022	1952	RET ABN	UG-SERVICE
40919620	GRET	SVC	11/29/2022	1952	RET ABN	UG-SERVICE
42427494	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
42555260	GRET	SVC	3/25/2024	1952	RET ABN	UG-SERVICE
38958979	GRET	SVC	8/30/2021	1952	RET ABN	UG-SERVICE
43241923	GRET	SVC	7/27/2024	1952	RET ABN	UG-SERVICE
42278991	GRET	SVC	10/25/2023	1952	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40632169	GRET	SVC	8/29/2022	1952	RET ABN	UG-SERVICE
42670289	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
36260063	GRET	SVC	3/18/2020	1952	RET ABN	UG-SERVICE
42141042	GRET	SVC	9/18/2023	1952	RET ABN	UG-SERVICE
39940806	GRET	SVC	5/11/2022	1952	RET ABN	UG-SERVICE
36122285	GRET	SVC	11/5/2020	1952	RET ABN	UG-SERVICE
38356730	GRET	SVC	2/17/2023	1952	RET ABN	UG-SERVICE
38280107	GRET	SVC	3/27/2021	1952	RET ABN	UG-SERVICE
38352924	GRET	SVC	2/17/2023	1952	RET ABN	UG-SERVICE
42427491	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
38352936	GRET	SVC	2/17/2023	1952	RET ABN	UG-SERVICE
38356732	GRET	SVC	2/14/2023	1952	RET ABN	UG-SERVICE
38289767	GRET	SVC	4/1/2021	1952	RET ABN	UG-SERVICE
39666155	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
36136809	GRET	SVC	3/16/2020	1952	RET ABN	UG-SERVICE
36119732	GRET	SVC	8/31/2020	1952	RET ABN	UG-SERVICE
40031651	GRET	SVC	4/18/2022	1952	RET ABN	UG-SERVICE
42957680	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
38387047	GRET	SVC	4/23/2021	1952	RET ABN	UG-SERVICE
39230563	GRET	SVC	10/4/2021	1952	RET ABN	UG-SERVICE
36840536	GRET	SVC	9/11/2020	1952	RET ABN	UG-SERVICE
36754616	GRET	SVC	8/12/2020	1952	RET ABN	UG-SERVICE
43598920	GRET	SVC	9/26/2024	1952	RET ABN	UG-SERVICE
41407673	GRET	SVC	4/2/2024	1952	RET ABN	UG-SERVICE
38183688	GRET	SVC	2/16/2021	1952	RET ABN	UG-SERVICE
42455922	GRET	SVC	12/11/2023	1952	RET ABN	UG-SERVICE
42427493	GRET	SVC	9/19/2024	1952	RET ABN	UG-SERVICE
41407596	GRET	SVC	4/2/2024	1952	RET ABN	UG-SERVICE
43661022	GRET	SVC	10/7/2024	1952	RET ABN	UG-SERVICE
40639165	GRET	SVC	9/26/2022	1952	RET ABN	UG-SERVICE
41398652	GRET	SVC	3/30/2023	1952	RET REM	UG-SERVICE
39666252	GRET	SVC	11/18/2022	1952	RET ABN	UG-SERVICE
36432857	GRET	SVC	6/9/2020	1952	RET ABN	UG-SERVICE
41052702	GRET	SVC	1/12/2023	1953	RET ABN	UG-SERVICE
38608396	GRET	SVC	10/19/2021	1953	RET ABN	UG-SERVICE
38190518	GRET	SVC	3/4/2021	1953	RET ABN	UG-SERVICE
38571055	GRET	SVC	6/11/2021	1953	RET ABN	UG-SERVICE
36122585	GRET	SVC	10/4/2020	1953	RET ABN	UG-SERVICE
39993535	GRET	SVC	4/11/2022	1953	RET ABN	UG-SERVICE
41052321	GRET	SVC	1/12/2023	1953	RET ABN	UG-SERVICE
42116065	GRET	SVC	9/29/2023	1953	RET ABN	UG-SERVICE
38507888	GRET	SVC	5/21/2021	1953	RET ABN	UG-SERVICE
38097113	GRET	SVC	9/2/2021	1953	RET ABN	UG-SERVICE
42138181	GRET	SVC	9/21/2023	1953	RET ABN	UG-SERVICE
43637311	GRET	SVC	10/8/2024	1953	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41121802	GRET	SVC	1/6/2023	1953	RET ABN	UG-SERVICE
38582467	GRET	SVC	6/9/2021	1953	RET ABN	UG-SERVICE
38571059	GRET	SVC	6/11/2021	1953	RET ABN	UG-SERVICE
40158955	GRET	SVC	5/12/2022	1953	RET ABN	UG-SERVICE
35873808	GRET	SVC	1/8/2020	1953	RET ABN	UG-SERVICE
35850630	GRET	SVC	1/4/2020	1953	RET ABN	UG-SERVICE
42051188	GRET	SVC	12/22/2023	1953	RET ABN	UG-SERVICE
42879031	GRET	SVC	3/27/2024	1953	RET ABN	UG-SERVICE
36255947	GRET	SVC	5/12/2020	1953	RET ABN	UG-SERVICE
38461273	GRET	SVC	5/10/2021	1953	RET ABN	UG-SERVICE
36419027	GRET	SVC	6/9/2020	1953	RET ABN	UG-SERVICE
38348120	GRET	SVC	4/22/2021	1953	RET ABN	UG-SERVICE
37032220	GRET	SVC	10/7/2020	1953	RET ABN	UG-SERVICE
38538107	GRET	SVC	5/27/2021	1953	RET ABN	UG-SERVICE
38033861	GRET	SVC	1/20/2021	1953	RET ABN	UG-SERVICE
40327471	GRET	SVC	6/21/2022	1953	RET ABN	UG-SERVICE
38352965	GRET	SVC	2/14/2023	1953	RET ABN	UG-SERVICE
38097152	GRET	SVC	9/2/2021	1953	RET ABN	UG-SERVICE
41320907	GRET	SVC	2/27/2023	1953	RET ABN	UG-SERVICE
42427240	GRET	SVC	9/19/2024	1953	RET ABN	UG-SERVICE
42205143	GRET	SVC	12/22/2023	1953	RET ABN	UG-SERVICE
41292554	GRET	SVC	2/20/2023	1953	RET ABN	UG-SERVICE
36143376	GRET	SVC	3/12/2020	1953	RET ABN	UG-SERVICE
41777457	GRET	SVC	6/15/2023	1953	RET ABN	UG-SERVICE
42957321	GRET	SVC	9/19/2024	1953	RET ABN	UG-SERVICE
37708828	GRET	SVC	11/20/2020	1953	RET ABN	UG-SERVICE
40116164	GRET	SVC	5/2/2022	1953	RET ABN	UG-SERVICE
38165030	GRET	SVC	3/5/2021	1953	RET ABN	UG-SERVICE
38260938	GRET	SVC	12/17/2021	1953	RET ABN	UG-SERVICE
43904395	GRET	SVC	12/30/2024	1953	RET ABN	UG-SERVICE
35737712	GRET	SVC	3/18/2020	1953	RET ABN	UG-SERVICE
41976814	GRET	SVC	7/11/2024	1953	RET ABN	UG-SERVICE
39831398	GRET	SVC	8/3/2022	1953	RET ABN	UG-SERVICE
36119405	GRET	SVC	11/5/2020	1953	RET ABN	UG-SERVICE
42320967	GRET	SVC	4/2/2024	1953	RET ABN	UG-SERVICE
36927452	GRET	SVC	9/12/2020	1953	RET ABN	UG-SERVICE
42069649	GRET	SVC	9/5/2023	1953	RET ABN	UG-SERVICE
39666416	GRET	SVC	11/18/2022	1953	RET ABN	UG-SERVICE
38352966	GRET	SVC	2/14/2023	1953	RET ABN	UG-SERVICE
40572029	GRET	SVC	8/16/2022	1953	RET ABN	UG-SERVICE
36331088	GRET	SVC	5/7/2020	1953	RET ABN	UG-SERVICE
40551928	GRET	SVC	8/9/2022	1953	RET ABN	UG-SERVICE
41107697	GRET	SVC	1/10/2023	1953	RET ABN	UG-SERVICE
37254383	GRET	SVC	9/21/2020	1953	RET ABN	UG-SERVICE
41321705	GRET	SVC	3/2/2023	1953	RET REM	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38515668	GRET	SVC	3/21/2022	1953	RET ABN	UG-SERVICE
36255859	GRET	SVC	7/10/2020	1953	RET ABN	UG-SERVICE
38156952	GRET	SVC	7/30/2021	1953	RET ABN	UG-SERVICE
39925433	GRET	SVC	5/9/2022	1953	RET ABN	UG-SERVICE
42120878	GRET	SVC	9/12/2023	1953	RET ABN	UG-SERVICE
41479994	GRET	SVC	4/10/2023	1953	RET ABN	UG-SERVICE
38441422	GRET	SVC	1/6/2022	1953	RET ABN	UG-SERVICE
36777969	GRET	SVC	8/12/2020	1953	RET ABN	UG-SERVICE
42589741	GRET	SVC	1/25/2024	1953	RET ABN	UG-SERVICE
39666663	GRET	SVC	11/18/2022	1953	RET ABN	UG-SERVICE
36371408	GRET	SVC	5/26/2020	1953	RET ABN	UG-SERVICE
36772130	GRET	SVC	8/12/2020	1953	RET ABN	UG-SERVICE
43762605	GRET	SVC	10/31/2024	1953	RET ABN	UG-SERVICE
40318196	GRET	SVC	6/20/2022	1953	RET ABN	UG-SERVICE
41069780	GRET	SVC	1/5/2023	1953	RET ABN	UG-SERVICE
42506330	GRET	SVC	1/25/2024	1953	RET ABN	UG-SERVICE
40253341	GRET	SVC	6/7/2022	1953	RET ABN	UG-SERVICE
38073115	GRET	SVC	2/2/2021	1953	RET ABN	UG-SERVICE
39227657	GRET	SVC	10/2/2021	1953	RET ABN	UG-SERVICE
39666662	GRET	SVC	11/18/2022	1953	RET ABN	UG-SERVICE
38034130	GRET	SVC	1/20/2021	1953	RET ABN	UG-SERVICE
40832923	GRET	SVC	10/19/2022	1953	RET ABN	UG-SERVICE
38693140	GRET	SVC	5/17/2021	1953	RET ABN	UG-SERVICE
40472927	GRET	SVC	8/8/2022	1953	RET ABN	UG-SERVICE
39786857	GRET	SVC	2/7/2022	1953	RET ABN	UG-SERVICE
36927728	GRET	SVC	9/12/2020	1953	RET ABN	UG-SERVICE
38486528	GRET	SVC	5/11/2021	1953	RET ABN	UG-SERVICE
42575673	GRET	SVC	1/10/2024	1953	RET ABN	UG-SERVICE
41755468	GRET	SVC	6/12/2023	1953	RET ABN	UG-SERVICE
39759258	GRET	SVC	8/13/2021	1953	RET ABN	UG-SERVICE
41480231	GRET	SVC	4/6/2023	1953	RET ABN	UG-SERVICE
40346165	GRET	SVC	6/28/2022	1953	RET ABN	UG-SERVICE
41407740	GRET	SVC	4/2/2024	1953	RET ABN	UG-SERVICE
41162549	GRET	SVC	1/7/2023	1953	RET ABN	UG-SERVICE
36119653	GRET	SVC	10/14/2020	1953	RET ABN	UG-SERVICE
41052701	GRET	SVC	1/12/2023	1953	RET ABN	UG-SERVICE
42077779	GRET	SVC	8/29/2023	1953	RET ABN	UG-SERVICE
42257701	GRET	SVC	10/23/2023	1953	RET ABN	UG-SERVICE
41672044	GRET	SVC	5/26/2023	1953	RET ABN	UG-SERVICE
39753780	GRET	SVC	2/10/2022	1954	RET ABN	UG-SERVICE
40685502	GRET	SVC	9/12/2022	1954	RET ABN	UG-SERVICE
41036610	GRET	SVC	12/15/2022	1954	RET ABN	UG-SERVICE
41119592	GRET	SVC	1/6/2023	1954	RET ABN	UG-SERVICE
41035399	GRET	SVC	12/8/2022	1954	RET ABN	UG-SERVICE
36118838	GRET	SVC	10/12/2020	1954	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38820078	GRET	SVC	7/27/2021	1954	RET ABN	UG-SERVICE
38153952	GRET	SVC	2/22/2021	1954	RET ABN	UG-SERVICE
42741404	GRET	SVC	2/15/2024	1954	RET ABN	UG-SERVICE
40505758	GRET	SVC	8/3/2022	1954	RET ABN	UG-SERVICE
38097645	GRET	SVC	9/2/2021	1954	RET ABN	UG-SERVICE
36771065	GRET	SVC	8/11/2020	1954	RET ABN	UG-SERVICE
40919859	GRET	SVC	11/15/2022	1954	RET ABN	UG-SERVICE
36992554	GRET	SVC	10/2/2020	1954	RET ABN	UG-SERVICE
41017133	GRET	SVC	12/5/2022	1954	RET ABN	UG-SERVICE
41411270	GRET	SVC	4/2/2024	1954	RET ABN	UG-SERVICE
39546358	GRET	SVC	1/3/2022	1954	RET ABN	UG-SERVICE
36135000	GRET	SVC	3/16/2020	1954	RET ABN	UG-SERVICE
36136116	GRET	SVC	4/20/2020	1954	RET ABN	UG-SERVICE
41831454	GRET	SVC	7/6/2023	1954	RET ABN	UG-SERVICE
43086584	GRET	SVC	6/5/2024	1954	RET ABN	UG-SERVICE
38545096	GRET	SVC	4/10/2021	1954	RET ABN	UG-SERVICE
39657146	GRET	SVC	6/28/2022	1954	RET ABN	UG-SERVICE
36112441	GRET	SVC	10/12/2020	1954	RET ABN	UG-SERVICE
41411073	GRET	SVC	4/2/2024	1954	RET ABN	UG-SERVICE
41407591	GRET	SVC	4/2/2024	1954	RET ABN	UG-SERVICE
41628218	GRET	SVC	5/18/2023	1954	RET ABN	UG-SERVICE
37088354	GRET	SVC	10/20/2020	1954	RET ABN	UG-SERVICE
39150316	GRET	SVC	9/12/2021	1954	RET ABN	UG-SERVICE
40925026	GRET	SVC	11/15/2022	1954	RET ABN	UG-SERVICE
38572300	GRET	SVC	4/21/2021	1954	RET ABN	UG-SERVICE
40333087	GRET	SVC	6/23/2022	1954	RET ABN	UG-SERVICE
43318165	GRET	SVC	8/13/2024	1954	RET ABN	UG-SERVICE
39666419	GRET	SVC	11/18/2022	1954	RET ABN	UG-SERVICE
41082948	GRET	SVC	1/5/2023	1954	RET ABN	UG-SERVICE
43770278	GRET	SVC	11/21/2024	1954	RET ABN	UG-SERVICE
36868321	GRET	SVC	8/29/2020	1954	RET ABN	UG-SERVICE
40801830	GRET	SVC	10/28/2022	1954	RET ABN	UG-SERVICE
38097643	GRET	SVC	9/2/2021	1954	RET ABN	UG-SERVICE
42115264	GRET	SVC	9/7/2023	1954	RET ABN	UG-SERVICE
41969064	GRET	SVC	8/1/2024	1954	RET ABN	UG-SERVICE
39820961	GRET	SVC	2/22/2022	1954	RET ABN	UG-SERVICE
41407752	GRET	SVC	4/2/2024	1954	RET ABN	UG-SERVICE
38597090	GRET	SVC	6/9/2021	1954	RET ABN	UG-SERVICE
42793388	GRET	SVC	3/25/2024	1954	RET ABN	UG-SERVICE
41817862	GRET	SVC	6/29/2023	1954	RET ABN	UG-SERVICE
41407744	GRET	SVC	4/2/2024	1954	RET ABN	UG-SERVICE
37959606	GRET	SVC	1/8/2021	1954	RET ABN	UG-SERVICE
36112440	GRET	SVC	10/12/2020	1954	RET ABN	UG-SERVICE
38108182	GRET	SVC	12/22/2021	1954	RET ABN	UG-SERVICE
43770740	GRET	SVC	11/21/2024	1954	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43073744	GRET	SVC	5/18/2024	1954	RET ABN	UG-SERVICE
41119744	GRET	SVC	1/6/2023	1954	RET ABN	UG-SERVICE
36348347	GRET	SVC	5/19/2020	1954	RET ABN	UG-SERVICE
41568707	GRET	SVC	4/25/2023	1954	RET ABN	UG-SERVICE
36487887	GRET	SVC	5/11/2020	1954	RET ABN	UG-SERVICE
36914875	GRET	SVC	9/14/2020	1954	RET ABN	UG-SERVICE
43752280	GRET	SVC	12/3/2024	1954	RET ABN	UG-SERVICE
40743846	GRET	SVC	10/10/2022	1954	RET ABN	UG-SERVICE
42451918	GRET	SVC	12/18/2023	1954	RET ABN	UG-SERVICE
36118837	GRET	SVC	5/5/2020	1954	RET ABN	UG-SERVICE
36302202	GRET	SVC	5/5/2020	1954	RET ABN	UG-SERVICE
36119651	GRET	SVC	10/14/2020	1954	RET ABN	UG-SERVICE
40363266	GRET	SVC	6/28/2022	1954	RET ABN	UG-SERVICE
43244747	GRET	SVC	9/13/2024	1954	RET ABN	UG-SERVICE
41411072	GRET	SVC	4/2/2024	1954	RET ABN	UG-SERVICE
43918995	GRET	SVC	12/11/2024	1954	RET ABN	UG-SERVICE
41051913	GRET	SVC	1/12/2023	1954	RET ABN	UG-SERVICE
41659508	GRET	SVC	5/22/2023	1954	RET ABN	UG-SERVICE
36451893	GRET	SVC	6/16/2020	1954	RET ABN	UG-SERVICE
36135788	GRET	SVC	4/21/2020	1954	RET ABN	UG-SERVICE
41423630	GRET	SVC	3/21/2023	1954	RET ABN	UG-SERVICE
41411076	GRET	SVC	4/2/2024	1954	RET ABN	UG-SERVICE
42020389	GRET	SVC	8/21/2023	1954	RET ABN	UG-SERVICE
41477206	GRET	SVC	4/10/2023	1954	RET ABN	UG-SERVICE
35916117	GRET	SVC	1/17/2020	1954	RET ABN	UG-SERVICE
42530677	GRET	SVC	12/20/2023	1954	RET ABN	UG-SERVICE
39666088	GRET	SVC	8/3/2022	1954	RET ABN	UG-SERVICE
42165558	GRET	SVC	9/29/2023	1954	RET ABN	UG-SERVICE
36967051	GRET	SVC	9/23/2020	1954	RET ABN	UG-SERVICE
40906312	GRET	SVC	11/10/2022	1954	RET ABN	UG-SERVICE
39916051	GRET	SVC	4/25/2022	1954	RET ABN	UG-SERVICE
39657155	GRET	SVC	6/28/2022	1954	RET ABN	UG-SERVICE
39830410	GRET	SVC	8/3/2022	1954	RET ABN	UG-SERVICE
37928576	GRET	SVC	1/8/2021	1954	RET ABN	UG-SERVICE
40332153	GRET	SVC	6/22/2022	1954	RET ABN	UG-SERVICE
42416329	GRET	SVC	12/11/2023	1954	RET ABN	UG-SERVICE
38194291	GRET	SVC	3/10/2021	1954	RET ABN	UG-SERVICE
39956460	GRET	SVC	4/5/2022	1955	RET ABN	UG-SERVICE
36906819	GRET	SVC	10/19/2020	1955	RET ABN	UG-SERVICE
40561731	GRET	SVC	10/1/2022	1955	RET ABN	UG-SERVICE
39666053	GRET	SVC	8/3/2022	1955	RET ABN	UG-SERVICE
42201119	GRET	SVC	10/9/2023	1955	RET ABN	UG-SERVICE
41569704	GRET	SVC	4/21/2023	1955	RET ABN	UG-SERVICE
43931698	GRET	SVC	12/11/2024	1955	RET ABN	UG-SERVICE
38135007	GRET	SVC	2/17/2021	1955	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39666496	GRET	SVC	11/18/2022	1955	RET ABN	UG-SERVICE
41407666	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
40883286	GRET	SVC	11/4/2022	1955	RET ABN	UG-SERVICE
40657686	GRET	SVC	9/8/2022	1955	RET ABN	UG-SERVICE
41082591	GRET	SVC	12/21/2022	1955	RET ABN	UG-SERVICE
40113761	GRET	SVC	5/3/2022	1955	RET ABN	UG-SERVICE
43624612	GRET	SVC	10/2/2024	1955	RET ABN	UG-SERVICE
38040115	GRET	SVC	5/20/2021	1955	RET ABN	UG-SERVICE
38658669	GRET	SVC	5/10/2021	1955	RET ABN	UG-SERVICE
36349690	GRET	SVC	5/20/2020	1955	RET ABN	UG-SERVICE
42833735	GRET	SVC	3/19/2024	1955	RET ABN	UG-SERVICE
40754903	GRET	SVC	10/6/2022	1955	RET ABN	UG-SERVICE
41411067	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
42166120	GRET	SVC	9/19/2023	1955	RET ABN	UG-SERVICE
41411836	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
41036616	GRET	SVC	12/15/2022	1955	RET ABN	UG-SERVICE
41601776	GRET	SVC	6/13/2023	1955	RET ABN	UG-SERVICE
41407483	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
41411829	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
41411261	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
42599267	GRET	SVC	2/9/2024	1955	RET ABN	UG-SERVICE
39312779	GRET	SVC	11/23/2021	1955	RET ABN	UG-SERVICE
36433587	GRET	SVC	6/10/2020	1955	RET ABN	UG-SERVICE
42036129	GRET	SVC	8/26/2023	1955	RET ABN	UG-SERVICE
38191944	GRET	SVC	3/10/2021	1955	RET ABN	UG-SERVICE
39710583	GRET	SVC	1/20/2022	1955	RET ABN	UG-SERVICE
42122666	GRET	SVC	9/18/2023	1955	RET ABN	UG-SERVICE
41000447	GRET	SVC	12/2/2022	1955	RET ABN	UG-SERVICE
41411831	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
36185243	GRET	SVC	4/15/2020	1955	RET ABN	UG-SERVICE
39679664	GRET	SVC	1/12/2022	1955	RET ABN	UG-SERVICE
43129636	GRET	SVC	6/3/2024	1955	RET ABN	UG-SERVICE
42180321	GRET	SVC	10/2/2023	1955	RET ABN	UG-SERVICE
40634931	GRET	SVC	10/10/2022	1955	RET ABN	UG-SERVICE
42760744	GRET	SVC	8/1/2024	1955	RET ABN	UG-SERVICE
40802643	GRET	SVC	10/12/2022	1955	RET ABN	UG-SERVICE
41411485	GRET	SVC	11/2/2023	1955	RET ABN	UG-SERVICE
37929847	GRET	SVC	12/17/2020	1955	RET ABN	UG-SERVICE
39759440	GRET	SVC	8/16/2021	1955	RET ABN	UG-SERVICE
39880123	GRET	SVC	3/14/2022	1955	RET ABN	UG-SERVICE
43796684	GRET	SVC	11/13/2024	1955	RET ABN	UG-SERVICE
41411830	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
36193763	GRET	SVC	4/23/2020	1955	RET ABN	UG-SERVICE
40883581	GRET	SVC	11/1/2022	1955	RET ABN	UG-SERVICE
41389200	GRET	SVC	3/15/2023	1955	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36146481	GRET	SVC	5/20/2021	1955	RET ABN	UG-SERVICE
41407760	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
39317626	GRET	SVC	10/25/2021	1955	RET ABN	UG-SERVICE
39830409	GRET	SVC	8/3/2022	1955	RET ABN	UG-SERVICE
39658087	GRET	SVC	3/3/2022	1955	RET ABN	UG-SERVICE
41407542	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
39766735	GRET	SVC	11/2/2021	1955	RET ABN	UG-SERVICE
40691834	GRET	SVC	9/14/2022	1955	RET ABN	UG-SERVICE
41513774	GRET	SVC	4/25/2023	1955	RET ABN	UG-SERVICE
37106589	GRET	SVC	10/27/2020	1955	RET ABN	UG-SERVICE
42032092	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
37053960	GRET	SVC	4/16/2021	1955	RET ABN	UG-SERVICE
41408905	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
41409402	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
41411481	GRET	SVC	11/2/2023	1955	RET ABN	UG-SERVICE
38260281	GRET	SVC	12/14/2021	1955	RET ABN	UG-SERVICE
38210868	GRET	SVC	3/11/2021	1955	RET ABN	UG-SERVICE
41773718	GRET	SVC	6/19/2023	1955	RET ABN	UG-SERVICE
39235481	GRET	SVC	10/10/2021	1955	RET ABN	UG-SERVICE
36098971	GRET	SVC	3/12/2020	1955	RET ABN	UG-SERVICE
42320966	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
41316684	GRET	SVC	2/27/2023	1955	RET ABN	UG-SERVICE
40265913	GRET	SVC	6/8/2022	1955	RET ABN	UG-SERVICE
38731610	GRET	SVC	7/12/2021	1955	RET ABN	UG-SERVICE
41330180	GRET	SVC	3/1/2023	1955	RET ABN	UG-SERVICE
41330183	GRET	SVC	3/2/2023	1955	RET ABN	UG-SERVICE
37108921	GRET	SVC	10/21/2020	1955	RET ABN	UG-SERVICE
41101697	GRET	SVC	1/30/2023	1955	RET ABN	UG-SERVICE
42270344	GRET	SVC	10/25/2023	1955	RET ABN	UG-SERVICE
40754901	GRET	SVC	10/6/2022	1955	RET ABN	UG-SERVICE
41408763	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
36145206	GRET	SVC	12/14/2020	1955	RET ABN	UG-SERVICE
41408902	GRET	SVC	4/2/2024	1955	RET ABN	UG-SERVICE
40113887	GRET	SVC	5/2/2022	1955	RET ABN	UG-SERVICE
32769561	GRET	SVC	7/8/2020	1955	RET ABN	UG-SERVICE
40493095	GRET	SVC	7/25/2022	1955	RET ABN	UG-SERVICE
43244942	GRET	SVC	9/11/2024	1955	RET ABN	UG-SERVICE
40883282	GRET	SVC	11/2/2022	1956	RET ABN	UG-SERVICE
41063358	GRET	SVC	11/30/2022	1956	RET ABN	UG-SERVICE
42850084	GRET	SVC	3/25/2024	1956	RET ABN	UG-SERVICE
38514863	GRET	SVC	8/5/2021	1956	RET ABN	UG-SERVICE
36238532	GRET	SVC	3/2/2020	1956	RET ABN	UG-SERVICE
38573397	GRET	SVC	6/9/2021	1956	RET ABN	UG-SERVICE
41406921	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
39430200	GRET	SVC	11/15/2021	1956	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42205154	GRET	SVC	11/29/2023	1956	RET ABN	UG-SERVICE
38870141	GRET	SVC	8/30/2021	1956	RET ABN	UG-SERVICE
40538000	GRET	SVC	8/28/2022	1956	RET ABN	UG-SERVICE
36107008	GRET	SVC	4/27/2020	1956	RET ABN	UG-SERVICE
40141147	GRET	SVC	5/10/2022	1956	RET ABN	UG-SERVICE
41066002	GRET	SVC	12/13/2022	1956	RET ABN	UG-SERVICE
38310396	GRET	SVC	4/4/2021	1956	RET ABN	UG-SERVICE
41409118	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
40644228	GRET	SVC	9/3/2022	1956	RET ABN	UG-SERVICE
38315075	GRET	SVC	2/26/2021	1956	RET ABN	UG-SERVICE
41510569	GRET	SVC	4/17/2023	1956	RET ABN	UG-SERVICE
42337029	GRET	SVC	11/9/2023	1956	RET ABN	UG-SERVICE
41406991	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
41411754	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
36365097	GRET	SVC	6/2/2020	1956	RET ABN	UG-SERVICE
41031815	GRET	SVC	12/8/2022	1956	RET ABN	UG-SERVICE
38839771	GRET	SVC	8/2/2021	1956	RET ABN	UG-SERVICE
40522615	GRET	SVC	8/5/2022	1956	RET ABN	UG-SERVICE
38966879	GRET	SVC	8/19/2021	1956	RET ABN	UG-SERVICE
41409408	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
40026853	GRET	SVC	4/19/2022	1956	RET ABN	UG-SERVICE
38240750	GRET	SVC	3/26/2021	1956	RET ABN	UG-SERVICE
40360180	GRET	SVC	6/29/2022	1956	RET ABN	UG-SERVICE
41063473	GRET	SVC	1/18/2023	1956	RET ABN	UG-SERVICE
41409404	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
42777461	GRET	SVC	3/1/2024	1956	RET ABN	UG-SERVICE
36177531	GRET	SVC	2/14/2020	1956	RET ABN	UG-SERVICE
41411746	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
41241969	GRET	SVC	2/24/2023	1956	RET ABN	UG-SERVICE
41081183	GRET	SVC	12/20/2022	1956	RET ABN	UG-SERVICE
41408070	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
37958391	GRET	SVC	12/28/2020	1956	RET ABN	UG-SERVICE
42866881	GRET	SVC	3/22/2024	1956	RET ABN	UG-SERVICE
41064595	GRET	SVC	12/13/2022	1956	RET ABN	UG-SERVICE
40279586	GRET	SVC	6/8/2022	1956	RET ABN	UG-SERVICE
41030765	GRET	SVC	12/7/2022	1956	RET ABN	UG-SERVICE
41163173	GRET	SVC	1/13/2023	1956	RET ABN	UG-SERVICE
42817001	GRET	SVC	3/13/2024	1956	RET ABN	UG-SERVICE
35151972	GRET	SVC	1/7/2020	1956	RET ABN	UG-SERVICE
41411747	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
42166672	GRET	SVC	10/14/2023	1956	RET ABN	UG-SERVICE
42247461	GRET	SVC	11/6/2023	1956	RET ABN	UG-SERVICE
37990355	GRET	SVC	1/11/2021	1956	RET ABN	UG-SERVICE
36761549	GRET	SVC	8/14/2020	1956	RET ABN	UG-SERVICE
42385235	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36839860	GRET	SVC	9/1/2020	1956	RET ABN	UG-SERVICE
40492780	GRET	SVC	8/13/2022	1956	RET ABN	UG-SERVICE
37874343	GRET	SVC	12/7/2020	1956	RET ABN	UG-SERVICE
39830416	GRET	SVC	8/3/2022	1956	RET ABN	UG-SERVICE
36525533	GRET	SVC	6/25/2020	1956	RET ABN	UG-SERVICE
43632871	GRET	SVC	10/2/2024	1956	RET ABN	UG-SERVICE
42435906	GRET	SVC	9/19/2024	1956	RET ABN	UG-SERVICE
41289003	GRET	SVC	3/21/2023	1956	RET ABN	UG-SERVICE
38314238	GRET	SVC	3/24/2021	1956	RET ABN	UG-SERVICE
41441939	GRET	SVC	9/13/2023	1956	RET ABN	UG-SERVICE
39477405	GRET	SVC	11/29/2021	1956	RET ABN	UG-SERVICE
41411182	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
35965175	GRET	SVC	1/30/2020	1956	RET ABN	UG-SERVICE
42018667	GRET	SVC	8/21/2023	1956	RET ABN	UG-SERVICE
38370185	GRET	SVC	4/15/2021	1956	RET ABN	UG-SERVICE
41411907	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
38484125	GRET	SVC	5/14/2021	1956	RET ABN	UG-SERVICE
39817529	GRET	SVC	2/22/2022	1956	RET ABN	UG-SERVICE
41066001	GRET	SVC	1/4/2023	1956	RET ABN	UG-SERVICE
38341484	GRET	SVC	4/10/2021	1956	RET ABN	UG-SERVICE
42964245	GRET	SVC	9/19/2024	1956	RET ABN	UG-SERVICE
36119656	GRET	SVC	10/14/2020	1956	RET ABN	UG-SERVICE
40277552	GRET	SVC	4/27/2023	1956	RET ABN	UG-SERVICE
42844197	GRET	SVC	3/20/2024	1956	RET ABN	UG-SERVICE
37111303	GRET	SVC	10/22/2020	1956	RET ABN	UG-SERVICE
39999273	GRET	SVC	4/14/2022	1956	RET ABN	UG-SERVICE
40389547	GRET	SVC	12/14/2022	1956	RET ABN	UG-SERVICE
36101773	GRET	SVC	4/23/2020	1956	RET ABN	UG-SERVICE
41106883	GRET	SVC	12/30/2022	1956	RET ABN	UG-SERVICE
38813540	GRET	SVC	7/21/2021	1956	RET ABN	UG-SERVICE
41051912	GRET	SVC	1/12/2023	1956	RET ABN	UG-SERVICE
38751617	GRET	SVC	8/5/2021	1956	RET ABN	UG-SERVICE
42208441	GRET	SVC	10/13/2023	1956	RET ABN	UG-SERVICE
36741665	GRET	SVC	8/7/2020	1956	RET ABN	UG-SERVICE
39908142	GRET	SVC	3/21/2022	1956	RET ABN	UG-SERVICE
42373894	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
39772873	GRET	SVC	10/1/2021	1956	RET ABN	UG-SERVICE
42791921	GRET	SVC	3/4/2024	1956	RET ABN	UG-SERVICE
43540093	GRET	SVC	9/23/2024	1956	RET ABN	UG-SERVICE
39827711	GRET	SVC	2/24/2022	1956	RET ABN	UG-SERVICE
43451804	GRET	SVC	8/19/2024	1956	RET ABN	UG-SERVICE
42156401	GRET	SVC	3/28/2024	1956	RET ABN	UG-SERVICE
41411757	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
41408589	GRET	SVC	4/2/2024	1956	RET ABN	UG-SERVICE
40453370	GRET	SVC	7/18/2022	1956	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38793969	GRET	SVC	7/20/2021	1956	RET ABN	UG-SERVICE
38117093	GRET	SVC	2/12/2021	1956	RET ABN	UG-SERVICE
37973593	GRET	SVC	1/5/2021	1956	RET ABN	UG-SERVICE
39092654	GRET	SVC	9/10/2021	1956	RET ABN	UG-SERVICE
39410508	GRET	SVC	11/10/2021	1956	RET ABN	UG-SERVICE
43755541	GRET	SVC	11/9/2024	1957	RET ABN	UG-SERVICE
41424260	GRET	SVC	10/18/2023	1957	RET ABN	UG-SERVICE
41430106	GRET	SVC	9/12/2023	1957	RET ABN	UG-SERVICE
37740415	GRET	SVC	11/21/2020	1957	RET ABN	UG-SERVICE
36137570	GRET	SVC	4/21/2020	1957	RET ABN	UG-SERVICE
41442142	GRET	SVC	9/13/2023	1957	RET ABN	UG-SERVICE
39518727	GRET	SVC	12/10/2021	1957	RET ABN	UG-SERVICE
38881452	GRET	SVC	8/31/2021	1957	RET ABN	UG-SERVICE
39542672	GRET	SVC	12/15/2021	1957	RET ABN	UG-SERVICE
41669838	GRET	SVC	6/17/2023	1957	RET ABN	UG-SERVICE
36267558	GRET	SVC	3/24/2020	1957	RET ABN	UG-SERVICE
36387479	GRET	SVC	7/2/2020	1957	RET ABN	UG-SERVICE
41075020	GRET	SVC	12/21/2022	1957	RET ABN	UG-SERVICE
41068182	GRET	SVC	1/10/2023	1957	RET ABN	UG-SERVICE
41411755	GRET	SVC	4/2/2024	1957	RET ABN	UG-SERVICE
42176690	GRET	SVC	10/3/2023	1957	RET ABN	UG-SERVICE
36598691	GRET	SVC	7/25/2020	1957	RET ABN	UG-SERVICE
41424518	GRET	SVC	10/18/2023	1957	RET ABN	UG-SERVICE
41028795	GRET	SVC	12/6/2022	1957	RET ABN	UG-SERVICE
39806497	GRET	SVC	2/21/2022	1957	RET ABN	UG-SERVICE
41362916	GRET	SVC	3/13/2023	1957	RET ABN	UG-SERVICE
36118917	GRET	SVC	10/30/2020	1957	RET ABN	UG-SERVICE
41807889	GRET	SVC	6/27/2023	1957	RET ABN	UG-SERVICE
40990955	GRET	SVC	12/15/2022	1957	RET ABN	UG-SERVICE
36118832	GRET	SVC	10/14/2020	1957	RET ABN	UG-SERVICE
36102856	GRET	SVC	4/22/2020	1957	RET ABN	UG-SERVICE
41117720	GRET	SVC	1/10/2023	1957	RET ABN	UG-SERVICE
41423884	GRET	SVC	10/18/2023	1957	RET ABN	UG-SERVICE
38599595	GRET	SVC	6/9/2021	1957	RET ABN	UG-SERVICE
35837924	GRET	SVC	8/19/2020	1957	RET ABN	UG-SERVICE
40131343	GRET	SVC	5/17/2022	1957	RET ABN	UG-SERVICE
41442140	GRET	SVC	9/13/2023	1957	RET ABN	UG-SERVICE
36108624	GRET	SVC	4/23/2020	1957	RET ABN	UG-SERVICE
43303826	GRET	SVC	7/11/2024	1957	RET ABN	UG-SERVICE
40137963	GRET	SVC	5/19/2022	1957	RET ABN	UG-SERVICE
39606854	GRET	SVC	4/20/2021	1957	RET ABN	UG-SERVICE
40082004	GRET	SVC	8/24/2022	1957	RET ABN	UG-SERVICE
38568559	GRET	SVC	6/7/2021	1957	RET ABN	UG-SERVICE
41430105	GRET	SVC	9/12/2023	1957	RET ABN	UG-SERVICE
41969457	GRET	SVC	7/30/2024	1957	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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36170363	GRET	SVC	3/24/2020	1957	RET ABN	UG-SERVICE
36119061	GRET	SVC	10/30/2020	1957	RET ABN	UG-SERVICE
37639344	GRET	SVC	11/17/2020	1957	RET ABN	UG-SERVICE
41969454	GRET	SVC	7/30/2024	1957	RET ABN	UG-SERVICE
42898518	GRET	SVC	9/19/2024	1957	RET ABN	UG-SERVICE
36425569	GRET	SVC	5/12/2020	1957	RET ABN	UG-SERVICE
42137717	GRET	SVC	9/21/2023	1957	RET ABN	UG-SERVICE
35838041	GRET	SVC	8/19/2020	1957	RET ABN	UG-SERVICE
36580954	GRET	SVC	7/6/2020	1957	RET ABN	UG-SERVICE
40973890	GRET	SVC	1/24/2023	1957	RET ABN	UG-SERVICE
39578746	GRET	SVC	12/22/2021	1957	RET ABN	UG-SERVICE
38033879	GRET	SVC	1/21/2021	1957	RET ABN	UG-SERVICE
40865909	GRET	SVC	8/22/2023	1957	RET ABN	UG-SERVICE
42995221	GRET	SVC	7/2/2024	1957	RET ABN	UG-SERVICE
43945703	GRET	SVC	12/17/2024	1957	RET ABN	UG-SERVICE
41424355	GRET	SVC	4/2/2023	1957	RET ABN	UG-SERVICE
40583049	GRET	SVC	9/24/2022	1957	RET ABN	UG-SERVICE
41117391	GRET	SVC	1/12/2023	1957	RET ABN	UG-SERVICE
41691783	GRET	SVC	6/2/2023	1957	RET ABN	UG-SERVICE
37183757	GRET	SVC	8/23/2020	1957	RET ABN	UG-SERVICE
39665276	GRET	SVC	8/3/2022	1957	RET ABN	UG-SERVICE
43208433	GRET	SVC	6/25/2024	1957	RET ABN	UG-SERVICE
42247030	GRET	SVC	10/30/2023	1957	RET ABN	UG-SERVICE
41430214	GRET	SVC	9/19/2023	1957	RET ABN	UG-SERVICE
39830526	GRET	SVC	8/3/2022	1957	RET ABN	UG-SERVICE
41287030	GRET	SVC	3/17/2023	1957	RET ABN	UG-SERVICE
38541491	GRET	SVC	5/26/2021	1957	RET ABN	UG-SERVICE
42701509	GRET	SVC	2/14/2024	1957	RET ABN	UG-SERVICE
36121520	GRET	SVC	11/5/2020	1957	RET ABN	UG-SERVICE
37415381	GRET	SVC	10/28/2020	1957	RET ABN	UG-SERVICE
41068186	GRET	SVC	1/21/2023	1957	RET ABN	UG-SERVICE
36118826	GRET	SVC	10/14/2020	1957	RET ABN	UG-SERVICE
41088303	GRET	SVC	1/9/2023	1957	RET ABN	UG-SERVICE
38611656	GRET	SVC	6/10/2021	1957	RET ABN	UG-SERVICE
43621453	GRET	SVC	9/17/2024	1957	RET ABN	UG-SERVICE
43863443	GRET	SVC	11/23/2024	1957	RET ABN	UG-SERVICE
35939239	GRET	SVC	1/28/2020	1957	RET ABN	UG-SERVICE
41036611	GRET	SVC	12/13/2022	1957	RET ABN	UG-SERVICE
42336427	GRET	SVC	4/2/2024	1957	RET ABN	UG-SERVICE
36023387	GRET	SVC	2/17/2020	1957	RET ABN	UG-SERVICE
41430211	GRET	SVC	9/13/2023	1957	RET ABN	UG-SERVICE
41222696	GRET	SVC	2/2/2023	1957	RET ABN	UG-SERVICE
36121611	GRET	SVC	10/30/2020	1957	RET ABN	UG-SERVICE
41401747	GRET	SVC	3/15/2023	1957	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36228629	GRET	SVC	3/8/2021	1957	RET ABN	UG-SERVICE
36303557	GRET	SVC	5/6/2020	1957	RET ABN	UG-SERVICE
41707019	GRET	SVC	6/12/2023	1957	RET ABN	UG-SERVICE
41807579	GRET	SVC	6/28/2023	1957	RET ABN	UG-SERVICE
41409106	GRET	SVC	4/2/2024	1957	RET ABN	UG-SERVICE
41898750	GRET	SVC	7/24/2023	1957	RET ABN	UG-SERVICE
41063474	GRET	SVC	12/17/2022	1957	RET ABN	UG-SERVICE
41424263	GRET	SVC	10/18/2023	1957	RET ABN	UG-SERVICE
39423526	GRET	SVC	6/27/2022	1957	RET ABN	UG-SERVICE
42028594	GRET	SVC	8/24/2023	1957	RET ABN	UG-SERVICE
41513777	GRET	SVC	4/25/2023	1957	RET ABN	UG-SERVICE
41411416	GRET	SVC	11/2/2023	1957	RET ABN	UG-SERVICE
41083730	GRET	SVC	12/21/2022	1957	RET ABN	UG-SERVICE
38352975	GRET	SVC	2/14/2023	1958	RET ABN	UG-SERVICE
41085609	GRET	SVC	1/13/2023	1958	RET ABN	UG-SERVICE
38097172	GRET	SVC	9/2/2021	1958	RET ABN	UG-SERVICE
36245398	GRET	SVC	3/7/2020	1958	RET ABN	UG-SERVICE
37740543	GRET	SVC	11/25/2020	1958	RET ABN	UG-SERVICE
39366490	GRET	SVC	11/4/2021	1958	RET ABN	UG-SERVICE
41408227	GRET	SVC	4/2/2024	1958	RET ABN	UG-SERVICE
38352973	GRET	SVC	2/17/2023	1958	RET ABN	UG-SERVICE
40171770	GRET	SVC	5/17/2022	1958	RET ABN	UG-SERVICE
41411415	GRET	SVC	11/2/2023	1958	RET ABN	UG-SERVICE
41965726	GRET	SVC	8/3/2023	1958	RET ABN	UG-SERVICE
41617607	GRET	SVC	4/27/2023	1958	RET ABN	UG-SERVICE
36347721	GRET	SVC	6/29/2020	1958	RET ABN	UG-SERVICE
41423892	GRET	SVC	10/18/2023	1958	RET ABN	UG-SERVICE
38034501	GRET	SVC	12/6/2020	1958	RET ABN	UG-SERVICE
35887497	GRET	SVC	1/13/2020	1958	RET ABN	UG-SERVICE
36120267	GRET	SVC	10/30/2020	1958	RET ABN	UG-SERVICE
38357049	GRET	SVC	2/17/2023	1958	RET ABN	UG-SERVICE
35995645	GRET	SVC	2/10/2020	1958	RET ABN	UG-SERVICE
41423893	GRET	SVC	10/18/2023	1958	RET ABN	UG-SERVICE
42979658	GRET	SVC	4/26/2024	1958	RET ABN	UG-SERVICE
36106825	GRET	SVC	3/9/2020	1958	RET ABN	UG-SERVICE
41148325	GRET	SVC	1/7/2023	1958	RET ABN	UG-SERVICE
40035442	GRET	SVC	4/20/2022	1958	RET ABN	UG-SERVICE
38522091	GRET	SVC	5/21/2021	1958	RET ABN	UG-SERVICE
36868685	GRET	SVC	8/31/2020	1958	RET ABN	UG-SERVICE
41423894	GRET	SVC	10/18/2023	1958	RET ABN	UG-SERVICE
38474291	GRET	SVC	3/30/2021	1958	RET ABN	UG-SERVICE
42786964	GRET	SVC	3/4/2024	1958	RET ABN	UG-SERVICE
41424762	GRET	SVC	6/20/2023	1958	RET ABN	UG-SERVICE
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38301100	GRET	SVC	3/31/2021	1958	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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42737790	GRET	SVC	2/19/2024	1958	RET ABN	UG-SERVICE
41411414	GRET	SVC	11/2/2023	1958	RET ABN	UG-SERVICE
38970342	GRET	SVC	12/9/2021	1958	RET ABN	UG-SERVICE
41441929	GRET	SVC	9/13/2023	1958	RET ABN	UG-SERVICE
38507101	GRET	SVC	5/3/2021	1958	RET ABN	UG-SERVICE
40460466	GRET	SVC	7/25/2022	1958	RET ABN	UG-SERVICE
38426008	GRET	SVC	4/28/2021	1958	RET ABN	UG-SERVICE
43752107	GRET	SVC	12/10/2024	1958	RET ABN	UG-SERVICE
40432962	GRET	SVC	7/22/2022	1958	RET ABN	UG-SERVICE
36105787	GRET	SVC	2/13/2020	1958	RET ABN	UG-SERVICE
43834420	GRET	SVC	11/18/2024	1958	RET ABN	UG-SERVICE
39493537	GRET	SVC	12/22/2021	1958	RET ABN	UG-SERVICE
38352458	GRET	SVC	6/10/2021	1958	RET ABN	UG-SERVICE
41284186	GRET	SVC	3/15/2023	1958	RET ABN	UG-SERVICE
42656588	GRET	SVC	12/19/2024	1958	RET ABN	UG-SERVICE
43620926	GRET	SVC	9/20/2024	1958	RET ABN	UG-SERVICE
41147849	GRET	SVC	1/9/2023	1958	RET ABN	UG-SERVICE
41051916	GRET	SVC	1/12/2023	1958	RET ABN	UG-SERVICE
35682119	GRET	SVC	1/9/2020	1958	RET ABN	UG-SERVICE
41052320	GRET	SVC	1/12/2023	1958	RET ABN	UG-SERVICE
36086679	GRET	SVC	2/27/2020	1958	RET ABN	UG-SERVICE
39382160	GRET	SVC	11/5/2021	1958	RET ABN	UG-SERVICE
41139506	GRET	SVC	1/9/2023	1958	RET ABN	UG-SERVICE
42847072	GRET	SVC	4/1/2024	1958	RET ABN	UG-SERVICE
43984868	GRET	SVC	12/12/2024	1958	RET ABN	UG-SERVICE
39831388	GRET	SVC	8/3/2022	1958	RET ABN	UG-SERVICE
36120268	GRET	SVC	10/30/2020	1958	RET ABN	UG-SERVICE
43623434	GRET	SVC	11/25/2024	1958	RET ABN	UG-SERVICE
38352968	GRET	SVC	2/14/2023	1958	RET ABN	UG-SERVICE
41411432	GRET	SVC	11/2/2023	1958	RET ABN	UG-SERVICE
39916054	GRET	SVC	5/2/2022	1958	RET ABN	UG-SERVICE
38111180	GRET	SVC	2/9/2021	1958	RET ABN	UG-SERVICE
38352977	GRET	SVC	2/17/2023	1958	RET ABN	UG-SERVICE
37887690	GRET	SVC	12/11/2020	1958	RET ABN	UG-SERVICE
39383979	GRET	SVC	11/9/2021	1958	RET ABN	UG-SERVICE
38352979	GRET	SVC	2/17/2023	1958	RET ABN	UG-SERVICE
36120487	GRET	SVC	10/30/2020	1958	RET ABN	UG-SERVICE
39806834	GRET	SVC	2/16/2022	1958	RET ABN	UG-SERVICE
42586523	GRET	SVC	1/29/2024	1958	RET ABN	UG-SERVICE
36166301	GRET	SVC	3/23/2020	1958	RET ABN	UG-SERVICE
39609259	GRET	SVC	4/27/2021	1958	RET ABN	UG-SERVICE
42915278	GRET	SVC	4/15/2024	1958	RET ABN	UG-SERVICE
36559263	GRET	SVC	6/4/2020	1958	RET ABN	UG-SERVICE
38352976	GRET	SVC	2/17/2023	1958	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38164764	GRET	SVC	2/24/2021	1958	RET ABN	UG-SERVICE
38097177	GRET	SVC	9/2/2021	1958	RET ABN	UG-SERVICE
37386989	GRET	SVC	11/25/2020	1958	RET ABN	UG-SERVICE
39831208	GRET	SVC	8/3/2022	1958	RET ABN	UG-SERVICE
39301096	GRET	SVC	10/20/2021	1958	RET ABN	UG-SERVICE
36658889	GRET	SVC	7/21/2020	1958	RET ABN	UG-SERVICE
38301288	GRET	SVC	5/5/2021	1958	RET ABN	UG-SERVICE
40870148	GRET	SVC	10/28/2022	1958	RET ABN	UG-SERVICE
40318186	GRET	SVC	6/20/2022	1958	RET ABN	UG-SERVICE
36570144	GRET	SVC	7/1/2020	1958	RET ABN	UG-SERVICE
38352972	GRET	SVC	2/17/2023	1958	RET ABN	UG-SERVICE
38089255	GRET	SVC	1/20/2021	1958	RET ABN	UG-SERVICE
40495220	GRET	SVC	7/23/2022	1958	RET ABN	UG-SERVICE
41424763	GRET	SVC	10/18/2023	1958	RET ABN	UG-SERVICE
42957326	GRET	SVC	9/19/2024	1958	RET ABN	UG-SERVICE
41441928	GRET	SVC	9/13/2023	1958	RET ABN	UG-SERVICE
39721554	GRET	SVC	1/28/2022	1958	RET ABN	UG-SERVICE
38357046	GRET	SVC	2/17/2023	1958	RET ABN	UG-SERVICE
41408474	GRET	SVC	4/2/2024	1958	RET ABN	UG-SERVICE
40399649	GRET	SVC	7/15/2022	1958	RET ABN	UG-SERVICE
36107160	GRET	SVC	4/22/2020	1958	RET ABN	UG-SERVICE
36122371	GRET	SVC	11/5/2020	1958	RET ABN	UG-SERVICE
39353523	GRET	SVC	2/15/2022	1958	RET ABN	UG-SERVICE
36149149	GRET	SVC	1/6/2021	1958	RET ABN	UG-SERVICE
43011963	GRET	SVC	4/30/2024	1958	RET ABN	UG-SERVICE
41411413	GRET	SVC	11/2/2023	1958	RET ABN	UG-SERVICE
38205412	GRET	SVC	3/16/2021	1958	RET ABN	UG-SERVICE
43353724	GRET	SVC	11/7/2024	1958	RET ABN	UG-SERVICE
38791176	GRET	SVC	8/2/2021	1958	RET ABN	UG-SERVICE
40492804	GRET	SVC	8/2/2022	1958	RET ABN	UG-SERVICE
41286908	GRET	SVC	3/17/2023	1958	RET ABN	UG-SERVICE
40036424	GRET	SVC	4/20/2022	1958	RET ABN	UG-SERVICE
35958597	GRET	SVC	2/20/2020	1958	RET ABN	UG-SERVICE
36992541	GRET	SVC	9/22/2020	1958	RET ABN	UG-SERVICE
41148327	GRET	SVC	1/7/2023	1958	RET ABN	UG-SERVICE
37948477	GRET	SVC	12/23/2020	1959	RET ABN	UG-SERVICE
41398905	GRET	SVC	3/24/2023	1959	RET ABN	UG-SERVICE
36121341	GRET	SVC	10/30/2020	1959	RET ABN	UG-SERVICE
38659865	GRET	SVC	6/24/2021	1959	RET ABN	UG-SERVICE
40487935	GRET	SVC	7/25/2022	1959	RET ABN	UG-SERVICE
42353965	GRET	SVC	11/14/2023	1959	RET ABN	UG-SERVICE
36893335	GRET	SVC	8/29/2020	1959	RET ABN	UG-SERVICE
39699185	GRET	SVC	1/18/2022	1959	RET ABN	UG-SERVICE
41411078	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
41411074	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43151637	GRET	SVC	7/15/2024	1959	RET ABN	UG-SERVICE
42208445	GRET	SVC	10/13/2023	1959	RET ABN	UG-SERVICE
41408519	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
40172804	GRET	SVC	5/16/2022	1959	RET ABN	UG-SERVICE
43274816	GRET	SVC	7/6/2024	1959	RET ABN	UG-SERVICE
39380921	GRET	SVC	10/21/2021	1959	RET ABN	UG-SERVICE
43377183	GRET	SVC	8/6/2024	1959	RET ABN	UG-SERVICE
37307282	GRET	SVC	11/5/2020	1959	RET REM	UG-SERVICE
37934432	GRET	SVC	12/21/2020	1959	RET ABN	UG-SERVICE
42452951	GRET	SVC	4/26/2024	1959	RET ABN	UG-SERVICE
42168657	GRET	SVC	10/2/2023	1959	RET ABN	UG-SERVICE
36298881	GRET	SVC	5/5/2020	1959	RET ABN	UG-SERVICE
36122368	GRET	SVC	10/30/2020	1959	RET ABN	UG-SERVICE
41409110	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
43346976	GRET	SVC	7/25/2024	1959	RET ABN	UG-SERVICE
41409109	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
41842797	GRET	SVC	7/8/2023	1959	RET ABN	UG-SERVICE
39780203	GRET	SVC	2/11/2022	1959	RET ABN	UG-SERVICE
41544813	GRET	SVC	12/11/2023	1959	RET ABN	UG-SERVICE
38352931	GRET	SVC	2/17/2023	1959	RET ABN	UG-SERVICE
36927908	GRET	SVC	9/17/2020	1959	RET ABN	UG-SERVICE
36121816	GRET	SVC	10/12/2020	1959	RET ABN	UG-SERVICE
37321680	GRET	SVC	12/1/2020	1959	RET ABN	UG-SERVICE
41411901	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
39845055	GRET	SVC	3/4/2022	1959	RET ABN	UG-SERVICE
42670034	GRET	SVC	2/9/2024	1959	RET ABN	UG-SERVICE
36101963	GRET	SVC	3/18/2020	1959	RET ABN	UG-SERVICE
41407232	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
41407210	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
39611979	GRET	SVC	5/27/2021	1959	RET ABN	UG-SERVICE
40858381	GRET	SVC	10/26/2022	1959	RET ABN	UG-SERVICE
41859889	GRET	SVC	8/11/2023	1959	RET ABN	UG-SERVICE
36035810	GRET	SVC	2/15/2020	1959	RET ABN	UG-SERVICE
40490110	GRET	SVC	5/23/2023	1959	RET ABN	UG-SERVICE
41288533	GRET	SVC	3/1/2023	1959	RET ABN	UG-SERVICE
39666420	GRET	SVC	11/18/2022	1959	RET ABN	UG-SERVICE
37249819	GRET	SVC	11/17/2020	1959	RET ABN	UG-SERVICE
38441389	GRET	SVC	1/6/2022	1959	RET ABN	UG-SERVICE
40338701	GRET	SVC	6/21/2022	1959	RET ABN	UG-SERVICE
41007816	GRET	SVC	12/8/2022	1959	RET ABN	UG-SERVICE
41408461	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
40478345	GRET	SVC	7/25/2022	1959	RET ABN	UG-SERVICE
38033756	GRET	SVC	1/22/2021	1959	RET ABN	UG-SERVICE
37019048	GRET	SVC	9/28/2020	1959	RET ABN	UG-SERVICE
42506338	GRET	SVC	1/4/2024	1959	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41273847	GRET	SVC	2/28/2023	1959	RET ABN	UG-SERVICE
36260061	GRET	SVC	3/18/2020	1959	RET ABN	UG-SERVICE
43154437	GRET	SVC	6/10/2024	1959	RET ABN	UG-SERVICE
36254921	GRET	SVC	10/25/2020	1959	RET ABN	UG-SERVICE
36120709	GRET	SVC	10/30/2020	1959	RET ABN	UG-SERVICE
43394312	GRET	SVC	9/19/2024	1959	RET ABN	UG-SERVICE
37869002	GRET	SVC	12/2/2020	1959	RET ABN	UG-SERVICE
42008802	GRET	SVC	8/16/2023	1959	RET ABN	UG-SERVICE
31040393	GRET	SVC	11/10/2022	1959	RET ABN	UG-SERVICE
36336551	GRET	SVC	5/8/2020	1959	RET ABN	UG-SERVICE
39367005	GRET	SVC	11/2/2021	1959	RET ABN	UG-SERVICE
39904815	GRET	SVC	3/24/2022	1959	RET ABN	UG-SERVICE
39745884	GRET	SVC	2/9/2022	1959	RET ABN	UG-SERVICE
42911783	GRET	SVC	4/13/2024	1959	RET ABN	UG-SERVICE
41318360	GRET	SVC	3/3/2023	1959	RET ABN	UG-SERVICE
41411279	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
36168654	GRET	SVC	3/23/2020	1959	RET ABN	UG-SERVICE
43318343	GRET	SVC	8/9/2024	1959	RET ABN	UG-SERVICE
41277882	GRET	SVC	2/13/2023	1959	RET ABN	UG-SERVICE
41407806	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
38594833	GRET	SVC	6/8/2021	1959	RET ABN	UG-SERVICE
41571592	GRET	SVC	5/1/2023	1959	RET ABN	UG-SERVICE
43614177	GRET	SVC	9/25/2024	1959	RET ABN	UG-SERVICE
36609185	GRET	SVC	7/22/2020	1959	RET ABN	UG-SERVICE
41407230	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
38964849	GRET	SVC	9/20/2021	1959	RET ABN	UG-SERVICE
39791766	GRET	SVC	10/5/2021	1959	RET ABN	UG-SERVICE
42752845	GRET	SVC	6/28/2024	1959	RET ABN	UG-SERVICE
41408225	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
43473548	GRET	SVC	8/15/2024	1959	RET ABN	UG-SERVICE
42316686	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
36121809	GRET	SVC	10/12/2020	1959	RET ABN	UG-SERVICE
41116695	GRET	SVC	2/2/2023	1959	RET ABN	UG-SERVICE
41573846	GRET	SVC	5/10/2023	1959	RET ABN	UG-SERVICE
36609164	GRET	SVC	7/22/2020	1959	RET ABN	UG-SERVICE
41411052	GRET	SVC	4/2/2024	1959	RET ABN	UG-SERVICE
41560331	GRET	SVC	6/10/2024	1959	RET ABN	UG-SERVICE
38575530	GRET	SVC	6/7/2021	1959	RET ABN	UG-SERVICE
41146287	GRET	SVC	1/9/2023	1959	RET ABN	UG-SERVICE
40371078	GRET	SVC	7/6/2022	1959	RET ABN	UG-SERVICE
36121811	GRET	SVC	10/14/2020	1959	RET ABN	UG-SERVICE
40546486	GRET	SVC	8/17/2022	1959	RET ABN	UG-SERVICE
41185868	GRET	SVC	1/20/2023	1959	RET ABN	UG-SERVICE
43469668	GRET	SVC	8/21/2024	1959	RET ABN	UG-SERVICE
39169178	GRET	SVC	9/20/2021	1959	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41085611	GRET	SVC	1/13/2023	1959	RET ABN	UG-SERVICE
42219986	GRET	SVC	10/20/2023	1959	RET ABN	UG-SERVICE
37985467	GRET	SVC	1/5/2021	1959	RET ABN	UG-SERVICE
38731096	GRET	SVC	5/24/2021	1959	RET ABN	UG-SERVICE
40561334	GRET	SVC	8/21/2022	1959	RET ABN	UG-SERVICE
36101523	GRET	SVC	4/24/2020	1959	RET ABN	UG-SERVICE
43245052	GRET	SVC	9/11/2024	1959	RET ABN	UG-SERVICE
37033025	GRET	SVC	10/6/2020	1959	RET ABN	UG-SERVICE
38503996	GRET	SVC	4/1/2021	1959	RET ABN	UG-SERVICE
42493055	GRET	SVC	12/18/2023	1959	RET ABN	UG-SERVICE
36120279	GRET	SVC	10/30/2020	1959	RET ABN	UG-SERVICE
36109951	GRET	SVC	4/22/2020	1959	RET ABN	UG-SERVICE
35926327	GRET	SVC	1/20/2020	1959	RET ABN	UG-SERVICE
40500730	GRET	SVC	8/25/2022	1959	RET ABN	UG-SERVICE
40659494	GRET	SVC	9/7/2022	1959	RET ABN	UG-SERVICE
39814853	GRET	SVC	3/7/2022	1959	RET ABN	UG-SERVICE
43775657	GRET	SVC	10/29/2024	1959	RET ABN	UG-SERVICE
38033758	GRET	SVC	1/22/2021	1959	RET ABN	UG-SERVICE
36102665	GRET	SVC	3/9/2020	1960	RET ABN	UG-SERVICE
41407614	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
41035823	GRET	SVC	12/8/2022	1960	RET ABN	UG-SERVICE
36342646	GRET	SVC	5/6/2020	1960	RET ABN	UG-SERVICE
41411769	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
39609135	GRET	SVC	4/26/2021	1960	RET ABN	UG-SERVICE
41411297	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
41529304	GRET	SVC	4/17/2023	1960	RET ABN	UG-SERVICE
40425796	GRET	SVC	7/15/2022	1960	RET ABN	UG-SERVICE
39424062	GRET	SVC	6/27/2022	1960	RET ABN	UG-SERVICE
41462844	GRET	SVC	4/17/2023	1960	RET ABN	UG-SERVICE
36241471	GRET	SVC	4/30/2020	1960	RET ABN	UG-SERVICE
42141049	GRET	SVC	8/7/2024	1960	RET ABN	UG-SERVICE
43386121	GRET	SVC	8/7/2024	1960	RET ABN	UG-SERVICE
43353802	GRET	SVC	11/6/2024	1960	RET ABN	UG-SERVICE
41407611	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
40608423	GRET	SVC	8/23/2022	1960	RET ABN	UG-SERVICE
41769886	GRET	SVC	7/14/2023	1960	RET ABN	UG-SERVICE
41411343	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
37834100	GRET	SVC	12/1/2020	1960	RET ABN	UG-SERVICE
37887893	GRET	SVC	12/7/2020	1960	RET ABN	UG-SERVICE
40139567	GRET	SVC	5/9/2022	1960	RET ABN	UG-SERVICE
41940414	GRET	SVC	7/31/2023	1960	RET ABN	UG-SERVICE
41411298	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
36342641	GRET	SVC	5/6/2020	1960	RET ABN	UG-SERVICE
39469482	GRET	SVC	11/29/2021	1960	RET ABN	UG-SERVICE
42518567	GRET	SVC	12/27/2023	1960	RET ABN	UG-SERVICE

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36342398	GRET	SVC	5/6/2020	1960	RET ABN	UG-SERVICE
43353735	GRET	SVC	11/7/2024	1960	RET ABN	UG-SERVICE
40425794	GRET	SVC	7/15/2022	1960	RET ABN	UG-SERVICE
43710834	GRET	SVC	10/16/2024	1960	RET ABN	UG-SERVICE
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39066318	GRET	SVC	9/1/2021	1960	RET ABN	UG-SERVICE
39077882	GRET	SVC	1/31/2022	1960	RET ABN	UG-SERVICE
36342644	GRET	SVC	5/6/2020	1960	RET ABN	UG-SERVICE
35997487	GRET	SVC	2/10/2020	1960	RET ABN	UG-SERVICE
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36112444	GRET	SVC	10/30/2020	1960	RET ABN	UG-SERVICE
42242910	GRET	SVC	10/12/2023	1960	RET ABN	UG-SERVICE
41407612	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
41407775	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
36769509	GRET	SVC	9/18/2020	1960	RET ABN	UG-SERVICE
42202957	GRET	SVC	10/19/2023	1960	RET ABN	UG-SERVICE
42828842	GRET	SVC	3/18/2024	1960	RET ABN	UG-SERVICE
39199772	GRET	SVC	10/11/2021	1960	RET ABN	UG-SERVICE
38033753	GRET	SVC	1/19/2021	1960	RET ABN	UG-SERVICE
34462276	GRET	SVC	1/30/2020	1960	RET ABN	UG-SERVICE
36102915	GRET	SVC	3/17/2020	1960	RET ABN	UG-SERVICE
41277651	GRET	SVC	2/13/2023	1960	RET ABN	UG-SERVICE
41051919	GRET	SVC	1/12/2023	1960	RET ABN	UG-SERVICE
41254847	GRET	SVC	2/7/2023	1960	RET ABN	UG-SERVICE
38480409	GRET	SVC	5/10/2021	1960	RET ABN	UG-SERVICE
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42021634	GRET	SVC	8/21/2023	1960	RET ABN	UG-SERVICE
38205080	GRET	SVC	3/13/2021	1960	RET ABN	UG-SERVICE
39950874	GRET	SVC	6/17/2022	1960	RET ABN	UG-SERVICE
39657141	GRET	SVC	6/28/2022	1960	RET ABN	UG-SERVICE
41185257	GRET	SVC	1/17/2023	1960	RET ABN	UG-SERVICE
40590475	GRET	SVC	8/18/2022	1960	RET ABN	UG-SERVICE
39543595	GRET	SVC	12/14/2021	1960	RET ABN	UG-SERVICE
43234865	GRET	SVC	7/8/2024	1960	RET ABN	UG-SERVICE
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39903337	GRET	SVC	3/18/2022	1960	RET ABN	UG-SERVICE
42115267	GRET	SVC	9/15/2023	1960	RET ABN	UG-SERVICE
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36124971	GRET	SVC	3/11/2020	1960	RET ABN	UG-SERVICE
40691314	GRET	SVC	9/13/2022	1960	RET ABN	UG-SERVICE
41407776	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
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42364764	GRET	SVC	11/14/2023	1960	RET ABN	UG-SERVICE
43967484	GRET	SVC	12/9/2024	1960	RET ABN	UG-SERVICE
41407767	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
41068589	GRET	SVC	12/20/2022	1960	RET ABN	UG-SERVICE
41407882	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
36983777	GRET	SVC	9/23/2020	1960	RET ABN	UG-SERVICE
41441937	GRET	SVC	9/13/2023	1960	RET ABN	UG-SERVICE
36112449	GRET	SVC	10/30/2020	1960	RET ABN	UG-SERVICE
42539919	GRET	SVC	1/5/2024	1960	RET ABN	UG-SERVICE
42028371	GRET	SVC	8/24/2023	1960	RET ABN	UG-SERVICE
41407610	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
41180788	GRET	SVC	1/4/2023	1960	RET ABN	UG-SERVICE
42862216	GRET	SVC	3/28/2024	1960	RET ABN	UG-SERVICE
38835873	GRET	SVC	8/6/2021	1960	RET ABN	UG-SERVICE
41503458	GRET	SVC	4/24/2023	1960	RET ABN	UG-SERVICE
36876164	GRET	SVC	4/19/2021	1960	RET ABN	UG-SERVICE
36363717	GRET	SVC	5/19/2020	1960	RET ABN	UG-SERVICE
36342645	GRET	SVC	5/6/2020	1960	RET ABN	UG-SERVICE
36520196	GRET	SVC	6/18/2020	1960	RET ABN	UG-SERVICE
36824153	GRET	SVC	9/14/2020	1960	RET ABN	UG-SERVICE
39657094	GRET	SVC	6/28/2022	1960	RET ABN	UG-SERVICE
39411464	GRET	SVC	11/10/2021	1960	RET ABN	UG-SERVICE
38526147	GRET	SVC	5/15/2021	1960	RET ABN	UG-SERVICE
40749570	GRET	SVC	9/30/2022	1960	RET ABN	UG-SERVICE
40933282	GRET	SVC	12/3/2022	1960	RET ABN	UG-SERVICE
36342396	GRET	SVC	5/6/2020	1960	RET ABN	UG-SERVICE
42436209	GRET	SVC	12/4/2023	1960	RET ABN	UG-SERVICE
42585048	GRET	SVC	1/23/2024	1960	RET ABN	UG-SERVICE
38849690	GRET	SVC	9/9/2021	1960	RET ABN	UG-SERVICE
39657140	GRET	SVC	6/28/2022	1960	RET ABN	UG-SERVICE
42271538	GRET	SVC	10/23/2023	1960	RET ABN	UG-SERVICE
38594661	GRET	SVC	6/24/2021	1960	RET ABN	UG-SERVICE
39727353	GRET	SVC	1/25/2022	1960	RET ABN	UG-SERVICE
36137561	GRET	SVC	4/20/2020	1960	RET ABN	UG-SERVICE
36495068	GRET	SVC	7/7/2020	1960	RET ABN	UG-SERVICE
41429979	GRET	SVC	9/13/2023	1960	RET ABN	UG-SERVICE
41411344	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
35988521	GRET	SVC	3/9/2020	1960	RET ABN	UG-SERVICE
41185580	GRET	SVC	1/20/2023	1960	RET ABN	UG-SERVICE
40751406	GRET	SVC	9/30/2022	1960	RET ABN	UG-SERVICE
37706889	GRET	SVC	11/20/2020	1960	RET ABN	UG-SERVICE
36589015	GRET	SVC	7/8/2020	1960	RET ABN	UG-SERVICE
38624477	GRET	SVC	7/29/2021	1960	RET ABN	UG-SERVICE
42969403	GRET	SVC	4/29/2024	1960	RET ABN	UG-SERVICE
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order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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43713131	GRET	SVC	10/21/2024	1960	RET ABN	UG-SERVICE
42069770	GRET	SVC	9/7/2023	1960	RET ABN	UG-SERVICE
36342640	GRET	SVC	5/6/2020	1960	RET ABN	UG-SERVICE
42888698	GRET	SVC	3/21/2024	1960	RET ABN	UG-SERVICE
40980863	GRET	SVC	11/23/2022	1960	RET ABN	UG-SERVICE
41183641	GRET	SVC	1/20/2023	1960	RET ABN	UG-SERVICE
36587660	GRET	SVC	6/9/2020	1960	RET ABN	UG-SERVICE
39230077	GRET	SVC	10/27/2021	1960	RET ABN	UG-SERVICE
38236492	GRET	SVC	3/16/2021	1960	RET ABN	UG-SERVICE
39319508	GRET	SVC	11/1/2021	1960	RET ABN	UG-SERVICE
40472862	GRET	SVC	7/26/2022	1960	RET ABN	UG-SERVICE
36068289	GRET	SVC	2/25/2020	1960	RET ABN	UG-SERVICE
43918276	GRET	SVC	12/10/2024	1960	RET ABN	UG-SERVICE
43700394	GRET	SVC	10/18/2024	1960	RET ABN	UG-SERVICE
40505994	GRET	SVC	8/5/2022	1960	RET ABN	UG-SERVICE
38881048	GRET	SVC	8/9/2021	1960	RET ABN	UG-SERVICE
37877948	GRET	SVC	11/30/2020	1960	RET ABN	UG-SERVICE
36056072	GRET	SVC	2/27/2020	1960	RET ABN	UG-SERVICE
40120512	GRET	SVC	5/3/2022	1960	RET ABN	UG-SERVICE
38064373	GRET	SVC	1/22/2021	1960	RET ABN	UG-SERVICE
36077747	GRET	SVC	3/2/2020	1960	RET ABN	UG-SERVICE
40782896	GRET	SVC	10/10/2022	1960	RET ABN	UG-SERVICE
43234773	GRET	SVC	7/11/2024	1960	RET ABN	UG-SERVICE
41243041	GRET	SVC	2/10/2023	1960	RET ABN	UG-SERVICE
36196171	GRET	SVC	6/25/2020	1960	RET ABN	UG-SERVICE
40283051	GRET	SVC	6/10/2022	1960	RET ABN	UG-SERVICE
36342397	GRET	SVC	5/6/2020	1960	RET ABN	UG-SERVICE
41441933	GRET	SVC	9/12/2023	1960	RET ABN	UG-SERVICE
41407885	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
40371452	GRET	SVC	6/29/2022	1960	RET ABN	UG-SERVICE
43445234	GRET	SVC	8/24/2024	1960	RET ABN	UG-SERVICE
32769562	GRET	SVC	7/8/2020	1960	RET ABN	UG-SERVICE
38324999	GRET	SVC	4/7/2021	1960	RET ABN	UG-SERVICE
39783713	GRET	SVC	2/11/2022	1960	RET ABN	UG-SERVICE
38575528	GRET	SVC	6/7/2021	1960	RET ABN	UG-SERVICE
41411345	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
39613737	GRET	SVC	1/5/2022	1960	RET ABN	UG-SERVICE
42670288	GRET	SVC	9/19/2024	1960	RET ABN	UG-SERVICE
41411299	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
38322497	GRET	SVC	4/3/2021	1960	RET ABN	UG-SERVICE
43184183	GRET	SVC	6/17/2024	1960	RET ABN	UG-SERVICE
41407884	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
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41279868	GRET	SVC	2/16/2023	1960	RET REM	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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40100429	GRET	SVC	5/2/2022	1960	RET ABN	UG-SERVICE
35960298	GRET	SVC	1/28/2020	1960	RET ABN	UG-SERVICE
40398607	GRET	SVC	7/15/2022	1960	RET ABN	UG-SERVICE
40265107	GRET	SVC	5/26/2022	1960	RET ABN	UG-SERVICE
37834104	GRET	SVC	12/11/2020	1960	RET ABN	UG-SERVICE
41407769	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
37529554	GRET	SVC	11/16/2020	1960	RET ABN	UG-SERVICE
41441934	GRET	SVC	9/12/2023	1960	RET ABN	UG-SERVICE
39654871	GRET	SVC	6/28/2022	1960	RET ABN	UG-SERVICE
37883994	GRET	SVC	12/8/2020	1960	RET ABN	UG-SERVICE
39379823	GRET	SVC	11/19/2021	1960	RET ABN	UG-SERVICE
42205146	GRET	SVC	10/11/2023	1960	RET ABN	UG-SERVICE
36779260	GRET	SVC	8/17/2020	1960	RET ABN	UG-SERVICE
41879337	GRET	SVC	7/17/2023	1960	RET ABN	UG-SERVICE
37891276	GRET	SVC	12/6/2020	1960	RET ABN	UG-SERVICE
41411342	GRET	SVC	4/2/2024	1960	RET ABN	UG-SERVICE
42299476	GRET	SVC	11/4/2023	1961	RET ABN	UG-SERVICE
40456658	GRET	SVC	7/20/2022	1961	RET ABN	UG-SERVICE
42548670	GRET	SVC	1/5/2024	1961	RET ABN	UG-SERVICE
38415912	GRET	SVC	4/27/2021	1961	RET ABN	UG-SERVICE
39618730	GRET	SVC	1/8/2022	1961	RET ABN	UG-SERVICE
36671619	GRET	SVC	8/21/2020	1961	RET ABN	UG-SERVICE
40230311	GRET	SVC	5/31/2022	1961	RET ABN	UG-SERVICE
37843799	GRET	SVC	11/30/2020	1961	RET ABN	UG-SERVICE
36120496	GRET	SVC	11/5/2020	1961	RET ABN	UG-SERVICE
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43918919	GRET	SVC	12/13/2024	1961	RET ABN	UG-SERVICE
39705919	GRET	SVC	1/18/2022	1961	RET ABN	UG-SERVICE
35960291	GRET	SVC	1/30/2020	1961	RET ABN	UG-SERVICE
40492793	GRET	SVC	7/23/2022	1961	RET ABN	UG-SERVICE
38125275	GRET	SVC	2/18/2021	1961	RET ABN	UG-SERVICE
40500736	GRET	SVC	8/31/2022	1961	RET ABN	UG-SERVICE
40634921	GRET	SVC	9/1/2022	1961	RET ABN	UG-SERVICE
37974006	GRET	SVC	12/23/2020	1961	RET ABN	UG-SERVICE
42185807	GRET	SVC	10/3/2023	1961	RET ABN	UG-SERVICE
43353732	GRET	SVC	11/6/2024	1961	RET ABN	UG-SERVICE
40216360	GRET	SVC	6/13/2022	1961	RET ABN	UG-SERVICE
42007332	GRET	SVC	8/15/2023	1961	RET ABN	UG-SERVICE
36469854	GRET	SVC	7/27/2020	1961	RET ABN	UG-SERVICE
38742158	GRET	SVC	7/12/2021	1961	RET ABN	UG-SERVICE
36893417	GRET	SVC	9/3/2020	1961	RET ABN	UG-SERVICE
37973881	GRET	SVC	1/5/2021	1961	RET ABN	UG-SERVICE
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order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38561615	GRET	SVC	4/19/2021	1961	RET ABN	UG-SERVICE
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38142517	GRET	SVC	2/10/2021	1961	RET ABN	UG-SERVICE
40353047	GRET	SVC	6/28/2022	1961	RET ABN	UG-SERVICE
35926372	GRET	SVC	2/13/2020	1961	RET ABN	UG-SERVICE
36977722	GRET	SVC	9/22/2020	1961	RET ABN	UG-SERVICE
40231367	GRET	SVC	6/15/2022	1961	RET ABN	UG-SERVICE
40612130	GRET	SVC	10/27/2022	1961	RET ABN	UG-SERVICE
41119588	GRET	SVC	1/6/2023	1961	RET ABN	UG-SERVICE
40330300	GRET	SVC	6/21/2022	1961	RET ABN	UG-SERVICE
42410988	GRET	SVC	11/27/2023	1961	RET ABN	UG-SERVICE
39680508	GRET	SVC	1/10/2022	1961	RET ABN	UG-SERVICE
42332980	GRET	SVC	11/3/2023	1961	RET ABN	UG-SERVICE
36164486	GRET	SVC	3/23/2020	1961	RET ABN	UG-SERVICE
41660045	GRET	SVC	5/22/2023	1961	RET ABN	UG-SERVICE
42024678	GRET	SVC	8/22/2023	1961	RET ABN	UG-SERVICE
39994343	GRET	SVC	4/19/2022	1961	RET ABN	UG-SERVICE
41411599	GRET	SVC	4/2/2024	1961	RET ABN	UG-SERVICE
43468927	GRET	SVC	8/26/2024	1961	RET ABN	UG-SERVICE
42284251	GRET	SVC	10/23/2023	1961	RET ABN	UG-SERVICE
35855538	GRET	SVC	1/7/2020	1961	RET ABN	UG-SERVICE
38187547	GRET	SVC	3/2/2021	1961	RET ABN	UG-SERVICE
40727789	GRET	SVC	10/25/2022	1961	RET ABN	UG-SERVICE
38940899	GRET	SVC	8/16/2021	1961	RET ABN	UG-SERVICE
42687136	GRET	SVC	2/13/2024	1961	RET ABN	UG-SERVICE
43511838	GRET	SVC	9/4/2024	1961	RET ABN	UG-SERVICE
35856107	GRET	SVC	1/6/2020	1961	RET ABN	UG-SERVICE
39328380	GRET	SVC	10/18/2021	1961	RET ABN	UG-SERVICE
40645368	GRET	SVC	9/1/2022	1961	RET ABN	UG-SERVICE
39463485	GRET	SVC	11/26/2021	1961	RET ABN	UG-SERVICE
40500727	GRET	SVC	8/20/2022	1961	RET ABN	UG-SERVICE
43058302	GRET	SVC	5/14/2024	1961	RET ABN	UG-SERVICE
39209627	GRET	SVC	9/28/2021	1961	RET ABN	UG-SERVICE
41436801	GRET	SVC	3/30/2023	1961	RET ABN	UG-SERVICE
43290640	GRET	SVC	7/15/2024	1961	RET ABN	UG-SERVICE
42809628	GRET	SVC	3/11/2024	1961	RET ABN	UG-SERVICE
42137713	GRET	SVC	9/21/2023	1961	RET ABN	UG-SERVICE
35862608	GRET	SVC	1/7/2020	1961	RET ABN	UG-SERVICE
43056751	GRET	SVC	5/14/2024	1961	RET ABN	UG-SERVICE
39997913	GRET	SVC	4/18/2022	1961	RET ABN	UG-SERVICE
37925865	GRET	SVC	12/18/2020	1961	RET ABN	UG-SERVICE
36343658	GRET	SVC	5/18/2020	1961	RET ABN	UG-SERVICE
35990782	GRET	SVC	2/8/2020	1961	RET ABN	UG-SERVICE
37955054	GRET	SVC	1/26/2021	1961	RET ABN	UG-SERVICE

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42956485	GRET	SVC	4/24/2024	1961	RET ABN	UG-SERVICE
43237197	GRET	SVC	7/3/2024	1961	RET ABN	UG-SERVICE
42549369	GRET	SVC	1/4/2024	1961	RET ABN	UG-SERVICE
36210724	GRET	SVC	5/7/2020	1961	RET ABN	UG-SERVICE
41320418	GRET	SVC	3/1/2023	1961	RET ABN	UG-SERVICE
43010772	GRET	SVC	5/9/2024	1961	RET ABN	UG-SERVICE
37048341	GRET	SVC	10/26/2020	1961	RET ABN	UG-SERVICE
42506319	GRET	SVC	1/11/2024	1961	RET ABN	UG-SERVICE
40359852	GRET	SVC	7/1/2022	1961	RET ABN	UG-SERVICE
39613400	GRET	SVC	12/28/2021	1961	RET ABN	UG-SERVICE
35963463	GRET	SVC	1/23/2020	1961	RET ABN	UG-SERVICE
36428510	GRET	SVC	6/29/2020	1961	RET ABN	UG-SERVICE
40561485	GRET	SVC	8/13/2022	1961	RET ABN	UG-SERVICE
42908244	GRET	SVC	4/13/2024	1961	RET ABN	UG-SERVICE
43480938	GRET	SVC	10/25/2024	1961	RET ABN	UG-SERVICE
41411641	GRET	SVC	4/2/2024	1961	RET ABN	UG-SERVICE
42896545	GRET	SVC	4/5/2024	1961	RET ABN	UG-SERVICE
43486866	GRET	SVC	8/26/2024	1961	RET ABN	UG-SERVICE
38803009	GRET	SVC	6/12/2021	1961	RET ABN	UG-SERVICE
39863174	GRET	SVC	3/9/2022	1961	RET ABN	UG-SERVICE
42169433	GRET	SVC	10/2/2023	1961	RET ABN	UG-SERVICE
36102271	GRET	SVC	4/23/2020	1961	RET ABN	UG-SERVICE
40512943	GRET	SVC	8/17/2022	1961	RET ABN	UG-SERVICE
36433443	GRET	SVC	6/12/2020	1961	RET ABN	UG-SERVICE
43607619	GRET	SVC	10/8/2024	1961	RET ABN	UG-SERVICE
38239128	GRET	SVC	3/15/2021	1961	RET ABN	UG-SERVICE
36947759	GRET	SVC	9/15/2020	1961	RET ABN	UG-SERVICE
43235511	GRET	SVC	7/2/2024	1961	RET ABN	UG-SERVICE
42865263	GRET	SVC	4/11/2024	1961	RET ABN	UG-SERVICE
37081391	GRET	SVC	10/15/2020	1961	RET ABN	UG-SERVICE
38388082	GRET	SVC	4/20/2021	1961	RET ABN	UG-SERVICE
36019872	GRET	SVC	2/14/2020	1961	RET ABN	UG-SERVICE
40667985	GRET	SVC	8/30/2022	1961	RET ABN	UG-SERVICE
35960591	GRET	SVC	2/3/2020	1961	RET ABN	UG-SERVICE
37039874	GRET	SVC	11/6/2020	1961	RET ABN	UG-SERVICE
39759217	GRET	SVC	2/8/2022	1961	RET ABN	UG-SERVICE
41003931	GRET	SVC	11/28/2022	1961	RET ABN	UG-SERVICE
38624151	GRET	SVC	6/15/2021	1961	RET ABN	UG-SERVICE
42680515	GRET	SVC	2/12/2024	1961	RET ABN	UG-SERVICE
43930848	GRET	SVC	12/10/2024	1961	RET ABN	UG-SERVICE
36833518	GRET	SVC	9/2/2020	1961	RET ABN	UG-SERVICE
40463854	GRET	SVC	8/25/2022	1961	RET ABN	UG-SERVICE
36712387	GRET	SVC	8/12/2020	1961	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36996912	GRET	SVC	9/28/2020	1961	RET ABN	UG-SERVICE
43870606	GRET	SVC	11/23/2024	1961	RET ABN	UG-SERVICE
41287274	GRET	SVC	2/24/2023	1961	RET ABN	UG-SERVICE
38276274	GRET	SVC	3/25/2021	1961	RET ABN	UG-SERVICE
40416539	GRET	SVC	7/14/2022	1961	RET ABN	UG-SERVICE
36802711	GRET	SVC	9/21/2020	1961	RET ABN	UG-SERVICE
40644179	GRET	SVC	9/14/2022	1961	RET ABN	UG-SERVICE
42595957	GRET	SVC	1/25/2024	1961	RET ABN	UG-SERVICE
42177090	GRET	SVC	10/2/2023	1961	RET ABN	UG-SERVICE
42590284	GRET	SVC	1/29/2024	1961	RET ABN	UG-SERVICE
42246019	GRET	SVC	10/19/2023	1961	RET ABN	UG-SERVICE
42140976	GRET	SVC	10/5/2023	1961	RET ABN	UG-SERVICE
35960288	GRET	SVC	1/28/2020	1961	RET ABN	UG-SERVICE
40670805	GRET	SVC	9/15/2022	1961	RET ABN	UG-SERVICE
43304929	GRET	SVC	7/15/2024	1961	RET ABN	UG-SERVICE
42380961	GRET	SVC	12/2/2023	1961	RET ABN	UG-SERVICE
38595490	GRET	SVC	6/7/2021	1961	RET ABN	UG-SERVICE
39741942	GRET	SVC	1/31/2022	1961	RET ABN	UG-SERVICE
40612444	GRET	SVC	10/27/2022	1961	RET ABN	UG-SERVICE
36120497	GRET	SVC	11/5/2020	1961	RET ABN	UG-SERVICE
41063457	GRET	SVC	12/15/2022	1961	RET ABN	UG-SERVICE
41634521	GRET	SVC	5/16/2023	1961	RET ABN	UG-SERVICE
43445180	GRET	SVC	8/13/2024	1961	RET ABN	UG-SERVICE
37841630	GRET	SVC	11/30/2020	1961	RET ABN	UG-SERVICE
40701267	GRET	SVC	9/15/2022	1961	RET ABN	UG-SERVICE
42855076	GRET	SVC	3/21/2024	1961	RET ABN	UG-SERVICE
36587825	GRET	SVC	7/23/2020	1961	RET ABN	UG-SERVICE
41577209	GRET	SVC	5/1/2023	1961	RET ABN	UG-SERVICE
38934636	GRET	SVC	8/23/2021	1961	RET ABN	UG-SERVICE
38314468	GRET	SVC	4/6/2021	1961	RET ABN	UG-SERVICE
40498213	GRET	SVC	7/26/2022	1961	RET ABN	UG-SERVICE
43710050	GRET	SVC	10/16/2024	1961	RET ABN	UG-SERVICE
36137410	GRET	SVC	4/21/2020	1961	RET ABN	UG-SERVICE
43036780	GRET	SVC	5/9/2024	1961	RET ABN	UG-SERVICE
42860518	GRET	SVC	3/26/2024	1961	RET ABN	UG-SERVICE
39756199	GRET	SVC	2/10/2022	1961	RET ABN	UG-SERVICE
42409246	GRET	SVC	11/27/2023	1961	RET ABN	UG-SERVICE
43445182	GRET	SVC	8/16/2024	1961	RET ABN	UG-SERVICE
40224351	GRET	SVC	5/29/2022	1961	RET ABN	UG-SERVICE
42651562	GRET	SVC	2/1/2024	1961	RET ABN	UG-SERVICE
42166122	GRET	SVC	9/19/2023	1961	RET ABN	UG-SERVICE
38681627	GRET	SVC	6/28/2021	1961	RET ABN	UG-SERVICE
41436559	GRET	SVC	3/30/2023	1961	RET ABN	UG-SERVICE
36988225	GRET	SVC	9/24/2020	1961	RET ABN	UG-SERVICE
38441546	GRET	SVC	1/3/2022	1961	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42248566	GRET	SVC	10/18/2023	1961	RET ABN	UG-SERVICE
40316642	GRET	SVC	6/21/2022	1962	RET ABN	UG-SERVICE
43793521	GRET	SVC	11/6/2024	1962	RET ABN	UG-SERVICE
38441445	GRET	SVC	1/3/2022	1962	RET ABN	UG-SERVICE
42507088	GRET	SVC	1/25/2024	1962	RET ABN	UG-SERVICE
38607202	GRET	SVC	6/11/2021	1962	RET ABN	UG-SERVICE
42138327	GRET	SVC	9/25/2023	1962	RET ABN	UG-SERVICE
40162115	GRET	SVC	5/16/2022	1962	RET ABN	UG-SERVICE
36137880	GRET	SVC	4/20/2020	1962	RET ABN	UG-SERVICE
41775612	GRET	SVC	6/26/2023	1962	RET ABN	UG-SERVICE
40246933	GRET	SVC	6/1/2022	1962	RET ABN	UG-SERVICE
37900933	GRET	SVC	12/11/2020	1962	RET ABN	UG-SERVICE
40514002	GRET	SVC	8/5/2022	1962	RET ABN	UG-SERVICE
36122362	GRET	SVC	10/30/2020	1962	RET ABN	UG-SERVICE
42491328	GRET	SVC	12/19/2023	1962	RET ABN	UG-SERVICE
36419786	GRET	SVC	6/19/2020	1962	RET ABN	UG-SERVICE
38818719	GRET	SVC	7/21/2021	1962	RET ABN	UG-SERVICE
37023787	GRET	SVC	1/6/2021	1962	RET ABN	UG-SERVICE
41803574	GRET	SVC	6/30/2023	1962	RET ABN	UG-SERVICE
38122575	GRET	SVC	2/20/2021	1962	RET ABN	UG-SERVICE
38943041	GRET	SVC	8/17/2021	1962	RET ABN	UG-SERVICE
37948944	GRET	SVC	3/31/2021	1962	RET ABN	UG-SERVICE
43221438	GRET	SVC	7/3/2024	1962	RET ABN	UG-SERVICE
41106287	GRET	SVC	2/1/2023	1962	RET ABN	UG-SERVICE
42561425	GRET	SVC	1/11/2024	1962	RET ABN	UG-SERVICE
41614906	GRET	SVC	5/10/2023	1962	RET ABN	UG-SERVICE
40561481	GRET	SVC	8/18/2022	1962	RET ABN	UG-SERVICE
40545926	GRET	SVC	8/10/2022	1962	RET ABN	UG-SERVICE
43623488	GRET	SVC	12/4/2024	1962	RET ABN	UG-SERVICE
42043602	GRET	SVC	9/6/2023	1962	RET ABN	UG-SERVICE
36590133	GRET	SVC	9/30/2020	1962	RET ABN	UG-SERVICE
43448067	GRET	SVC	8/15/2024	1962	RET ABN	UG-SERVICE
40181796	GRET	SVC	5/16/2022	1962	RET ABN	UG-SERVICE
39445868	GRET	SVC	12/6/2021	1962	RET ABN	UG-SERVICE
42496456	GRET	SVC	12/21/2023	1962	RET ABN	UG-SERVICE
41018463	GRET	SVC	12/7/2022	1962	RET ABN	UG-SERVICE
40216739	GRET	SVC	6/27/2022	1962	RET ABN	UG-SERVICE
40472860	GRET	SVC	7/26/2022	1962	RET ABN	UG-SERVICE
37045167	GRET	SVC	10/7/2020	1962	RET ABN	UG-SERVICE
36240446	GRET	SVC	5/1/2020	1962	RET ABN	UG-SERVICE
41179267	GRET	SVC	1/18/2023	1962	RET ABN	UG-SERVICE
36141882	GRET	SVC	3/16/2020	1962	RET ABN	UG-SERVICE
40495499	GRET	SVC	8/14/2022	1962	RET ABN	UG-SERVICE
38531968	GRET	SVC	6/25/2021	1962	RET ABN	UG-SERVICE
41114164	GRET	SVC	12/30/2022	1962	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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36091006	GRET	SVC	4/30/2020	1962	RET ABN	UG-SERVICE
39448053	GRET	SVC	11/22/2021	1962	RET ABN	UG-SERVICE
41888789	GRET	SVC	7/19/2023	1962	RET ABN	UG-SERVICE
36760768	GRET	SVC	8/12/2020	1962	RET ABN	UG-SERVICE
41338340	GRET	SVC	3/20/2023	1962	RET ABN	UG-SERVICE
39152932	GRET	SVC	9/20/2021	1962	RET ABN	UG-SERVICE
36658261	GRET	SVC	7/20/2020	1962	RET ABN	UG-SERVICE
43975758	GRET	SVC	12/30/2024	1962	RET ABN	UG-SERVICE
38043536	GRET	SVC	1/21/2021	1962	RET ABN	UG-SERVICE
37025413	GRET	SVC	11/13/2020	1962	RET ABN	UG-SERVICE
41106293	GRET	SVC	1/4/2023	1962	RET ABN	UG-SERVICE
36103124	GRET	SVC	3/9/2020	1962	RET ABN	UG-SERVICE
43794870	GRET	SVC	11/12/2024	1962	RET ABN	UG-SERVICE
41573261	GRET	SVC	4/26/2023	1962	RET ABN	UG-SERVICE
40488535	GRET	SVC	7/27/2022	1962	RET ABN	UG-SERVICE
35985632	GRET	SVC	2/3/2020	1962	RET ABN	UG-SERVICE
41590197	GRET	SVC	4/19/2023	1962	RET ABN	UG-SERVICE
43957617	GRET	SVC	12/18/2024	1962	RET ABN	UG-SERVICE
44025728	GRET	SVC	12/18/2024	1962	RET ABN	UG-SERVICE
43108406	GRET	SVC	5/17/2024	1962	RET ABN	UG-SERVICE
42554645	GRET	SVC	1/10/2024	1962	RET ABN	UG-SERVICE
36540578	GRET	SVC	5/21/2020	1962	RET ABN	UG-SERVICE
36137856	GRET	SVC	4/20/2020	1962	RET ABN	UG-SERVICE
36106423	GRET	SVC	10/30/2020	1962	RET ABN	UG-SERVICE
37103006	GRET	SVC	10/23/2020	1962	RET ABN	UG-SERVICE
38097502	GRET	SVC	9/2/2021	1962	RET ABN	UG-SERVICE
36138115	GRET	SVC	4/21/2020	1962	RET ABN	UG-SERVICE
40924917	GRET	SVC	12/9/2022	1962	RET ABN	UG-SERVICE
38659705	GRET	SVC	6/22/2021	1962	RET ABN	UG-SERVICE
40545905	GRET	SVC	8/10/2022	1962	RET ABN	UG-SERVICE
43620583	GRET	SVC	9/19/2024	1962	RET ABN	UG-SERVICE
42180663	GRET	SVC	9/27/2023	1962	RET ABN	UG-SERVICE
36608884	GRET	SVC	7/13/2020	1962	RET ABN	UG-SERVICE
39459830	GRET	SVC	11/24/2021	1962	RET ABN	UG-SERVICE
37877296	GRET	SVC	12/7/2020	1962	RET ABN	UG-SERVICE
43763661	GRET	SVC	11/1/2024	1962	RET ABN	UG-SERVICE
42278781	GRET	SVC	11/1/2023	1962	RET ABN	UG-SERVICE
36818385	GRET	SVC	11/3/2020	1962	RET ABN	UG-SERVICE
38595701	GRET	SVC	6/9/2021	1962	RET ABN	UG-SERVICE
41429966	GRET	SVC	9/19/2023	1962	RET ABN	UG-SERVICE
41478971	GRET	SVC	4/14/2023	1962	RET ABN	UG-SERVICE
38211695	GRET	SVC	3/9/2021	1962	RET ABN	UG-SERVICE
40963269	GRET	SVC	12/20/2022	1962	RET ABN	UG-SERVICE
38571056	GRET	SVC	6/11/2021	1962	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38033745	GRET	SVC	1/22/2021	1962	RET ABN	UG-SERVICE
43656240	GRET	SVC	10/19/2024	1962	RET ABN	UG-SERVICE
41210969	GRET	SVC	12/11/2023	1962	RET ABN	UG-SERVICE
41065859	GRET	SVC	12/15/2022	1962	RET ABN	UG-SERVICE
42982497	GRET	SVC	4/29/2024	1962	RET ABN	UG-SERVICE
40217061	GRET	SVC	5/24/2022	1962	RET ABN	UG-SERVICE
39766939	GRET	SVC	2/8/2022	1962	RET ABN	UG-SERVICE
38396451	GRET	SVC	4/22/2021	1962	RET ABN	UG-SERVICE
37045188	GRET	SVC	10/9/2020	1962	RET ABN	UG-SERVICE
41330546	GRET	SVC	3/1/2023	1962	RET ABN	UG-SERVICE
38097223	GRET	SVC	9/2/2021	1962	RET ABN	UG-SERVICE
36787049	GRET	SVC	8/17/2020	1962	RET ABN	UG-SERVICE
41380228	GRET	SVC	3/14/2023	1962	RET ABN	UG-SERVICE
38185324	GRET	SVC	3/4/2021	1962	RET ABN	UG-SERVICE
43474116	GRET	SVC	8/22/2024	1962	RET ABN	UG-SERVICE
36093024	GRET	SVC	4/27/2020	1962	RET ABN	UG-SERVICE
39254233	GRET	SVC	10/8/2021	1962	RET ABN	UG-SERVICE
41105420	GRET	SVC	1/21/2023	1962	RET ABN	UG-SERVICE
36729952	GRET	SVC	8/4/2020	1962	RET ABN	UG-SERVICE
38976089	GRET	SVC	8/22/2021	1962	RET ABN	UG-SERVICE
37322812	GRET	SVC	11/10/2020	1962	RET ABN	UG-SERVICE
43596820	GRET	SVC	10/1/2024	1962	RET ABN	UG-SERVICE
40225209	GRET	SVC	6/21/2022	1962	RET ABN	UG-SERVICE
37096383	GRET	SVC	10/20/2020	1962	RET ABN	UG-SERVICE
41052707	GRET	SVC	1/12/2023	1962	RET ABN	UG-SERVICE
39252661	GRET	SVC	6/12/2021	1962	RET ABN	UG-SERVICE
39916059	GRET	SVC	4/25/2022	1962	RET ABN	UG-SERVICE
43245088	GRET	SVC	9/11/2024	1962	RET ABN	UG-SERVICE
41767405	GRET	SVC	6/20/2023	1962	RET ABN	UG-SERVICE
42943003	GRET	SVC	4/16/2024	1962	RET ABN	UG-SERVICE
41236473	GRET	SVC	2/7/2023	1962	RET ABN	UG-SERVICE
42428939	GRET	SVC	11/30/2023	1962	RET ABN	UG-SERVICE
40522780	GRET	SVC	8/5/2022	1962	RET ABN	UG-SERVICE
43092112	GRET	SVC	5/23/2024	1962	RET ABN	UG-SERVICE
36142485	GRET	SVC	3/18/2020	1962	RET ABN	UG-SERVICE
37883992	GRET	SVC	12/9/2020	1962	RET ABN	UG-SERVICE
41114177	GRET	SVC	12/30/2022	1962	RET ABN	UG-SERVICE
42137793	GRET	SVC	9/25/2023	1962	RET ABN	UG-SERVICE
36809613	GRET	SVC	8/23/2020	1962	RET ABN	UG-SERVICE
39064575	GRET	SVC	9/2/2021	1962	RET ABN	UG-SERVICE
36138116	GRET	SVC	4/20/2020	1962	RET ABN	UG-SERVICE
41083868	GRET	SVC	12/20/2022	1962	RET ABN	UG-SERVICE
38741233	GRET	SVC	7/12/2021	1962	RET ABN	UG-SERVICE
42465584	GRET	SVC	12/13/2023	1962	RET ABN	UG-SERVICE
38735429	GRET	SVC	8/24/2021	1962	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42344688	GRET	SVC	11/7/2023	1962	RET ABN	UG-SERVICE
37940639	GRET	SVC	1/5/2021	1962	RET ABN	UG-SERVICE
41316690	GRET	SVC	2/27/2023	1963	RET ABN	UG-SERVICE
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36045936	GRET	SVC	2/21/2020	1963	RET ABN	UG-SERVICE
39385318	GRET	SVC	3/28/2022	1963	RET ABN	UG-SERVICE
40912633	GRET	SVC	11/8/2022	1963	RET ABN	UG-SERVICE
42418419	GRET	SVC	11/27/2023	1963	RET ABN	UG-SERVICE
37593076	GRET	SVC	1/21/2021	1963	RET ABN	UG-SERVICE
42956869	GRET	SVC	9/19/2024	1963	RET ABN	UG-SERVICE
42834156	GRET	SVC	7/23/2024	1963	RET ABN	UG-SERVICE
40009604	GRET	SVC	4/19/2022	1963	RET ABN	UG-SERVICE
42681364	GRET	SVC	8/1/2024	1963	RET ABN	UG-SERVICE
42292950	GRET	SVC	11/1/2023	1963	RET ABN	UG-SERVICE
39925585	GRET	SVC	3/9/2022	1963	RET ABN	UG-SERVICE
41853019	GRET	SVC	7/12/2023	1963	RET ABN	UG-SERVICE
37953467	GRET	SVC	12/22/2020	1963	RET ABN	UG-SERVICE
42204578	GRET	SVC	10/9/2023	1963	RET ABN	UG-SERVICE
43524154	GRET	SVC	9/12/2024	1963	RET ABN	UG-SERVICE
42748898	GRET	SVC	2/22/2024	1963	RET ABN	UG-SERVICE
43353625	GRET	SVC	11/4/2024	1963	RET ABN	UG-SERVICE
43625813	GRET	SVC	9/30/2024	1963	RET ABN	UG-SERVICE
38441295	GRET	SVC	1/3/2022	1963	RET ABN	UG-SERVICE
43675965	GRET	SVC	10/10/2024	1963	RET ABN	UG-SERVICE
42333907	GRET	SVC	11/10/2023	1963	RET ABN	UG-SERVICE
41088832	GRET	SVC	1/6/2023	1963	RET ABN	UG-SERVICE
42196659	GRET	SVC	10/9/2023	1963	RET ABN	UG-SERVICE
43327968	GRET	SVC	7/15/2024	1963	RET ABN	UG-SERVICE
36101971	GRET	SVC	4/23/2020	1963	RET ABN	UG-SERVICE
41411276	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
36918200	GRET	SVC	8/17/2020	1963	RET ABN	UG-SERVICE
38172940	GRET	SVC	2/26/2021	1963	RET ABN	UG-SERVICE
42487543	GRET	SVC	11/9/2023	1963	RET ABN	UG-SERVICE
38312531	GRET	SVC	10/5/2021	1963	RET ABN	UG-SERVICE
40883584	GRET	SVC	11/4/2022	1963	RET ABN	UG-SERVICE
40898581	GRET	SVC	11/2/2022	1963	RET ABN	UG-SERVICE
42938326	GRET	SVC	4/16/2024	1963	RET ABN	UG-SERVICE
41408968	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
41085606	GRET	SVC	12/21/2022	1963	RET ABN	UG-SERVICE
41079133	GRET	SVC	12/20/2022	1963	RET ABN	UG-SERVICE
40608420	GRET	SVC	8/23/2022	1963	RET ABN	UG-SERVICE
41075030	GRET	SVC	12/29/2022	1963	RET ABN	UG-SERVICE
40443479	GRET	SVC	7/18/2022	1963	RET ABN	UG-SERVICE
40811065	GRET	SVC	10/13/2022	1963	RET ABN	UG-SERVICE
41075023	GRET	SVC	12/20/2022	1963	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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40497359	GRET	SVC	7/26/2022	1963	RET ABN	UG-SERVICE
41610030	GRET	SVC	5/8/2023	1963	RET ABN	UG-SERVICE
41298235	GRET	SVC	2/24/2023	1963	RET ABN	UG-SERVICE
41180405	GRET	SVC	1/25/2023	1963	RET ABN	UG-SERVICE
42653894	GRET	SVC	1/29/2024	1963	RET ABN	UG-SERVICE
38736867	GRET	SVC	7/12/2021	1963	RET ABN	UG-SERVICE
38699828	GRET	SVC	6/29/2021	1963	RET ABN	UG-SERVICE
41027616	GRET	SVC	12/14/2022	1963	RET ABN	UG-SERVICE
39879060	GRET	SVC	3/14/2022	1963	RET ABN	UG-SERVICE
43480991	GRET	SVC	11/20/2024	1963	RET ABN	UG-SERVICE
36751503	GRET	SVC	8/12/2020	1963	RET ABN	UG-SERVICE
36047648	GRET	SVC	2/21/2020	1963	RET ABN	UG-SERVICE
40607679	GRET	SVC	8/23/2022	1963	RET ABN	UG-SERVICE
41179264	GRET	SVC	1/23/2023	1963	RET ABN	UG-SERVICE
40315630	GRET	SVC	6/13/2022	1963	RET ABN	UG-SERVICE
36056425	GRET	SVC	2/24/2020	1963	RET ABN	UG-SERVICE
37932659	GRET	SVC	12/16/2020	1963	RET ABN	UG-SERVICE
43627921	GRET	SVC	9/28/2024	1963	RET ABN	UG-SERVICE
36254937	GRET	SVC	3/7/2020	1963	RET ABN	UG-SERVICE
32667123	GRET	SVC	11/1/2020	1963	RET ABN	UG-SERVICE
35996899	GRET	SVC	2/10/2020	1963	RET ABN	UG-SERVICE
37097501	GRET	SVC	12/9/2020	1963	RET ABN	UG-SERVICE
38579872	GRET	SVC	9/28/2021	1963	RET ABN	UG-SERVICE
43063031	GRET	SVC	5/14/2024	1963	RET ABN	UG-SERVICE
41408006	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
41273853	GRET	SVC	2/15/2023	1963	RET ABN	UG-SERVICE
42565052	GRET	SVC	1/10/2024	1963	RET ABN	UG-SERVICE
41593695	GRET	SVC	5/31/2023	1963	RET ABN	UG-SERVICE
37045853	GRET	SVC	10/9/2020	1963	RET ABN	UG-SERVICE
38441299	GRET	SVC	1/3/2022	1963	RET ABN	UG-SERVICE
41411430	GRET	SVC	11/2/2023	1963	RET ABN	UG-SERVICE
42674645	GRET	SVC	2/6/2024	1963	RET ABN	UG-SERVICE
41414945	GRET	SVC	3/21/2023	1963	RET ABN	UG-SERVICE
37025410	GRET	SVC	10/16/2020	1963	RET ABN	UG-SERVICE
40895494	GRET	SVC	10/28/2022	1963	RET ABN	UG-SERVICE
43462069	GRET	SVC	10/7/2024	1963	RET ABN	UG-SERVICE
43100268	GRET	SVC	6/3/2024	1963	RET ABN	UG-SERVICE
41015447	GRET	SVC	12/16/2022	1963	RET ABN	UG-SERVICE
41330542	GRET	SVC	3/3/2023	1963	RET ABN	UG-SERVICE
37387646	GRET	SVC	11/9/2020	1963	RET ABN	UG-SERVICE
41194798	GRET	SVC	1/23/2023	1963	RET ABN	UG-SERVICE
41241964	GRET	SVC	3/1/2023	1963	RET ABN	UG-SERVICE
38726593	GRET	SVC	7/12/2021	1963	RET ABN	UG-SERVICE
39806444	GRET	SVC	3/1/2022	1963	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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38179599	GRET	SVC	3/3/2021	1963	RET ABN	UG-SERVICE
42972889	GRET	SVC	4/22/2024	1963	RET ABN	UG-SERVICE
40488325	GRET	SVC	7/27/2022	1963	RET ABN	UG-SERVICE
41074876	GRET	SVC	12/22/2022	1963	RET ABN	UG-SERVICE
38267218	GRET	SVC	3/22/2021	1963	RET ABN	UG-SERVICE
41411224	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
41051914	GRET	SVC	1/12/2023	1963	RET ABN	UG-SERVICE
40440351	GRET	SVC	6/30/2022	1963	RET ABN	UG-SERVICE
42792743	GRET	SVC	7/2/2024	1963	RET ABN	UG-SERVICE
41069356	GRET	SVC	1/5/2023	1963	RET ABN	UG-SERVICE
41440482	GRET	SVC	3/27/2023	1963	RET ABN	UG-SERVICE
39545562	GRET	SVC	1/10/2022	1963	RET ABN	UG-SERVICE
37088508	GRET	SVC	10/20/2020	1963	RET ABN	UG-SERVICE
41052710	GRET	SVC	1/12/2023	1963	RET ABN	UG-SERVICE
36121609	GRET	SVC	10/30/2020	1963	RET ABN	UG-SERVICE
37934041	GRET	SVC	12/21/2020	1963	RET ABN	UG-SERVICE
38334678	GRET	SVC	4/7/2021	1963	RET ABN	UG-SERVICE
41969557	GRET	SVC	8/1/2024	1963	RET ABN	UG-SERVICE
38091187	GRET	SVC	2/19/2021	1963	RET ABN	UG-SERVICE
40802173	GRET	SVC	10/12/2022	1963	RET ABN	UG-SERVICE
38543965	GRET	SVC	5/25/2021	1963	RET ABN	UG-SERVICE
43189731	GRET	SVC	6/19/2024	1963	RET ABN	UG-SERVICE
41408065	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
43480990	GRET	SVC	11/20/2024	1963	RET ABN	UG-SERVICE
42833355	GRET	SVC	7/22/2024	1963	RET ABN	UG-SERVICE
42910311	GRET	SVC	6/21/2024	1963	RET ABN	UG-SERVICE
42193964	GRET	SVC	10/10/2023	1963	RET ABN	UG-SERVICE
36740597	GRET	SVC	8/5/2020	1963	RET ABN	UG-SERVICE
41408005	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
38441487	GRET	SVC	1/6/2022	1963	RET ABN	UG-SERVICE
42265960	GRET	SVC	10/26/2023	1963	RET ABN	UG-SERVICE
41411266	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
41318581	GRET	SVC	3/2/2023	1963	RET ABN	UG-SERVICE
39478139	GRET	SVC	12/3/2021	1963	RET ABN	UG-SERVICE
36685507	GRET	SVC	7/27/2020	1963	RET ABN	UG-SERVICE
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36433567	GRET	SVC	6/10/2020	1963	RET ABN	UG-SERVICE
42297558	GRET	SVC	11/1/2023	1963	RET ABN	UG-SERVICE
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41104256	GRET	SVC	1/21/2023	1963	RET ABN	UG-SERVICE
40611928	GRET	SVC	8/21/2022	1963	RET ABN	UG-SERVICE
40775287	GRET	SVC	9/26/2022	1963	RET ABN	UG-SERVICE
41410852	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
38906164	GRET	SVC	9/17/2021	1963	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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38934718	GRET	SVC	8/19/2021	1963	RET ABN	UG-SERVICE
39831656	GRET	SVC	8/3/2022	1963	RET ABN	UG-SERVICE
38593533	GRET	SVC	6/22/2021	1963	RET ABN	UG-SERVICE
43943431	GRET	SVC	12/18/2024	1963	RET ABN	UG-SERVICE
40561494	GRET	SVC	8/27/2022	1963	RET ABN	UG-SERVICE
42944585	GRET	SVC	4/9/2024	1963	RET ABN	UG-SERVICE
37088362	GRET	SVC	10/20/2020	1963	RET ABN	UG-SERVICE
37455519	GRET	SVC	11/23/2020	1963	RET ABN	UG-SERVICE
36014157	GRET	SVC	2/11/2020	1963	RET ABN	UG-SERVICE
42542521	GRET	SVC	4/30/2024	1963	RET ABN	UG-SERVICE
41411419	GRET	SVC	11/2/2023	1963	RET ABN	UG-SERVICE
36152267	GRET	SVC	3/16/2020	1963	RET ABN	UG-SERVICE
43559752	GRET	SVC	10/4/2024	1963	RET ABN	UG-SERVICE
42649991	GRET	SVC	2/1/2024	1963	RET ABN	UG-SERVICE
37387518	GRET	SVC	11/9/2020	1963	RET ABN	UG-SERVICE
41410851	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
41817666	GRET	SVC	6/29/2023	1963	RET ABN	UG-SERVICE
41411046	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
41321959	GRET	SVC	3/9/2023	1963	RET ABN	UG-SERVICE
39864036	GRET	SVC	3/9/2022	1963	RET ABN	UG-SERVICE
41946657	GRET	SVC	8/8/2023	1963	RET ABN	UG-SERVICE
41825248	GRET	SVC	7/5/2023	1963	RET ABN	UG-SERVICE
36138460	GRET	SVC	3/19/2020	1963	RET ABN	UG-SERVICE
43606797	GRET	SVC	11/15/2024	1963	RET ABN	UG-SERVICE
38861641	GRET	SVC	8/9/2021	1963	RET ABN	UG-SERVICE
40141884	GRET	SVC	5/13/2022	1963	RET ABN	UG-SERVICE
37892183	GRET	SVC	12/10/2020	1963	RET ABN	UG-SERVICE
38441298	GRET	SVC	1/6/2022	1963	RET ABN	UG-SERVICE
43886024	GRET	SVC	11/25/2024	1963	RET ABN	UG-SERVICE
42197020	GRET	SVC	10/9/2023	1963	RET ABN	UG-SERVICE
39543012	GRET	SVC	12/16/2021	1963	RET ABN	UG-SERVICE
38441289	GRET	SVC	1/6/2022	1963	RET ABN	UG-SERVICE
41408064	GRET	SVC	4/2/2024	1963	RET ABN	UG-SERVICE
40854508	GRET	SVC	10/22/2022	1963	RET ABN	UG-SERVICE
37082696	GRET	SVC	10/15/2020	1963	RET ABN	UG-SERVICE
40066513	GRET	SVC	3/31/2022	1963	RET ABN	UG-SERVICE
42056715	GRET	SVC	8/30/2023	1963	RET ABN	UG-SERVICE
37084631	GRET	SVC	10/15/2020	1963	RET ABN	UG-SERVICE
42956323	GRET	SVC	9/19/2024	1963	RET ABN	UG-SERVICE
36153320	GRET	SVC	3/19/2020	1963	RET ABN	UG-SERVICE
42314563	GRET	SVC	11/7/2023	1963	RET ABN	UG-SERVICE
36137314	GRET	SVC	4/20/2020	1963	RET ABN	UG-SERVICE
39935401	GRET	SVC	6/20/2022	1963	RET ABN	UG-SERVICE
40363435	GRET	SVC	6/28/2022	1963	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41741522	GRET	SVC	6/13/2023	1963	RET ABN	UG-SERVICE
36387252	GRET	SVC	6/1/2020	1963	RET ABN	UG-SERVICE
42681362	GRET	SVC	8/1/2024	1963	RET ABN	UG-SERVICE
40432964	GRET	SVC	7/14/2022	1963	RET ABN	UG-SERVICE
43623796	GRET	SVC	9/27/2024	1963	RET ABN	UG-SERVICE
43624005	GRET	SVC	10/1/2024	1963	RET ABN	UG-SERVICE
41052706	GRET	SVC	1/12/2023	1963	RET ABN	UG-SERVICE
43444205	GRET	SVC	8/15/2024	1963	RET ABN	UG-SERVICE
41052709	GRET	SVC	1/12/2023	1963	RET ABN	UG-SERVICE
38959418	GRET	SVC	8/17/2021	1963	RET ABN	UG-SERVICE
40723258	GRET	SVC	10/19/2022	1964	RET ABN	UG-SERVICE
40675411	GRET	SVC	9/15/2022	1964	RET ABN	UG-SERVICE
36110467	GRET	SVC	4/20/2020	1964	RET ABN	UG-SERVICE
36753394	GRET	SVC	4/7/2022	1964	RET ABN	UG-SERVICE
43086207	GRET	SVC	5/17/2024	1964	RET ABN	UG-SERVICE
36081780	GRET	SVC	3/4/2020	1964	RET ABN	UG-SERVICE
39923819	GRET	SVC	3/24/2022	1964	RET ABN	UG-SERVICE
37932977	GRET	SVC	12/17/2020	1964	RET ABN	UG-SERVICE
42833352	GRET	SVC	7/23/2024	1964	RET ABN	UG-SERVICE
38033818	GRET	SVC	1/22/2021	1964	RET ABN	UG-SERVICE
36136180	GRET	SVC	4/23/2020	1964	RET ABN	UG-SERVICE
36121614	GRET	SVC	10/12/2020	1964	RET ABN	UG-SERVICE
41318155	GRET	SVC	3/3/2023	1964	RET ABN	UG-SERVICE
36138305	GRET	SVC	4/20/2020	1964	RET ABN	UG-SERVICE
37917270	GRET	SVC	12/15/2020	1964	RET ABN	UG-SERVICE
36751246	GRET	SVC	8/19/2020	1964	RET ABN	UG-SERVICE
38232314	GRET	SVC	3/16/2021	1964	RET ABN	UG-SERVICE
32667129	GRET	SVC	9/30/2020	1964	RET ABN	UG-SERVICE
43624720	GRET	SVC	9/27/2024	1964	RET ABN	UG-SERVICE
39541262	GRET	SVC	3/9/2022	1964	RET ABN	UG-SERVICE
41079886	GRET	SVC	4/5/2024	1964	RET ABN	UG-SERVICE
39905417	GRET	SVC	1/9/2023	1964	RET ABN	UG-SERVICE
36137779	GRET	SVC	4/21/2020	1964	RET ABN	UG-SERVICE
41911378	GRET	SVC	7/28/2023	1964	RET ABN	UG-SERVICE
39955662	GRET	SVC	5/18/2022	1964	RET ABN	UG-SERVICE
38312803	GRET	SVC	4/7/2021	1964	RET ABN	UG-SERVICE
39288068	GRET	SVC	10/10/2021	1964	RET ABN	UG-SERVICE
39928987	GRET	SVC	3/22/2022	1964	RET ABN	UG-SERVICE
38489303	GRET	SVC	4/1/2021	1964	RET ABN	UG-SERVICE
42140813	GRET	SVC	9/19/2023	1964	RET ABN	UG-SERVICE
36137882	GRET	SVC	4/22/2020	1964	RET ABN	UG-SERVICE
40654853	GRET	SVC	9/7/2022	1964	RET ABN	UG-SERVICE
39950426	GRET	SVC	3/30/2022	1964	RET ABN	UG-SERVICE
41790202	GRET	SVC	6/28/2023	1964	RET ABN	UG-SERVICE
39875446	GRET	SVC	3/9/2022	1964	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42906204	GRET	SVC	4/7/2024	1964	RET ABN	UG-SERVICE
39666616	GRET	SVC	11/18/2022	1964	RET ABN	UG-SERVICE
40315825	GRET	SVC	6/20/2022	1964	RET ABN	UG-SERVICE
41904015	GRET	SVC	7/25/2023	1964	RET ABN	UG-SERVICE
38543492	GRET	SVC	10/20/2021	1964	RET ABN	UG-SERVICE
39125879	GRET	SVC	9/13/2021	1964	RET ABN	UG-SERVICE
39291302	GRET	SVC	10/13/2021	1964	RET ABN	UG-SERVICE
41411646	GRET	SVC	4/2/2024	1964	RET ABN	UG-SERVICE
39830419	GRET	SVC	8/3/2022	1964	RET ABN	UG-SERVICE
41750843	GRET	SVC	6/12/2023	1964	RET ABN	UG-SERVICE
41024535	GRET	SVC	4/4/2023	1964	RET ABN	UG-SERVICE
42620386	GRET	SVC	1/25/2024	1964	RET ABN	UG-SERVICE
39666744	GRET	SVC	11/18/2022	1964	RET ABN	UG-SERVICE
43714036	GRET	SVC	11/12/2024	1964	RET ABN	UG-SERVICE
40517068	GRET	SVC	8/6/2022	1964	RET ABN	UG-SERVICE
36321219	GRET	SVC	7/6/2020	1964	RET ABN	UG-SERVICE
40030349	GRET	SVC	4/20/2022	1964	RET ABN	UG-SERVICE
41541192	GRET	SVC	5/22/2023	1964	RET ABN	UG-SERVICE
39450179	GRET	SVC	11/22/2021	1964	RET ABN	UG-SERVICE
38400028	GRET	SVC	4/21/2021	1964	RET ABN	UG-SERVICE
39804198	GRET	SVC	2/15/2022	1964	RET ABN	UG-SERVICE
38033750	GRET	SVC	1/22/2021	1964	RET ABN	UG-SERVICE
36739208	GRET	SVC	8/3/2020	1964	RET ABN	UG-SERVICE
41877225	GRET	SVC	7/14/2023	1964	RET ABN	UG-SERVICE
42224958	GRET	SVC	7/22/2024	1964	RET ABN	UG-SERVICE
39380912	GRET	SVC	11/11/2021	1964	RET ABN	UG-SERVICE
43612806	GRET	SVC	11/18/2024	1964	RET ABN	UG-SERVICE
38426940	GRET	SVC	3/22/2021	1964	RET ABN	UG-SERVICE
35882772	GRET	SVC	1/13/2020	1964	RET ABN	UG-SERVICE
39224591	GRET	SVC	9/29/2021	1964	RET ABN	UG-SERVICE
36135880	GRET	SVC	4/21/2020	1964	RET ABN	UG-SERVICE
36672270	GRET	SVC	9/28/2020	1964	RET ABN	UG-SERVICE
40727980	GRET	SVC	9/20/2022	1964	RET ABN	UG-SERVICE
36106819	GRET	SVC	10/12/2020	1964	RET ABN	UG-SERVICE
39496778	GRET	SVC	12/1/2021	1964	RET ABN	UG-SERVICE
42587967	GRET	SVC	8/1/2024	1964	RET ABN	UG-SERVICE
42813703	GRET	SVC	3/8/2024	1964	RET ABN	UG-SERVICE
39078774	GRET	SVC	9/14/2021	1964	RET ABN	UG-SERVICE
42057080	GRET	SVC	10/30/2023	1964	RET ABN	UG-SERVICE
40182832	GRET	SVC	6/7/2022	1964	RET ABN	UG-SERVICE
42586642	GRET	SVC	2/8/2024	1964	RET ABN	UG-SERVICE
36638130	GRET	SVC	7/20/2020	1964	RET ABN	UG-SERVICE
36214903	GRET	SVC	4/28/2020	1964	RET ABN	UG-SERVICE
36259645	GRET	SVC	4/22/2020	1964	RET ABN	UG-SERVICE
42566813	GRET	SVC	1/16/2024	1964	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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36821064	GRET	SVC	11/12/2020	1964	RET ABN	UG-SERVICE
42870885	GRET	SVC	5/20/2024	1964	RET ABN	UG-SERVICE
36425578	GRET	SVC	5/14/2020	1964	RET ABN	UG-SERVICE
40513282	GRET	SVC	8/2/2022	1964	RET ABN	UG-SERVICE
38353013	GRET	SVC	2/14/2023	1964	RET ABN	UG-SERVICE
41407665	GRET	SVC	4/2/2024	1964	RET ABN	UG-SERVICE
41969660	GRET	SVC	8/1/2024	1964	RET ABN	UG-SERVICE
38487654	GRET	SVC	5/18/2021	1964	RET ABN	UG-SERVICE
38169140	GRET	SVC	3/9/2021	1964	RET ABN	UG-SERVICE
39304392	GRET	SVC	10/20/2021	1964	RET ABN	UG-SERVICE
41497750	GRET	SVC	5/3/2023	1964	RET ABN	UG-SERVICE
37357286	GRET	SVC	11/10/2020	1964	RET ABN	UG-SERVICE
43643658	GRET	SVC	10/7/2024	1964	RET ABN	UG-SERVICE
37082530	GRET	SVC	10/15/2020	1964	RET ABN	UG-SERVICE
40578228	GRET	SVC	8/26/2022	1964	RET ABN	UG-SERVICE
43229385	GRET	SVC	6/28/2024	1964	RET ABN	UG-SERVICE
40860481	GRET	SVC	10/28/2022	1964	RET ABN	UG-SERVICE
40865919	GRET	SVC	8/22/2023	1964	RET ABN	UG-SERVICE
42068574	GRET	SVC	9/6/2023	1964	RET ABN	UG-SERVICE
43650235	GRET	SVC	10/4/2024	1964	RET ABN	UG-SERVICE
41969652	GRET	SVC	8/1/2024	1964	RET ABN	UG-SERVICE
38221350	GRET	SVC	3/3/2021	1964	RET ABN	UG-SERVICE
39935384	GRET	SVC	5/14/2022	1964	RET ABN	UG-SERVICE
36313897	GRET	SVC	6/8/2020	1964	RET ABN	UG-SERVICE
38352839	GRET	SVC	5/5/2021	1964	RET ABN	UG-SERVICE
40827499	GRET	SVC	11/2/2022	1964	RET ABN	UG-SERVICE
41114168	GRET	SVC	1/12/2023	1964	RET ABN	UG-SERVICE
43715920	GRET	SVC	10/24/2024	1964	RET ABN	UG-SERVICE
41829854	GRET	SVC	7/13/2023	1964	RET ABN	UG-SERVICE
41247067	GRET	SVC	2/8/2023	1964	RET ABN	UG-SERVICE
36766246	GRET	SVC	8/11/2020	1964	RET ABN	UG-SERVICE
42892210	GRET	SVC	4/30/2024	1964	RET ABN	UG-SERVICE
38474292	GRET	SVC	3/30/2021	1964	RET ABN	UG-SERVICE
43244751	GRET	SVC	12/17/2024	1964	RET ABN	UG-SERVICE
43942523	GRET	SVC	12/17/2024	1964	RET ABN	UG-SERVICE
41821731	GRET	SVC	7/3/2023	1964	RET ABN	UG-SERVICE
42344673	GRET	SVC	11/8/2023	1964	RET ABN	UG-SERVICE
41114059	GRET	SVC	1/4/2023	1964	RET ABN	UG-SERVICE
38697774	GRET	SVC	7/6/2021	1964	RET ABN	UG-SERVICE
40561330	GRET	SVC	8/27/2022	1964	RET ABN	UG-SERVICE
42897389	GRET	SVC	9/11/2024	1964	RET ABN	UG-SERVICE
37142034	GRET	SVC	10/31/2020	1964	RET ABN	UG-SERVICE
41194402	GRET	SVC	1/23/2023	1964	RET ABN	UG-SERVICE
42122263	GRET	SVC	9/14/2023	1964	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40389018	GRET	SVC	7/22/2022	1964	RET ABN	UG-SERVICE
40139577	GRET	SVC	5/18/2022	1964	RET ABN	UG-SERVICE
39657982	GRET	SVC	2/18/2022	1964	RET ABN	UG-SERVICE
41262153	GRET	SVC	3/20/2023	1964	RET ABN	UG-SERVICE
40394666	GRET	SVC	7/6/2022	1964	RET ABN	UG-SERVICE
37993927	GRET	SVC	1/11/2021	1964	RET ABN	UG-SERVICE
38390547	GRET	SVC	4/20/2021	1964	RET ABN	UG-SERVICE
43952060	GRET	SVC	12/17/2024	1964	RET ABN	UG-SERVICE
36122502	GRET	SVC	10/30/2020	1964	RET ABN	UG-SERVICE
42952137	GRET	SVC	4/20/2024	1964	RET ABN	UG-SERVICE
39666586	GRET	SVC	1/6/2022	1964	RET ABN	UG-SERVICE
41082589	GRET	SVC	12/21/2022	1964	RET ABN	UG-SERVICE
43379779	GRET	SVC	8/1/2024	1964	RET ABN	UG-SERVICE
41472351	GRET	SVC	5/5/2023	1964	RET ABN	UG-SERVICE
38510812	GRET	SVC	5/17/2021	1964	RET ABN	UG-SERVICE
41222710	GRET	SVC	5/8/2023	1964	RET ABN	UG-SERVICE
40449448	GRET	SVC	7/18/2022	1964	RET ABN	UG-SERVICE
40197873	GRET	SVC	6/6/2022	1964	RET ABN	UG-SERVICE
38109700	GRET	SVC	2/10/2021	1964	RET ABN	UG-SERVICE
36606201	GRET	SVC	7/9/2020	1964	RET ABN	UG-SERVICE
40208810	GRET	SVC	5/26/2022	1964	RET ABN	UG-SERVICE
41223591	GRET	SVC	2/3/2023	1964	RET ABN	UG-SERVICE
38141922	GRET	SVC	2/16/2021	1964	RET ABN	UG-SERVICE
41018644	GRET	SVC	12/8/2022	1964	RET ABN	UG-SERVICE
41411666	GRET	SVC	4/2/2024	1964	RET ABN	UG-SERVICE
38263831	GRET	SVC	3/22/2021	1964	RET ABN	UG-SERVICE
37039775	GRET	SVC	10/5/2020	1964	RET ABN	UG-SERVICE
41830199	GRET	SVC	8/10/2023	1964	RET ABN	UG-SERVICE
41556176	GRET	SVC	4/24/2023	1964	RET ABN	UG-SERVICE
40127065	GRET	SVC	5/5/2022	1964	RET ABN	UG-SERVICE
36366994	GRET	SVC	5/26/2020	1964	RET ABN	UG-SERVICE
36153329	GRET	SVC	3/25/2020	1964	RET ABN	UG-SERVICE
36041230	GRET	SVC	2/19/2020	1964	RET ABN	UG-SERVICE
41424028	GRET	SVC	10/18/2023	1964	RET ABN	UG-SERVICE
36136100	GRET	SVC	4/23/2020	1964	RET ABN	UG-SERVICE
42833920	GRET	SVC	7/22/2024	1964	RET ABN	UG-SERVICE
37014743	GRET	SVC	10/2/2020	1964	RET ABN	UG-SERVICE
36147555	GRET	SVC	1/6/2021	1964	RET ABN	UG-SERVICE
36135912	GRET	SVC	4/23/2020	1964	RET ABN	UG-SERVICE
39431224	GRET	SVC	11/15/2021	1964	RET ABN	UG-SERVICE
36152340	GRET	SVC	3/19/2020	1964	RET ABN	UG-SERVICE
36881990	GRET	SVC	8/30/2020	1964	RET ABN	UG-SERVICE
36906875	GRET	SVC	9/9/2020	1964	RET ABN	UG-SERVICE
36118901	GRET	SVC	10/12/2020	1964	RET ABN	UG-SERVICE
41802972	GRET	SVC	6/26/2023	1964	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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39081585	GRET	SVC	9/8/2021	1964	RET ABN	UG-SERVICE
37122072	GRET	SVC	10/30/2020	1964	RET ABN	UG-SERVICE
38234185	GRET	SVC	8/24/2021	1964	RET ABN	UG-SERVICE
36107011	GRET	SVC	4/27/2020	1964	RET ABN	UG-SERVICE
38569061	GRET	SVC	6/9/2021	1964	RET ABN	UG-SERVICE
36777009	GRET	SVC	8/13/2020	1964	RET ABN	UG-SERVICE
35863545	GRET	SVC	1/23/2020	1964	RET ABN	UG-SERVICE
36102844	GRET	SVC	4/21/2020	1964	RET ABN	UG-SERVICE
40498177	GRET	SVC	9/16/2022	1964	RET ABN	UG-SERVICE
43901494	GRET	SVC	11/19/2024	1965	RET ABN	UG-SERVICE
42427178	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
39211546	GRET	SVC	9/28/2021	1965	RET ABN	UG-SERVICE
36102274	GRET	SVC	4/23/2020	1965	RET ABN	UG-SERVICE
39666604	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
36732666	GRET	SVC	7/30/2020	1965	RET ABN	UG-SERVICE
42224937	GRET	SVC	10/16/2023	1965	RET ABN	UG-SERVICE
42455479	GRET	SVC	12/12/2023	1965	RET ABN	UG-SERVICE
36867895	GRET	SVC	10/11/2020	1965	RET ABN	UG-SERVICE
39721546	GRET	SVC	1/24/2022	1965	RET ABN	UG-SERVICE
38239042	GRET	SVC	3/15/2021	1965	RET ABN	UG-SERVICE
36122366	GRET	SVC	10/30/2020	1965	RET ABN	UG-SERVICE
38057493	GRET	SVC	1/26/2021	1965	RET ABN	UG-SERVICE
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36136110	GRET	SVC	4/21/2020	1965	RET ABN	UG-SERVICE
41106895	GRET	SVC	1/4/2023	1965	RET ABN	UG-SERVICE
41321357	GRET	SVC	3/16/2023	1965	RET ABN	UG-SERVICE
42427221	GRET	SVC	11/20/2023	1965	RET ABN	UG-SERVICE
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37643324	GRET	SVC	11/17/2020	1965	RET ABN	UG-SERVICE
42899874	GRET	SVC	4/9/2024	1965	RET ABN	UG-SERVICE
41140336	GRET	SVC	1/6/2023	1965	RET ABN	UG-SERVICE
42427222	GRET	SVC	11/20/2023	1965	RET ABN	UG-SERVICE
43124066	GRET	SVC	6/3/2024	1965	RET ABN	UG-SERVICE
39858317	GRET	SVC	3/9/2022	1965	RET ABN	UG-SERVICE
42177398	GRET	SVC	10/3/2023	1965	RET ABN	UG-SERVICE
39666609	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
43650230	GRET	SVC	10/10/2024	1965	RET ABN	UG-SERVICE
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36108165	GRET	SVC	4/24/2020	1965	RET ABN	UG-SERVICE
38512595	GRET	SVC	5/20/2021	1965	RET ABN	UG-SERVICE
38110997	GRET	SVC	2/11/2021	1965	RET ABN	UG-SERVICE
42196724	GRET	SVC	10/9/2023	1965	RET ABN	UG-SERVICE
33904524	GRET	SVC	7/22/2020	1965	RET ABN	UG-SERVICE
39423499	GRET	SVC	6/27/2022	1965	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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36085786	GRET	SVC	2/27/2020	1965	RET ABN	UG-SERVICE
40558512	GRET	SVC	8/20/2022	1965	RET ABN	UG-SERVICE
41277890	GRET	SVC	3/1/2023	1965	RET ABN	UG-SERVICE
41450121	GRET	SVC	3/30/2023	1965	RET ABN	UG-SERVICE
38184601	GRET	SVC	3/12/2021	1965	RET ABN	UG-SERVICE
39791342	GRET	SVC	11/5/2021	1965	RET ABN	UG-SERVICE
42958049	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
38536854	GRET	SVC	6/30/2021	1965	RET ABN	UG-SERVICE
36118404	GRET	SVC	3/11/2020	1965	RET ABN	UG-SERVICE
38658886	GRET	SVC	6/24/2021	1965	RET ABN	UG-SERVICE
40416700	GRET	SVC	12/12/2022	1965	RET ABN	UG-SERVICE
38664243	GRET	SVC	7/7/2021	1965	RET ABN	UG-SERVICE
32784854	GRET	SVC	3/17/2020	1965	RET ABN	UG-SERVICE
39931524	GRET	SVC	4/28/2022	1965	RET ABN	UG-SERVICE
42165247	GRET	SVC	10/10/2023	1965	RET ABN	UG-SERVICE
39337452	GRET	SVC	10/28/2021	1965	RET ABN	UG-SERVICE
41411663	GRET	SVC	4/2/2024	1965	RET ABN	UG-SERVICE
38912991	GRET	SVC	8/11/2021	1965	RET ABN	UG-SERVICE
41423576	GRET	SVC	10/18/2023	1965	RET ABN	UG-SERVICE
39935323	GRET	SVC	5/2/2022	1965	RET ABN	UG-SERVICE
42509259	GRET	SVC	7/31/2024	1965	RET ABN	UG-SERVICE
42293731	GRET	SVC	10/31/2023	1965	RET ABN	UG-SERVICE
36961508	GRET	SVC	9/21/2020	1965	RET ABN	UG-SERVICE
38792416	GRET	SVC	7/20/2021	1965	RET ABN	UG-SERVICE
37529540	GRET	SVC	11/16/2020	1965	RET ABN	UG-SERVICE
43881681	GRET	SVC	11/13/2024	1965	RET ABN	UG-SERVICE
42509256	GRET	SVC	7/18/2024	1965	RET ABN	UG-SERVICE
43881682	GRET	SVC	12/6/2024	1965	RET ABN	UG-SERVICE
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42427119	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
43245027	GRET	SVC	9/11/2024	1965	RET ABN	UG-SERVICE
39464875	GRET	SVC	12/12/2021	1965	RET ABN	UG-SERVICE
39484726	GRET	SVC	10/22/2021	1965	RET ABN	UG-SERVICE
36040145	GRET	SVC	2/4/2020	1965	RET ABN	UG-SERVICE
43365686	GRET	SVC	12/3/2024	1965	RET ABN	UG-SERVICE
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42182890	GRET	SVC	10/3/2023	1965	RET ABN	UG-SERVICE
42958176	GRET	SVC	4/22/2024	1965	RET ABN	UG-SERVICE
38169073	GRET	SVC	2/25/2021	1965	RET ABN	UG-SERVICE
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order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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36108169	GRET	SVC	4/24/2020	1965	RET ABN	UG-SERVICE
39331838	GRET	SVC	10/28/2021	1965	RET ABN	UG-SERVICE
42144500	GRET	SVC	9/26/2023	1965	RET ABN	UG-SERVICE
41330853	GRET	SVC	3/9/2023	1965	RET ABN	UG-SERVICE
39666603	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
39581411	GRET	SVC	12/20/2021	1965	RET ABN	UG-SERVICE
43081838	GRET	SVC	5/22/2024	1965	RET ABN	UG-SERVICE
39935336	GRET	SVC	6/21/2022	1965	RET ABN	UG-SERVICE
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42957223	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
39341152	GRET	SVC	10/26/2021	1965	RET ABN	UG-SERVICE
39666608	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
39725976	GRET	SVC	1/26/2022	1965	RET ABN	UG-SERVICE
39739149	GRET	SVC	1/31/2022	1965	RET ABN	UG-SERVICE
36885289	GRET	SVC	10/14/2020	1965	RET ABN	UG-SERVICE
40370330	GRET	SVC	7/6/2022	1965	RET ABN	UG-SERVICE
38040097	GRET	SVC	1/28/2021	1965	RET ABN	UG-SERVICE
41237590	GRET	SVC	2/6/2023	1965	RET ABN	UG-SERVICE
36102857	GRET	SVC	4/22/2020	1965	RET ABN	UG-SERVICE
43183971	GRET	SVC	6/18/2024	1965	RET ABN	UG-SERVICE
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43623541	GRET	SVC	12/16/2024	1965	RET ABN	UG-SERVICE
38014261	GRET	SVC	1/11/2021	1965	RET ABN	UG-SERVICE
38311563	GRET	SVC	4/5/2021	1965	RET ABN	UG-SERVICE
42487348	GRET	SVC	7/18/2024	1965	RET ABN	UG-SERVICE
39519787	GRET	SVC	12/12/2021	1965	RET ABN	UG-SERVICE
42008727	GRET	SVC	8/14/2023	1965	RET ABN	UG-SERVICE
42207966	GRET	SVC	7/18/2024	1965	RET ABN	UG-SERVICE
41807608	GRET	SVC	6/27/2023	1965	RET ABN	UG-SERVICE
40313094	GRET	SVC	6/16/2022	1965	RET ABN	UG-SERVICE
36636735	GRET	SVC	7/16/2020	1965	RET ABN	UG-SERVICE
43245061	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
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36108161	GRET	SVC	4/24/2020	1965	RET ABN	UG-SERVICE
39666605	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
40726492	GRET	SVC	9/23/2022	1965	RET ABN	UG-SERVICE
36136185	GRET	SVC	4/28/2020	1965	RET ABN	UG-SERVICE
42957943	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
39423535	GRET	SVC	6/27/2022	1965	RET ABN	UG-SERVICE
43423330	GRET	SVC	9/11/2024	1965	RET ABN	UG-SERVICE
42812485	GRET	SVC	3/12/2024	1965	RET ABN	UG-SERVICE
36122121	GRET	SVC	10/14/2020	1965	RET ABN	UG-SERVICE
39730825	GRET	SVC	4/29/2021	1965	RET ABN	UG-SERVICE
38712739	GRET	SVC	7/2/2021	1965	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41274141	GRET	SVC	2/15/2023	1965	RET ABN	UG-SERVICE
41427598	GRET	SVC	4/14/2023	1965	RET ABN	UG-SERVICE
36743332	GRET	SVC	8/21/2020	1965	RET ABN	UG-SERVICE
42202951	GRET	SVC	10/9/2023	1965	RET ABN	UG-SERVICE
36829577	GRET	SVC	8/26/2020	1965	RET ABN	UG-SERVICE
42409061	GRET	SVC	11/22/2023	1965	RET ABN	UG-SERVICE
39666601	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
42473588	GRET	SVC	12/12/2023	1965	RET ABN	UG-SERVICE
41211356	GRET	SVC	12/11/2023	1965	RET ABN	UG-SERVICE
39423741	GRET	SVC	6/27/2022	1965	RET ABN	UG-SERVICE
41989714	GRET	SVC	8/18/2023	1965	RET ABN	UG-SERVICE
37900138	GRET	SVC	12/11/2020	1965	RET ABN	UG-SERVICE
42363567	GRET	SVC	11/28/2023	1965	RET ABN	UG-SERVICE
41472419	GRET	SVC	10/6/2023	1965	RET ABN	UG-SERVICE
36878133	GRET	SVC	9/1/2020	1965	RET ABN	UG-SERVICE
39928912	GRET	SVC	4/12/2022	1965	RET ABN	UG-SERVICE
42522466	GRET	SVC	12/28/2023	1965	RET ABN	UG-SERVICE
39952104	GRET	SVC	5/13/2022	1965	RET ABN	UG-SERVICE
36228453	GRET	SVC	4/22/2020	1965	RET ABN	UG-SERVICE
36795121	GRET	SVC	8/18/2020	1965	RET ABN	UG-SERVICE
36670564	GRET	SVC	7/22/2020	1965	RET ABN	UG-SERVICE
40359182	GRET	SVC	6/30/2022	1965	RET ABN	UG-SERVICE
43365684	GRET	SVC	11/20/2024	1965	RET ABN	UG-SERVICE
38577087	GRET	SVC	6/7/2021	1965	RET ABN	UG-SERVICE
42029486	GRET	SVC	8/24/2023	1965	RET ABN	UG-SERVICE
39666671	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
43245060	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
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36177520	GRET	SVC	2/14/2020	1965	RET ABN	UG-SERVICE
39666606	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
40420598	GRET	SVC	7/22/2022	1965	RET ABN	UG-SERVICE
39725934	GRET	SVC	1/26/2022	1965	RET ABN	UG-SERVICE
36473508	GRET	SVC	6/22/2020	1965	RET ABN	UG-SERVICE
38740519	GRET	SVC	7/12/2021	1965	RET ABN	UG-SERVICE
39666494	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
39220431	GRET	SVC	9/29/2021	1965	RET ABN	UG-SERVICE
41534819	GRET	SVC	4/18/2023	1965	RET ABN	UG-SERVICE
43881519	GRET	SVC	11/13/2024	1965	RET ABN	UG-SERVICE
39858318	GRET	SVC	3/9/2022	1965	RET ABN	UG-SERVICE
43766464	GRET	SVC	10/29/2024	1965	RET ABN	UG-SERVICE
40103536	GRET	SVC	4/27/2022	1965	RET ABN	UG-SERVICE
41088830	GRET	SVC	1/31/2023	1965	RET ABN	UG-SERVICE
39666493	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36137647	GRET	SVC	4/20/2020	1965	RET ABN	UG-SERVICE
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43423334	GRET	SVC	9/11/2024	1965	RET ABN	UG-SERVICE
39536549	GRET	SVC	12/13/2021	1965	RET ABN	UG-SERVICE
39395625	GRET	SVC	11/7/2021	1965	RET ABN	UG-SERVICE
41505539	GRET	SVC	4/12/2023	1965	RET ABN	UG-SERVICE
39656535	GRET	SVC	3/1/2022	1965	RET ABN	UG-SERVICE
37707219	GRET	SVC	12/8/2020	1965	RET ABN	UG-SERVICE
41423577	GRET	SVC	10/18/2023	1965	RET ABN	UG-SERVICE
41830302	GRET	SVC	8/11/2023	1965	RET ABN	UG-SERVICE
42363564	GRET	SVC	11/28/2023	1965	RET ABN	UG-SERVICE
42427223	GRET	SVC	11/20/2023	1965	RET ABN	UG-SERVICE
36122373	GRET	SVC	10/14/2020	1965	RET ABN	UG-SERVICE
37045733	GRET	SVC	10/14/2020	1965	RET ABN	UG-SERVICE
39666498	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
42957392	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
39661046	GRET	SVC	1/28/2022	1965	RET ABN	UG-SERVICE
42337726	GRET	SVC	1/26/2024	1965	RET ABN	UG-SERVICE
42833356	GRET	SVC	7/22/2024	1965	RET ABN	UG-SERVICE
39935372	GRET	SVC	5/14/2022	1965	RET ABN	UG-SERVICE
39725933	GRET	SVC	1/26/2022	1965	RET ABN	UG-SERVICE
40979415	GRET	SVC	11/28/2022	1965	RET ABN	UG-SERVICE
39225182	GRET	SVC	10/8/2021	1965	RET ABN	UG-SERVICE
41742291	GRET	SVC	7/25/2023	1965	RET ABN	UG-SERVICE
38496924	GRET	SVC	4/2/2021	1965	RET ABN	UG-SERVICE
42958101	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
38617543	GRET	SVC	6/13/2021	1965	RET ABN	UG-SERVICE
37706318	GRET	SVC	11/20/2020	1965	RET ABN	UG-SERVICE
43646437	GRET	SVC	10/2/2024	1965	RET ABN	UG-SERVICE
42363560	GRET	SVC	11/28/2023	1965	RET ABN	UG-SERVICE
42957329	GRET	SVC	9/19/2024	1965	RET ABN	UG-SERVICE
36260066	GRET	SVC	3/19/2020	1965	RET ABN	UG-SERVICE
39654865	GRET	SVC	6/28/2022	1965	RET ABN	UG-SERVICE
42270107	GRET	SVC	11/2/2023	1965	RET ABN	UG-SERVICE
37978600	GRET	SVC	1/6/2021	1965	RET ABN	UG-SERVICE
37983192	GRET	SVC	1/6/2021	1965	RET ABN	UG-SERVICE
40266802	GRET	SVC	6/8/2022	1965	RET ABN	UG-SERVICE
39725954	GRET	SVC	1/26/2022	1965	RET ABN	UG-SERVICE
39666661	GRET	SVC	11/18/2022	1965	RET ABN	UG-SERVICE
40283204	GRET	SVC	6/7/2022	1965	RET ABN	UG-SERVICE
36080248	GRET	SVC	3/3/2020	1965	RET ABN	UG-SERVICE
38638023	GRET	SVC	6/16/2021	1965	RET ABN	UG-SERVICE
41052708	GRET	SVC	1/12/2023	1965	RET ABN	UG-SERVICE
42848846	GRET	SVC	3/19/2024	1965	RET ABN	UG-SERVICE
36152601	GRET	SVC	3/10/2020	1965	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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36838877	GRET	SVC	9/1/2020	1966	RET ABN	UG-SERVICE
42376902	GRET	SVC	11/22/2023	1966	RET ABN	UG-SERVICE
40978938	GRET	SVC	12/2/2022	1966	RET ABN	UG-SERVICE
38918860	GRET	SVC	8/17/2021	1966	RET ABN	UG-SERVICE
41204072	GRET	SVC	1/24/2023	1966	RET ABN	UG-SERVICE
41224415	GRET	SVC	2/3/2023	1966	RET REM	UG-SERVICE
41442094	GRET	SVC	3/28/2024	1966	RET ABN	UG-SERVICE
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40654496	GRET	SVC	9/6/2022	1966	RET ABN	UG-SERVICE
41273674	GRET	SVC	3/13/2023	1966	RET ABN	UG-SERVICE
36485524	GRET	SVC	6/23/2020	1966	RET ABN	UG-SERVICE
43330049	GRET	SVC	7/18/2024	1966	RET ABN	UG-SERVICE
36120845	GRET	SVC	10/12/2020	1966	RET ABN	UG-SERVICE
43423331	GRET	SVC	10/1/2024	1966	RET ABN	UG-SERVICE
37052009	GRET	SVC	10/12/2020	1966	RET ABN	UG-SERVICE
42273032	GRET	SVC	11/3/2023	1966	RET ABN	UG-SERVICE
40230897	GRET	SVC	5/31/2022	1966	RET ABN	UG-SERVICE
38909909	GRET	SVC	8/7/2021	1966	RET ABN	UG-SERVICE
40448088	GRET	SVC	7/12/2022	1966	RET ABN	UG-SERVICE
38193068	GRET	SVC	6/11/2021	1966	RET ABN	UG-SERVICE
41111500	GRET	SVC	1/4/2023	1966	RET ABN	UG-SERVICE
42388694	GRET	SVC	12/6/2023	1966	RET ABN	UG-SERVICE
41407590	GRET	SVC	4/2/2024	1966	RET ABN	UG-SERVICE
37866261	GRET	SVC	11/21/2020	1966	RET ABN	UG-SERVICE
43245037	GRET	SVC	9/19/2024	1966	RET ABN	UG-SERVICE
38992456	GRET	SVC	8/31/2021	1966	RET ABN	UG-SERVICE
41052711	GRET	SVC	1/12/2023	1966	RET ABN	UG-SERVICE
36951629	GRET	SVC	9/24/2020	1966	RET ABN	UG-SERVICE
40128247	GRET	SVC	7/6/2022	1966	RET ABN	UG-SERVICE
42910237	GRET	SVC	4/9/2024	1966	RET ABN	UG-SERVICE
41830303	GRET	SVC	8/11/2023	1966	RET ABN	UG-SERVICE
36157802	GRET	SVC	3/24/2020	1966	RET ABN	UG-SERVICE
42282770	GRET	SVC	10/24/2023	1966	RET ABN	UG-SERVICE
39725755	GRET	SVC	1/26/2022	1966	RET ABN	UG-SERVICE
39116215	GRET	SVC	9/13/2021	1966	RET ABN	UG-SERVICE
38391849	GRET	SVC	4/23/2021	1966	RET ABN	UG-SERVICE
37638488	GRET	SVC	11/17/2020	1966	RET ABN	UG-SERVICE
42580401	GRET	SVC	1/22/2024	1966	RET ABN	UG-SERVICE
36711652	GRET	SVC	8/5/2020	1966	RET ABN	UG-SERVICE
36058177	GRET	SVC	2/24/2020	1966	RET ABN	UG-SERVICE
43903742	GRET	SVC	11/20/2024	1966	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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40426965	GRET	SVC	7/22/2022	1966	RET ABN	UG-SERVICE
43252353	GRET	SVC	6/27/2024	1966	RET ABN	UG-SERVICE
41273672	GRET	SVC	2/15/2023	1966	RET ABN	UG-SERVICE
43446242	GRET	SVC	8/15/2024	1966	RET ABN	UG-SERVICE
42320774	GRET	SVC	11/6/2023	1966	RET ABN	UG-SERVICE
38356365	GRET	SVC	4/23/2021	1966	RET ABN	UG-SERVICE
41407589	GRET	SVC	4/2/2024	1966	RET ABN	UG-SERVICE
42276565	GRET	SVC	10/30/2023	1966	RET ABN	UG-SERVICE
39423750	GRET	SVC	6/27/2022	1966	RET ABN	UG-SERVICE
43523502	GRET	SVC	9/11/2024	1966	RET ABN	UG-SERVICE
36107792	GRET	SVC	4/24/2020	1966	RET ABN	UG-SERVICE
41388767	GRET	SVC	3/16/2023	1966	RET ABN	UG-SERVICE
43257608	GRET	SVC	7/2/2024	1966	RET ABN	UG-SERVICE
36915301	GRET	SVC	9/10/2020	1966	RET ABN	UG-SERVICE
36247036	GRET	SVC	4/3/2020	1966	RET ABN	UG-SERVICE
38401486	GRET	SVC	8/31/2021	1966	RET ABN	UG-SERVICE
43245032	GRET	SVC	9/19/2024	1966	RET ABN	UG-SERVICE
41407584	GRET	SVC	4/2/2024	1966	RET ABN	UG-SERVICE
39935350	GRET	SVC	5/14/2022	1966	RET ABN	UG-SERVICE
39831381	GRET	SVC	8/3/2022	1966	RET ABN	UG-SERVICE
40991241	GRET	SVC	12/3/2022	1966	RET ABN	UG-SERVICE
41349222	GRET	SVC	4/17/2023	1966	RET ABN	UG-SERVICE
40979006	GRET	SVC	12/2/2022	1966	RET ABN	UG-SERVICE
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36145871	GRET	SVC	3/17/2020	1966	RET ABN	UG-SERVICE
39513499	GRET	SVC	12/6/2021	1966	RET ABN	UG-SERVICE
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36122126	GRET	SVC	10/30/2020	1966	RET ABN	UG-SERVICE
36136193	GRET	SVC	4/20/2020	1966	RET ABN	UG-SERVICE
39153977	GRET	SVC	8/2/2021	1966	RET ABN	UG-SERVICE
36109957	GRET	SVC	4/22/2020	1966	RET ABN	UG-SERVICE
43522786	GRET	SVC	9/3/2024	1966	RET ABN	UG-SERVICE
36183828	GRET	SVC	3/30/2020	1966	RET ABN	UG-SERVICE
43256912	GRET	SVC	7/17/2024	1966	RET ABN	UG-SERVICE
36751428	GRET	SVC	10/5/2020	1966	RET ABN	UG-SERVICE
41062433	GRET	SVC	12/14/2022	1966	RET ABN	UG-SERVICE
38912078	GRET	SVC	11/4/2021	1966	RET ABN	UG-SERVICE
43245040	GRET	SVC	9/19/2024	1966	RET ABN	UG-SERVICE
38741028	GRET	SVC	7/28/2021	1966	RET ABN	UG-SERVICE
39353378	GRET	SVC	11/1/2021	1966	RET ABN	UG-SERVICE
43481242	GRET	SVC	10/25/2024	1966	RET ABN	UG-SERVICE
38378981	GRET	SVC	6/28/2021	1966	RET ABN	UG-SERVICE
36107163	GRET	SVC	4/23/2020	1966	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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38305182	GRET	SVC	4/5/2021	1966	RET ABN	UG-SERVICE
36122125	GRET	SVC	10/30/2020	1966	RET ABN	UG-SERVICE
39319507	GRET	SVC	10/20/2021	1966	RET ABN	UG-SERVICE
40332412	GRET	SVC	6/28/2022	1966	RET ABN	UG-SERVICE
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40500613	GRET	SVC	8/20/2022	1966	RET ABN	UG-SERVICE
41408288	GRET	SVC	4/2/2024	1966	RET ABN	UG-SERVICE
41407875	GRET	SVC	4/6/2023	1966	RET ABN	UG-SERVICE
37047386	GRET	SVC	4/15/2021	1966	RET ABN	UG-SERVICE
38564394	GRET	SVC	6/21/2021	1966	RET ABN	UG-SERVICE
42898274	GRET	SVC	4/8/2024	1966	RET ABN	UG-SERVICE
36177521	GRET	SVC	2/14/2020	1966	RET ABN	UG-SERVICE
38416170	GRET	SVC	4/27/2021	1966	RET ABN	UG-SERVICE
43171328	GRET	SVC	6/11/2024	1966	RET ABN	UG-SERVICE
39875729	GRET	SVC	5/18/2022	1966	RET ABN	UG-SERVICE
43245044	GRET	SVC	9/11/2024	1966	RET ABN	UG-SERVICE
43245049	GRET	SVC	9/11/2024	1966	RET ABN	UG-SERVICE
40654907	GRET	SVC	9/4/2022	1966	RET ABN	UG-SERVICE
43529749	GRET	SVC	10/21/2024	1966	RET ABN	UG-SERVICE
36797243	GRET	SVC	8/17/2020	1966	RET ABN	UG-SERVICE
40717084	GRET	SVC	9/20/2022	1966	RET ABN	UG-SERVICE
43245048	GRET	SVC	9/11/2024	1966	RET ABN	UG-SERVICE
41179359	GRET	SVC	1/20/2023	1966	RET ABN	UG-SERVICE
36406483	GRET	SVC	6/22/2020	1966	RET ABN	UG-SERVICE
43005042	GRET	SVC	9/19/2024	1966	RET ABN	UG-SERVICE
43474345	GRET	SVC	8/22/2024	1966	RET ABN	UG-SERVICE
41283639	GRET	SVC	2/21/2023	1966	RET ABN	UG-SERVICE
36107796	GRET	SVC	4/24/2020	1966	RET ABN	UG-SERVICE
42549484	GRET	SVC	1/4/2024	1966	RET ABN	UG-SERVICE
41407592	GRET	SVC	4/2/2024	1966	RET ABN	UG-SERVICE
42046170	GRET	SVC	8/28/2023	1966	RET ABN	UG-SERVICE
39231670	GRET	SVC	9/30/2021	1966	RET ABN	UG-SERVICE
38407207	GRET	SVC	3/19/2021	1966	RET ABN	UG-SERVICE
40798417	GRET	SVC	10/10/2022	1966	RET ABN	UG-SERVICE
36107783	GRET	SVC	4/24/2020	1966	RET ABN	UG-SERVICE
39324017	GRET	SVC	10/19/2021	1966	RET ABN	UG-SERVICE
41472721	GRET	SVC	7/12/2023	1966	RET ABN	UG-SERVICE
40691456	GRET	SVC	9/14/2022	1966	RET ABN	UG-SERVICE
43318163	GRET	SVC	8/5/2024	1966	RET ABN	UG-SERVICE
39831374	GRET	SVC	8/3/2022	1966	RET ABN	UG-SERVICE
40798329	GRET	SVC	10/10/2022	1966	RET ABN	UG-SERVICE
43229977	GRET	SVC	6/25/2024	1966	RET ABN	UG-SERVICE
39192329	GRET	SVC	9/30/2021	1966	RET ABN	UG-SERVICE
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order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39423859	GRET	SVC	6/27/2022	1966	RET ABN	UG-SERVICE
41124022	GRET	SVC	1/4/2023	1966	RET ABN	UG-SERVICE
42957221	GRET	SVC	9/19/2024	1966	RET ABN	UG-SERVICE
38844638	GRET	SVC	7/27/2021	1966	RET ABN	UG-SERVICE
38470298	GRET	SVC	3/29/2021	1966	RET ABN	UG-SERVICE
36107790	GRET	SVC	4/24/2020	1966	RET ABN	UG-SERVICE
43423332	GRET	SVC	10/1/2024	1966	RET ABN	UG-SERVICE
39614518	GRET	SVC	12/29/2021	1966	RET ABN	UG-SERVICE
42885139	GRET	SVC	4/5/2024	1966	RET ABN	UG-SERVICE
38390575	GRET	SVC	4/20/2021	1966	RET ABN	UG-SERVICE
38443004	GRET	SVC	5/4/2021	1966	RET ABN	UG-SERVICE
40806281	GRET	SVC	10/13/2022	1966	RET ABN	UG-SERVICE
36107788	GRET	SVC	4/24/2020	1966	RET ABN	UG-SERVICE
41407548	GRET	SVC	4/2/2024	1966	RET ABN	UG-SERVICE
40493050	GRET	SVC	7/26/2022	1966	RET ABN	UG-SERVICE
37110282	GRET	SVC	10/21/2020	1966	RET ABN	UG-SERVICE
42678874	GRET	SVC	2/6/2024	1966	RET ABN	UG-SERVICE
36287104	GRET	SVC	5/5/2020	1966	RET ABN	UG-SERVICE
43330681	GRET	SVC	8/13/2024	1966	RET ABN	UG-SERVICE
38936703	GRET	SVC	8/4/2021	1966	RET ABN	UG-SERVICE
43060420	GRET	SVC	6/4/2024	1966	RET ABN	UG-SERVICE
36201750	GRET	SVC	4/20/2020	1966	RET ABN	UG-SERVICE
36599915	GRET	SVC	7/2/2020	1966	RET ABN	UG-SERVICE
38492277	GRET	SVC	5/13/2021	1966	RET ABN	UG-SERVICE
36980369	GRET	SVC	9/23/2020	1966	RET ABN	UG-SERVICE
40484247	GRET	SVC	7/26/2022	1966	RET ABN	UG-SERVICE
36695968	GRET	SVC	9/17/2020	1966	RET ABN	UG-SERVICE
36109251	GRET	SVC	3/10/2020	1966	RET ABN	UG-SERVICE
43245033	GRET	SVC	9/19/2024	1966	RET ABN	UG-SERVICE
36109949	GRET	SVC	4/22/2020	1966	RET ABN	UG-SERVICE
38474293	GRET	SVC	3/30/2021	1966	RET ABN	UG-SERVICE
43408117	GRET	SVC	8/13/2024	1966	RET ABN	UG-SERVICE
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38309004	GRET	SVC	4/5/2021	1966	RET ABN	UG-SERVICE
42225324	GRET	SVC	6/14/2024	1966	RET ABN	UG-SERVICE
41441932	GRET	SVC	9/12/2023	1966	RET ABN	UG-SERVICE
42165916	GRET	SVC	9/19/2023	1966	RET ABN	UG-SERVICE
40396182	GRET	SVC	7/7/2022	1966	RET ABN	UG-SERVICE
43719270	GRET	SVC	10/21/2024	1966	RET ABN	UG-SERVICE
41934591	GRET	SVC	7/31/2023	1966	RET ABN	UG-SERVICE
41001867	GRET	SVC	11/28/2022	1966	RET ABN	UG-SERVICE
41035829	GRET	SVC	12/8/2022	1966	RET ABN	UG-SERVICE
39819175	GRET	SVC	3/3/2022	1966	RET ABN	UG-SERVICE
41035826	GRET	SVC	12/8/2022	1966	RET ABN	UG-SERVICE
43529750	GRET	SVC	10/21/2024	1966	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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43366073	GRET	SVC	12/19/2024	1966	RET ABN	UG-SERVICE
39868516	GRET	SVC	3/9/2022	1966	RET ABN	UG-SERVICE
38067134	GRET	SVC	1/27/2021	1966	RET ABN	UG-SERVICE
42943660	GRET	SVC	7/17/2024	1966	RET ABN	UG-SERVICE
32785206	GRET	SVC	3/5/2020	1966	RET ABN	UG-SERVICE
36881998	GRET	SVC	9/2/2020	1966	RET ABN	UG-SERVICE
43401010	GRET	SVC	8/12/2024	1966	RET ABN	UG-SERVICE
37958746	GRET	SVC	12/29/2020	1966	RET ABN	UG-SERVICE
42327270	GRET	SVC	11/6/2023	1966	RET ABN	UG-SERVICE
42517348	GRET	SVC	12/28/2023	1966	RET ABN	UG-SERVICE
36137641	GRET	SVC	4/20/2020	1966	RET ABN	UG-SERVICE
41051918	GRET	SVC	1/12/2023	1966	RET ABN	UG-SERVICE
42844721	GRET	SVC	3/6/2024	1966	RET ABN	UG-SERVICE
39831379	GRET	SVC	8/3/2022	1966	RET ABN	UG-SERVICE
36734672	GRET	SVC	8/3/2020	1966	RET ABN	UG-SERVICE
36137138	GRET	SVC	4/21/2020	1966	RET ABN	UG-SERVICE
41411141	GRET	SVC	4/2/2024	1966	RET ABN	UG-SERVICE
38470224	GRET	SVC	5/11/2021	1966	RET ABN	UG-SERVICE
41020776	GRET	SVC	12/14/2022	1966	RET ABN	UG-SERVICE
41213128	GRET	SVC	1/30/2023	1966	RET ABN	UG-SERVICE
42956943	GRET	SVC	9/19/2024	1966	RET ABN	UG-SERVICE
40187487	GRET	SVC	5/18/2022	1966	RET ABN	UG-SERVICE
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37927124	GRET	SVC	12/15/2020	1966	RET ABN	UG-SERVICE
41913456	GRET	SVC	7/26/2023	1966	RET ABN	UG-SERVICE
43869730	GRET	SVC	11/26/2024	1966	RET ABN	UG-SERVICE
40050122	GRET	SVC	4/26/2022	1966	RET ABN	UG-SERVICE
36596780	GRET	SVC	7/9/2020	1966	RET ABN	UG-SERVICE
40976897	GRET	SVC	11/23/2022	1966	RET ABN	UG-SERVICE
39168281	GRET	SVC	9/22/2021	1966	RET ABN	UG-SERVICE
39814288	GRET	SVC	2/21/2022	1966	RET ABN	UG-SERVICE
41564104	GRET	SVC	4/24/2023	1966	RET ABN	UG-SERVICE
38379345	GRET	SVC	6/26/2021	1966	RET ABN	UG-SERVICE
36150722	GRET	SVC	3/23/2020	1967	RET ABN	UG-SERVICE
42605867	GRET	SVC	1/18/2024	1967	RET ABN	UG-SERVICE
41411749	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
41898045	GRET	SVC	9/15/2023	1967	RET ABN	UG-SERVICE
38088945	GRET	SVC	2/3/2021	1967	RET ABN	UG-SERVICE
43593171	GRET	SVC	9/23/2024	1967	RET ABN	UG-SERVICE
39126411	GRET	SVC	9/13/2021	1967	RET ABN	UG-SERVICE
38713600	GRET	SVC	7/15/2021	1967	RET ABN	UG-SERVICE
36107419	GRET	SVC	3/9/2020	1967	RET ABN	UG-SERVICE
38804672	GRET	SVC	8/2/2021	1967	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38441366	GRET	SVC	1/6/2022	1967	RET ABN	UG-SERVICE
41402745	GRET	SVC	11/2/2023	1967	RET ABN	UG-SERVICE
43010129	GRET	SVC	5/9/2024	1967	RET ABN	UG-SERVICE
36880787	GRET	SVC	9/3/2020	1967	RET ABN	UG-SERVICE
40662648	GRET	SVC	9/16/2022	1967	RET ABN	UG-SERVICE
39665818	GRET	SVC	8/3/2022	1967	RET ABN	UG-SERVICE
41572254	GRET	SVC	5/1/2023	1967	RET ABN	UG-SERVICE
41679178	GRET	SVC	6/18/2023	1967	RET ABN	UG-SERVICE
42385646	GRET	SVC	11/18/2023	1967	RET ABN	UG-SERVICE
40469555	GRET	SVC	7/26/2022	1967	RET ABN	UG-SERVICE
36078166	GRET	SVC	3/2/2020	1967	RET ABN	UG-SERVICE
41324411	GRET	SVC	3/1/2023	1967	RET ABN	UG-SERVICE
40691857	GRET	SVC	9/16/2022	1967	RET ABN	UG-SERVICE
36122365	GRET	SVC	11/5/2020	1967	RET ABN	UG-SERVICE
41407817	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
38206545	GRET	SVC	3/19/2021	1967	RET ABN	UG-SERVICE
41144028	GRET	SVC	1/11/2023	1967	RET ABN	UG-SERVICE
39998576	GRET	SVC	4/12/2022	1967	RET ABN	UG-SERVICE
43318491	GRET	SVC	8/9/2024	1967	RET ABN	UG-SERVICE
40496050	GRET	SVC	7/23/2022	1967	RET ABN	UG-SERVICE
41297878	GRET	SVC	2/21/2023	1967	RET ABN	UG-SERVICE
41307330	GRET	SVC	3/29/2023	1967	RET ABN	UG-SERVICE
40973101	GRET	SVC	12/12/2022	1967	RET ABN	UG-SERVICE
39665098	GRET	SVC	1/5/2022	1967	RET ABN	UG-SERVICE
36672714	GRET	SVC	7/18/2020	1967	RET ABN	UG-SERVICE
38541493	GRET	SVC	6/5/2021	1967	RET ABN	UG-SERVICE
40471339	GRET	SVC	7/23/2022	1967	RET ABN	UG-SERVICE
39971688	GRET	SVC	4/7/2022	1967	RET ABN	UG-SERVICE
39971299	GRET	SVC	4/18/2022	1967	RET ABN	UG-SERVICE
41534176	GRET	SVC	4/27/2023	1967	RET ABN	UG-SERVICE
39914955	GRET	SVC	3/31/2022	1967	RET ABN	UG-SERVICE
42161243	GRET	SVC	10/2/2023	1967	RET ABN	UG-SERVICE
39520336	GRET	SVC	12/10/2021	1967	RET ABN	UG-SERVICE
39576513	GRET	SVC	12/27/2021	1967	RET ABN	UG-SERVICE
38910763	GRET	SVC	8/16/2021	1967	RET ABN	UG-SERVICE
36422233	GRET	SVC	6/26/2020	1967	RET ABN	UG-SERVICE
43084020	GRET	SVC	7/30/2024	1967	RET ABN	UG-SERVICE
37525669	GRET	SVC	11/9/2020	1967	RET ABN	UG-SERVICE
42750555	GRET	SVC	2/20/2024	1967	RET ABN	UG-SERVICE
40091166	GRET	SVC	5/2/2022	1967	RET ABN	UG-SERVICE
41323426	GRET	SVC	2/28/2023	1967	RET ABN	UG-SERVICE
42925448	GRET	SVC	4/16/2024	1967	RET ABN	UG-SERVICE
41052705	GRET	SVC	1/12/2023	1967	RET ABN	UG-SERVICE
43869026	GRET	SVC	11/25/2024	1967	RET ABN	UG-SERVICE
36345887	GRET	SVC	5/13/2020	1967	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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41143510	GRET	SVC	7/31/2023	1967	RET ABN	UG-SERVICE
42023624	GRET	SVC	8/22/2023	1967	RET ABN	UG-SERVICE
43134071	GRET	SVC	6/8/2024	1967	RET ABN	UG-SERVICE
40685461	GRET	SVC	9/24/2022	1967	RET ABN	UG-SERVICE
43596416	GRET	SVC	9/18/2024	1967	RET ABN	UG-SERVICE
41719026	GRET	SVC	6/6/2023	1967	RET ABN	UG-SERVICE
41194829	GRET	SVC	1/22/2023	1967	RET ABN	UG-SERVICE
43919197	GRET	SVC	12/23/2024	1967	RET ABN	UG-SERVICE
40425791	GRET	SVC	7/11/2022	1967	RET ABN	UG-SERVICE
42205157	GRET	SVC	10/13/2023	1967	RET ABN	UG-SERVICE
36715856	GRET	SVC	9/30/2020	1967	RET ABN	UG-SERVICE
41407487	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
38265300	GRET	SVC	3/24/2021	1967	RET ABN	UG-SERVICE
43476336	GRET	SVC	8/15/2024	1967	RET ABN	UG-SERVICE
43892478	GRET	SVC	12/6/2024	1967	RET ABN	UG-SERVICE
41318153	GRET	SVC	3/2/2023	1967	RET ABN	UG-SERVICE
41052704	GRET	SVC	1/12/2023	1967	RET ABN	UG-SERVICE
39437495	GRET	SVC	11/19/2021	1967	RET ABN	UG-SERVICE
37415212	GRET	SVC	11/11/2020	1967	RET ABN	UG-SERVICE
36142352	GRET	SVC	3/17/2020	1967	RET ABN	UG-SERVICE
38012930	GRET	SVC	1/13/2021	1967	RET ABN	UG-SERVICE
43343955	GRET	SVC	7/30/2024	1967	RET ABN	UG-SERVICE
41194824	GRET	SVC	1/21/2023	1967	RET ABN	UG-SERVICE
40962280	GRET	SVC	11/21/2022	1967	RET ABN	UG-SERVICE
39331817	GRET	SVC	10/23/2021	1967	RET ABN	UG-SERVICE
41728314	GRET	SVC	6/12/2023	1967	RET ABN	UG-SERVICE
38479658	GRET	SVC	5/12/2021	1967	RET ABN	UG-SERVICE
41101695	GRET	SVC	12/29/2022	1967	RET ABN	UG-SERVICE
43477194	GRET	SVC	8/20/2024	1967	RET ABN	UG-SERVICE
39935367	GRET	SVC	6/27/2022	1967	RET ABN	UG-SERVICE
39503379	GRET	SVC	12/14/2021	1967	RET ABN	UG-SERVICE
42336409	GRET	SVC	7/18/2024	1967	RET ABN	UG-SERVICE
40636489	GRET	SVC	8/29/2022	1967	RET ABN	UG-SERVICE
39621712	GRET	SVC	1/3/2022	1967	RET ABN	UG-SERVICE
38217713	GRET	SVC	3/11/2021	1967	RET ABN	UG-SERVICE
42953077	GRET	SVC	4/18/2024	1967	RET ABN	UG-SERVICE
36102276	GRET	SVC	4/23/2020	1967	RET ABN	UG-SERVICE
43063958	GRET	SVC	5/13/2024	1967	RET ABN	UG-SERVICE
38955711	GRET	SVC	8/24/2021	1967	RET ABN	UG-SERVICE
40522528	GRET	SVC	8/4/2022	1967	RET ABN	UG-SERVICE
36240479	GRET	SVC	6/1/2020	1967	RET ABN	UG-SERVICE
36095277	GRET	SVC	3/6/2020	1967	RET ABN	UG-SERVICE
37896726	GRET	SVC	12/9/2020	1967	RET ABN	UG-SERVICE
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39831011	GRET	SVC	7/27/2020	1967	RET ABN	UG-SERVICE
43236421	GRET	SVC	6/28/2024	1967	RET ABN	UG-SERVICE
40771417	GRET	SVC	10/4/2022	1967	RET ABN	UG-SERVICE
36153162	GRET	SVC	8/17/2020	1967	RET ABN	UG-SERVICE
41409258	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
43795188	GRET	SVC	11/8/2024	1967	RET ABN	UG-SERVICE
40478176	GRET	SVC	7/27/2022	1967	RET ABN	UG-SERVICE
38571058	GRET	SVC	6/11/2021	1967	RET ABN	UG-SERVICE
37035951	GRET	SVC	10/8/2020	1967	RET ABN	UG-SERVICE
40237837	GRET	SVC	6/1/2022	1967	RET ABN	UG-SERVICE
40729723	GRET	SVC	9/27/2022	1967	RET ABN	UG-SERVICE
42487579	GRET	SVC	7/18/2024	1967	RET ABN	UG-SERVICE
42534645	GRET	SVC	1/8/2024	1967	RET ABN	UG-SERVICE
43746369	GRET	SVC	10/28/2024	1967	RET ABN	UG-SERVICE
42097609	GRET	SVC	11/27/2023	1967	RET ABN	UG-SERVICE
36927420	GRET	SVC	9/16/2020	1967	RET ABN	UG-SERVICE
42145313	GRET	SVC	9/8/2023	1967	RET ABN	UG-SERVICE
40976611	GRET	SVC	11/23/2022	1967	RET ABN	UG-SERVICE
42995767	GRET	SVC	4/29/2024	1967	RET ABN	UG-SERVICE
39388230	GRET	SVC	11/4/2021	1967	RET ABN	UG-SERVICE
39371727	GRET	SVC	11/2/2021	1967	RET ABN	UG-SERVICE
38150614	GRET	SVC	2/22/2021	1967	RET ABN	UG-SERVICE
41577519	GRET	SVC	5/3/2023	1967	RET ABN	UG-SERVICE
41035391	GRET	SVC	12/15/2022	1967	RET ABN	UG-SERVICE
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43177756	GRET	SVC	6/13/2024	1967	RET ABN	UG-SERVICE
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41411190	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
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41143575	GRET	SVC	4/26/2023	1967	RET ABN	UG-SERVICE
42813116	GRET	SVC	3/11/2024	1967	RET ABN	UG-SERVICE
36779223	GRET	SVC	9/8/2020	1967	RET ABN	UG-SERVICE
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41407486	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
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41410858	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
43610002	GRET	SVC	10/16/2024	1967	RET ABN	UG-SERVICE
41321851	GRET	SVC	3/9/2023	1967	RET ABN	UG-SERVICE
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39424071	GRET	SVC	6/27/2022	1967	RET ABN	UG-SERVICE
41424037	GRET	SVC	10/18/2023	1967	RET ABN	UG-SERVICE
37146547	GRET	SVC	12/7/2020	1967	RET ABN	UG-SERVICE
43403341	GRET	SVC	8/12/2024	1967	RET ABN	UG-SERVICE
43116813	GRET	SVC	6/13/2024	1967	RET ABN	UG-SERVICE
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37415099	GRET	SVC	11/11/2020	1967	RET ABN	UG-SERVICE
39666485	GRET	SVC	11/18/2022	1967	RET ABN	UG-SERVICE
43854347	GRET	SVC	11/22/2024	1967	RET ABN	UG-SERVICE
39666047	GRET	SVC	8/3/2022	1967	RET ABN	UG-SERVICE
35928748	GRET	SVC	1/21/2020	1967	RET ABN	UG-SERVICE
41411425	GRET	SVC	11/2/2023	1967	RET ABN	UG-SERVICE
38076254	GRET	SVC	2/16/2021	1967	RET ABN	UG-SERVICE
36203943	GRET	SVC	4/22/2020	1967	RET ABN	UG-SERVICE
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38749018	GRET	SVC	7/15/2021	1967	RET ABN	UG-SERVICE
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42247685	GRET	SVC	9/7/2023	1967	RET ABN	UG-SERVICE
41185862	GRET	SVC	1/20/2023	1967	RET ABN	UG-SERVICE
38486936	GRET	SVC	5/13/2021	1967	RET ABN	UG-SERVICE
36931800	GRET	SVC	9/15/2020	1967	RET ABN	UG-SERVICE
36153979	GRET	SVC	7/20/2020	1967	RET ABN	UG-SERVICE
41409111	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
41327517	GRET	SVC	2/15/2023	1967	RET ABN	UG-SERVICE
41503656	GRET	SVC	4/17/2023	1967	RET ABN	UG-SERVICE
38382521	GRET	SVC	4/22/2021	1967	RET ABN	UG-SERVICE
42894876	GRET	SVC	11/19/2024	1967	RET ABN	UG-SERVICE
41143711	GRET	SVC	7/31/2023	1967	RET ABN	UG-SERVICE
36137855	GRET	SVC	4/20/2020	1967	RET ABN	UG-SERVICE
38660377	GRET	SVC	6/24/2021	1967	RET ABN	UG-SERVICE
36214579	GRET	SVC	4/30/2020	1967	RET ABN	UG-SERVICE
41330184	GRET	SVC	3/1/2023	1967	RET ABN	UG-SERVICE
43642438	GRET	SVC	10/4/2024	1967	RET ABN	UG-SERVICE
40537458	GRET	SVC	8/10/2022	1967	RET ABN	UG-SERVICE
38242131	GRET	SVC	3/16/2021	1967	RET ABN	UG-SERVICE
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43365791	GRET	SVC	11/7/2024	1967	RET ABN	UG-SERVICE
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36278024	GRET	SVC	6/11/2020	1967	RET ABN	UG-SERVICE
41903924	GRET	SVC	11/3/2023	1967	RET ABN	UG-SERVICE
36750482	GRET	SVC	9/14/2020	1967	RET ABN	UG-SERVICE
39831378	GRET	SVC	8/3/2022	1967	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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36022114	GRET	SVC	2/18/2020	1967	RET ABN	UG-SERVICE
36342128	GRET	SVC	12/23/2020	1967	RET ABN	UG-SERVICE
36269698	GRET	SVC	4/27/2020	1967	RET ABN	UG-SERVICE
36304097	GRET	SVC	4/23/2020	1967	RET ABN	UG-SERVICE
42124244	GRET	SVC	9/19/2023	1967	RET ABN	UG-SERVICE
43757513	GRET	SVC	10/28/2024	1967	RET ABN	UG-SERVICE
40231470	GRET	SVC	5/31/2022	1967	RET ABN	UG-SERVICE
40524324	GRET	SVC	8/3/2022	1967	RET ABN	UG-SERVICE
36817871	GRET	SVC	9/2/2020	1967	RET ABN	UG-SERVICE
39370519	GRET	SVC	11/1/2021	1967	RET ABN	UG-SERVICE
37030982	GRET	SVC	10/9/2020	1967	RET ABN	UG-SERVICE
41675753	GRET	SVC	5/31/2023	1967	RET ABN	UG-SERVICE
41594980	GRET	SVC	5/2/2023	1967	RET ABN	UG-SERVICE
38052185	GRET	SVC	1/27/2021	1967	RET ABN	UG-SERVICE
43628685	GRET	SVC	9/30/2024	1967	RET ABN	UG-SERVICE
43112167	GRET	SVC	5/29/2024	1967	RET ABN	UG-SERVICE
42405621	GRET	SVC	11/22/2023	1967	RET ABN	UG-SERVICE
40536285	GRET	SVC	8/18/2022	1967	RET ABN	UG-SERVICE
41052712	GRET	SVC	1/12/2023	1967	RET ABN	UG-SERVICE
36138366	GRET	SVC	4/23/2020	1967	RET ABN	UG-SERVICE
36091940	GRET	SVC	10/30/2020	1967	RET ABN	UG-SERVICE
41411775	GRET	SVC	4/2/2024	1967	RET ABN	UG-SERVICE
41083734	GRET	SVC	12/22/2022	1967	RET ABN	UG-SERVICE
41306994	GRET	SVC	2/20/2023	1967	RET ABN	UG-SERVICE
41084268	GRET	SVC	1/11/2023	1967	RET ABN	UG-SERVICE
42216807	GRET	SVC	12/6/2023	1968	RET ABN	UG-SERVICE
40858841	GRET	SVC	10/27/2022	1968	RET ABN	UG-SERVICE
40985081	GRET	SVC	11/14/2022	1968	RET ABN	UG-SERVICE
39831465	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
42036340	GRET	SVC	9/11/2023	1968	RET ABN	UG-SERVICE
39554488	GRET	SVC	12/23/2021	1968	RET ABN	UG-SERVICE
36121681	GRET	SVC	10/12/2020	1968	RET ABN	UG-SERVICE
43669442	GRET	SVC	10/9/2024	1968	RET ABN	UG-SERVICE
38165515	GRET	SVC	2/23/2021	1968	RET ABN	UG-SERVICE
42542323	GRET	SVC	1/25/2024	1968	RET ABN	UG-SERVICE
41920619	GRET	SVC	7/31/2023	1968	RET ABN	UG-SERVICE
40395535	GRET	SVC	7/6/2022	1968	RET ABN	UG-SERVICE
40301513	GRET	SVC	6/16/2022	1968	RET ABN	UG-SERVICE
36951735	GRET	SVC	9/17/2020	1968	RET ABN	UG-SERVICE
40203722	GRET	SVC	5/23/2022	1968	RET ABN	UG-SERVICE
42216801	GRET	SVC	12/5/2023	1968	RET ABN	UG-SERVICE
43632098	GRET	SVC	10/4/2024	1968	RET ABN	UG-SERVICE
42425465	GRET	SVC	11/30/2023	1968	RET ABN	UG-SERVICE
36120954	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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43364874	GRET	SVC	12/2/2024	1968	RET ABN	UG-SERVICE
40237978	GRET	SVC	6/2/2022	1968	RET ABN	UG-SERVICE
43365795	GRET	SVC	10/30/2024	1968	RET ABN	UG-SERVICE
38373630	GRET	SVC	4/14/2021	1968	RET ABN	UG-SERVICE
42520394	GRET	SVC	1/25/2024	1968	RET ABN	UG-SERVICE
38589148	GRET	SVC	10/5/2021	1968	RET ABN	UG-SERVICE
43610586	GRET	SVC	11/21/2024	1968	RET ABN	UG-SERVICE
33866282	GRET	SVC	10/16/2021	1968	RET ABN	UG-SERVICE
36611386	GRET	SVC	7/16/2020	1968	RET ABN	UG-SERVICE
36122580	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE
41697783	GRET	SVC	6/2/2023	1968	RET ABN	UG-SERVICE
42841037	GRET	SVC	3/19/2024	1968	RET ABN	UG-SERVICE
39935477	GRET	SVC	6/24/2022	1968	RET ABN	UG-SERVICE
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36048860	GRET	SVC	2/26/2020	1968	RET ABN	UG-SERVICE
43481195	GRET	SVC	10/23/2024	1968	RET ABN	UG-SERVICE
37149310	GRET	SVC	10/31/2020	1968	RET ABN	UG-SERVICE
41429991	GRET	SVC	9/12/2023	1968	RET ABN	UG-SERVICE
39554486	GRET	SVC	12/23/2021	1968	RET ABN	UG-SERVICE
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39367962	GRET	SVC	11/4/2021	1968	RET ABN	UG-SERVICE
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38594108	GRET	SVC	9/9/2021	1968	RET ABN	UG-SERVICE
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43610588	GRET	SVC	12/11/2024	1968	RET ABN	UG-SERVICE
40669808	GRET	SVC	10/4/2022	1968	RET ABN	UG-SERVICE
36613098	GRET	SVC	7/11/2020	1968	RET ABN	UG-SERVICE
42450330	GRET	SVC	12/2/2023	1968	RET ABN	UG-SERVICE
41318143	GRET	SVC	3/2/2023	1968	RET ABN	UG-SERVICE
42427950	GRET	SVC	11/30/2023	1968	RET ABN	UG-SERVICE
36107003	GRET	SVC	4/24/2020	1968	RET ABN	UG-SERVICE
38608782	GRET	SVC	12/23/2021	1968	RET ABN	UG-SERVICE
39423116	GRET	SVC	6/27/2022	1968	RET ABN	UG-SERVICE
42564472	GRET	SVC	1/10/2024	1968	RET ABN	UG-SERVICE
36396246	GRET	SVC	6/2/2020	1968	RET ABN	UG-SERVICE
36613097	GRET	SVC	7/11/2020	1968	RET ABN	UG-SERVICE
42622530	GRET	SVC	2/12/2024	1968	RET ABN	UG-SERVICE
41088836	GRET	SVC	1/13/2023	1968	RET ABN	UG-SERVICE
36345899	GRET	SVC	5/20/2020	1968	RET ABN	UG-SERVICE
42774105	GRET	SVC	2/26/2024	1968	RET ABN	UG-SERVICE
38588933	GRET	SVC	9/29/2021	1968	RET ABN	UG-SERVICE
41074934	GRET	SVC	12/19/2022	1968	RET ABN	UG-SERVICE
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order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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42833341	GRET	SVC	7/22/2024	1968	RET ABN	UG-SERVICE
41411827	GRET	SVC	4/2/2024	1968	RET ABN	UG-SERVICE
43586515	GRET	SVC	9/9/2024	1968	RET ABN	UG-SERVICE
38589321	GRET	SVC	8/3/2021	1968	RET ABN	UG-SERVICE
41572927	GRET	SVC	6/10/2024	1968	RET ABN	UG-SERVICE
38642560	GRET	SVC	6/29/2021	1968	RET ABN	UG-SERVICE
37811156	GRET	SVC	12/4/2020	1968	RET ABN	UG-SERVICE
43524136	GRET	SVC	10/15/2024	1968	RET ABN	UG-SERVICE
39665953	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
36749021	GRET	SVC	8/17/2020	1968	RET ABN	UG-SERVICE
36613382	GRET	SVC	7/10/2020	1968	RET ABN	UG-SERVICE
39666145	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
42575791	GRET	SVC	1/13/2024	1968	RET ABN	UG-SERVICE
36241112	GRET	SVC	5/5/2020	1968	RET ABN	UG-SERVICE
41969542	GRET	SVC	8/1/2024	1968	RET ABN	UG-SERVICE
40126087	GRET	SVC	5/5/2022	1968	RET ABN	UG-SERVICE
40985080	GRET	SVC	11/14/2022	1968	RET ABN	UG-SERVICE
42050868	GRET	SVC	8/30/2023	1968	RET ABN	UG-SERVICE
39666056	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
36137881	GRET	SVC	4/22/2020	1968	RET ABN	UG-SERVICE
40802552	GRET	SVC	10/6/2022	1968	RET ABN	UG-SERVICE
43623499	GRET	SVC	12/3/2024	1968	RET ABN	UG-SERVICE
41922423	GRET	SVC	7/31/2023	1968	RET ABN	UG-SERVICE
41817953	GRET	SVC	6/26/2023	1968	RET ABN	UG-SERVICE
36613084	GRET	SVC	7/14/2020	1968	RET ABN	UG-SERVICE
42336406	GRET	SVC	7/18/2024	1968	RET ABN	UG-SERVICE
42833094	GRET	SVC	7/22/2024	1968	RET ABN	UG-SERVICE
43481193	GRET	SVC	10/22/2024	1968	RET ABN	UG-SERVICE
43493942	GRET	SVC	8/29/2024	1968	RET ABN	UG-SERVICE
39665954	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
36486231	GRET	SVC	6/25/2020	1968	RET ABN	UG-SERVICE
39666099	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
38991541	GRET	SVC	8/22/2021	1968	RET ABN	UG-SERVICE
40615036	GRET	SVC	8/22/2022	1968	RET ABN	UG-SERVICE
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43365798	GRET	SVC	10/9/2024	1968	RET ABN	UG-SERVICE
40024220	GRET	SVC	4/18/2022	1968	RET ABN	UG-SERVICE
39666097	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
40114951	GRET	SVC	5/4/2022	1968	RET ABN	UG-SERVICE
36612857	GRET	SVC	7/14/2020	1968	RET ABN	UG-SERVICE
39831563	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
41411483	GRET	SVC	11/2/2023	1968	RET ABN	UG-SERVICE
43371533	GRET	SVC	7/29/2024	1968	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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43642855	GRET	SVC	10/1/2024	1968	RET ABN	UG-SERVICE
41158181	GRET	SVC	1/10/2023	1968	RET ABN	UG-SERVICE
38479663	GRET	SVC	5/12/2021	1968	RET ABN	UG-SERVICE
36966510	GRET	SVC	9/22/2020	1968	RET ABN	UG-SERVICE
36544029	GRET	SVC	7/26/2020	1968	RET ABN	UG-SERVICE
36893331	GRET	SVC	9/14/2020	1968	RET ABN	UG-SERVICE
43581817	GRET	SVC	9/19/2024	1968	RET ABN	UG-SERVICE
39666045	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
39423748	GRET	SVC	6/27/2022	1968	RET ABN	UG-SERVICE
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39543432	GRET	SVC	12/14/2021	1968	RET ABN	UG-SERVICE
41913822	GRET	SVC	7/31/2023	1968	RET ABN	UG-SERVICE
41654468	GRET	SVC	5/18/2023	1968	RET ABN	UG-SERVICE
40577998	GRET	SVC	8/15/2022	1968	RET ABN	UG-SERVICE
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43365687	GRET	SVC	12/3/2024	1968	RET ABN	UG-SERVICE
42219601	GRET	SVC	10/11/2023	1968	RET ABN	UG-SERVICE
39417345	GRET	SVC	11/15/2021	1968	RET ABN	UG-SERVICE
41165474	GRET	SVC	1/17/2023	1968	RET ABN	UG-SERVICE
37943019	GRET	SVC	12/23/2020	1968	RET ABN	UG-SERVICE
41180518	GRET	SVC	1/20/2023	1968	RET ABN	UG-SERVICE
39666040	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
41969499	GRET	SVC	8/1/2024	1968	RET ABN	UG-SERVICE
41807875	GRET	SVC	6/27/2023	1968	RET ABN	UG-SERVICE
37741359	GRET	SVC	11/25/2020	1968	RET ABN	UG-SERVICE
43543033	GRET	SVC	10/4/2024	1968	RET ABN	UG-SERVICE
42207904	GRET	SVC	6/19/2024	1968	RET ABN	UG-SERVICE
39114628	GRET	SVC	9/27/2021	1968	RET ABN	UG-SERVICE
39666050	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
40886920	GRET	SVC	10/27/2022	1968	RET ABN	UG-SERVICE
36121099	GRET	SVC	10/16/2020	1968	RET ABN	UG-SERVICE
38885601	GRET	SVC	9/2/2021	1968	RET ABN	UG-SERVICE
39906692	GRET	SVC	3/21/2022	1968	RET ABN	UG-SERVICE
42670281	GRET	SVC	9/19/2024	1968	RET ABN	UG-SERVICE
43443557	GRET	SVC	8/19/2024	1968	RET ABN	UG-SERVICE
41834506	GRET	SVC	7/21/2023	1968	RET ABN	UG-SERVICE
39665941	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
41469768	GRET	SVC	4/5/2023	1968	RET ABN	UG-SERVICE
36113086	GRET	SVC	10/12/2020	1968	RET ABN	UG-SERVICE
38512266	GRET	SVC	5/20/2021	1968	RET ABN	UG-SERVICE
42803974	GRET	SVC	3/15/2024	1968	RET ABN	UG-SERVICE
39665943	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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41844783	GRET	SVC	7/24/2023	1968	RET ABN	UG-SERVICE
39831467	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
38213089	GRET	SVC	3/11/2021	1968	RET ABN	UG-SERVICE
41316670	GRET	SVC	3/6/2023	1968	RET ABN	UG-SERVICE
42833351	GRET	SVC	7/23/2024	1968	RET ABN	UG-SERVICE
37994208	GRET	SVC	1/11/2021	1968	RET ABN	UG-SERVICE
38819878	GRET	SVC	8/2/2021	1968	RET ABN	UG-SERVICE
38732091	GRET	SVC	7/7/2021	1968	RET ABN	UG-SERVICE
41318463	GRET	SVC	3/6/2023	1968	RET ABN	UG-SERVICE
43749346	GRET	SVC	10/28/2024	1968	RET ABN	UG-SERVICE
38284395	GRET	SVC	3/29/2021	1968	RET ABN	UG-SERVICE
36119808	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE
39524063	GRET	SVC	12/11/2021	1968	RET ABN	UG-SERVICE
41452960	GRET	SVC	10/25/2023	1968	RET ABN	UG-SERVICE
40604652	GRET	SVC	8/24/2022	1968	RET ABN	UG-SERVICE
36122582	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE
43547204	GRET	SVC	9/11/2024	1968	RET ABN	UG-SERVICE
41429992	GRET	SVC	9/13/2023	1968	RET ABN	UG-SERVICE
42027511	GRET	SVC	8/28/2023	1968	RET ABN	UG-SERVICE
38593808	GRET	SVC	8/18/2021	1968	RET ABN	UG-SERVICE
39665723	GRET	SVC	1/5/2022	1968	RET ABN	UG-SERVICE
38353012	GRET	SVC	2/17/2023	1968	RET ABN	UG-SERVICE
43489848	GRET	SVC	8/26/2024	1968	RET ABN	UG-SERVICE
40189505	GRET	SVC	5/27/2022	1968	RET ABN	UG-SERVICE
36172660	GRET	SVC	2/12/2020	1968	RET ABN	UG-SERVICE
36119903	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE
43648966	GRET	SVC	12/5/2024	1968	RET ABN	UG-SERVICE
36613099	GRET	SVC	7/10/2020	1968	RET ABN	UG-SERVICE
41353367	GRET	SVC	3/9/2023	1968	RET ABN	UG-SERVICE
43675735	GRET	SVC	10/16/2024	1968	RET ABN	UG-SERVICE
36107018	GRET	SVC	4/22/2020	1968	RET ABN	UG-SERVICE
41572958	GRET	SVC	5/1/2023	1968	RET ABN	UG-SERVICE
42551425	GRET	SVC	1/9/2024	1968	RET ABN	UG-SERVICE
39292643	GRET	SVC	10/15/2021	1968	RET ABN	UG-SERVICE
41965714	GRET	SVC	8/7/2023	1968	RET ABN	UG-SERVICE
41965641	GRET	SVC	7/26/2023	1968	RET ABN	UG-SERVICE
36613394	GRET	SVC	7/10/2020	1968	RET ABN	UG-SERVICE
43677914	GRET	SVC	10/18/2024	1968	RET ABN	UG-SERVICE
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41485246	GRET	SVC	3/24/2023	1968	RET ABN	UG-SERVICE
40948343	GRET	SVC	11/21/2022	1968	RET ABN	UG-SERVICE
38793786	GRET	SVC	7/20/2021	1968	RET ABN	UG-SERVICE
39424066	GRET	SVC	6/27/2022	1968	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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39830446	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
36613389	GRET	SVC	7/8/2020	1968	RET ABN	UG-SERVICE
42135353	GRET	SVC	9/6/2023	1968	RET ABN	UG-SERVICE
38593157	GRET	SVC	10/26/2021	1968	RET ABN	UG-SERVICE
43484868	GRET	SVC	8/26/2024	1968	RET ABN	UG-SERVICE
38677200	GRET	SVC	6/24/2021	1968	RET ABN	UG-SERVICE
43223748	GRET	SVC	6/13/2024	1968	RET ABN	UG-SERVICE
38268742	GRET	SVC	10/20/2021	1968	RET ABN	UG-SERVICE
43141082	GRET	SVC	6/5/2024	1968	RET ABN	UG-SERVICE
38589154	GRET	SVC	10/27/2021	1968	RET ABN	UG-SERVICE
36649706	GRET	SVC	7/20/2020	1968	RET ABN	UG-SERVICE
43503585	GRET	SVC	8/28/2024	1968	RET ABN	UG-SERVICE
42216808	GRET	SVC	12/6/2023	1968	RET ABN	UG-SERVICE
38720230	GRET	SVC	7/16/2021	1968	RET ABN	UG-SERVICE
41407558	GRET	SVC	4/2/2024	1968	RET ABN	UG-SERVICE
39666042	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
41699621	GRET	SVC	6/1/2023	1968	RET ABN	UG-SERVICE
43732057	GRET	SVC	12/11/2024	1968	RET ABN	UG-SERVICE
36419429	GRET	SVC	6/8/2020	1968	RET ABN	UG-SERVICE
43490540	GRET	SVC	8/22/2024	1968	RET ABN	UG-SERVICE
40830319	GRET	SVC	9/8/2022	1968	RET ABN	UG-SERVICE
39423202	GRET	SVC	11/8/2021	1968	RET ABN	UG-SERVICE
43028509	GRET	SVC	8/1/2024	1968	RET ABN	UG-SERVICE
42136772	GRET	SVC	9/20/2023	1968	RET ABN	UG-SERVICE
39376581	GRET	SVC	3/22/2022	1968	RET ABN	UG-SERVICE
38417926	GRET	SVC	5/11/2021	1968	RET ABN	UG-SERVICE
38593804	GRET	SVC	10/7/2021	1968	RET ABN	UG-SERVICE
41245804	GRET	SVC	2/10/2023	1968	RET ABN	UG-SERVICE
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39863321	GRET	SVC	1/25/2022	1968	RET ABN	UG-SERVICE
41472415	GRET	SVC	9/1/2023	1968	RET ABN	UG-SERVICE
39508225	GRET	SVC	11/21/2021	1968	RET ABN	UG-SERVICE
39619116	GRET	SVC	1/3/2022	1968	RET ABN	UG-SERVICE
39921034	GRET	SVC	3/21/2022	1968	RET ABN	UG-SERVICE
38589200	GRET	SVC	10/1/2021	1968	RET ABN	UG-SERVICE
38589159	GRET	SVC	9/9/2021	1968	RET ABN	UG-SERVICE
39423746	GRET	SVC	6/27/2022	1968	RET ABN	UG-SERVICE
41273846	GRET	SVC	2/14/2023	1968	RET ABN	UG-SERVICE
42012218	GRET	SVC	8/18/2023	1968	RET ABN	UG-SERVICE
36673187	GRET	SVC	7/20/2020	1968	RET ABN	UG-SERVICE
38608389	GRET	SVC	8/9/2021	1968	RET ABN	UG-SERVICE
39956345	GRET	SVC	4/11/2022	1968	RET ABN	UG-SERVICE
39554487	GRET	SVC	12/23/2021	1968	RET ABN	UG-SERVICE
36121008	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
37116189	GRET	SVC	10/29/2020	1968	RET ABN	UG-SERVICE
39554489	GRET	SVC	12/23/2021	1968	RET ABN	UG-SERVICE
43837910	GRET	SVC	11/21/2024	1968	RET ABN	UG-SERVICE
39532682	GRET	SVC	12/13/2021	1968	RET ABN	UG-SERVICE
39665940	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
40207181	GRET	SVC	6/2/2022	1968	RET ABN	UG-SERVICE
43179538	GRET	SVC	5/30/2024	1968	RET ABN	UG-SERVICE
39666051	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
36157809	GRET	SVC	3/24/2020	1968	RET ABN	UG-SERVICE
39666059	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
36485742	GRET	SVC	6/24/2020	1968	RET ABN	UG-SERVICE
42419710	GRET	SVC	12/6/2023	1968	RET ABN	UG-SERVICE
38589146	GRET	SVC	10/5/2021	1968	RET ABN	UG-SERVICE
41454523	GRET	SVC	2/20/2023	1968	RET ABN	UG-SERVICE
40768323	GRET	SVC	11/1/2022	1968	RET ABN	UG-SERVICE
39740639	GRET	SVC	2/14/2022	1968	RET ABN	UG-SERVICE
40707705	GRET	SVC	9/24/2022	1968	RET ABN	UG-SERVICE
40738247	GRET	SVC	9/28/2022	1968	RET ABN	UG-SERVICE
39665950	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
39809494	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
36119904	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE
36153651	GRET	SVC	7/15/2020	1968	RET ABN	UG-SERVICE
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38655449	GRET	SVC	6/24/2021	1968	RET ABN	UG-SERVICE
36120704	GRET	SVC	10/30/2020	1968	RET ABN	UG-SERVICE
39666057	GRET	SVC	8/3/2022	1968	RET ABN	UG-SERVICE
41082945	GRET	SVC	12/21/2022	1968	RET ABN	UG-SERVICE
40724354	GRET	SVC	9/21/2022	1968	RET ABN	UG-SERVICE
41760939	GRET	SVC	6/24/2023	1968	RET ABN	UG-SERVICE
41411143	GRET	SVC	4/2/2024	1968	RET ABN	UG-SERVICE
42812054	GRET	SVC	3/26/2024	1968	RET ABN	UG-SERVICE
38589317	GRET	SVC	11/2/2021	1968	RET ABN	UG-SERVICE
42247377	GRET	SVC	10/16/2023	1968	RET ABN	UG-SERVICE
36609968	GRET	SVC	7/8/2020	1968	RET ABN	UG-SERVICE
43366068	GRET	SVC	10/29/2024	1968	RET ABN	UG-SERVICE
43648970	GRET	SVC	12/6/2024	1968	RET ABN	UG-SERVICE
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40868725	GRET	SVC	10/27/2022	1968	RET ABN	UG-SERVICE
43616973	GRET	SVC	10/14/2024	1968	RET ABN	UG-SERVICE
36750113	GRET	SVC	8/17/2020	1968	RET ABN	UG-SERVICE
38676978	GRET	SVC	6/20/2021	1968	RET ABN	UG-SERVICE
38593811	GRET	SVC	8/19/2021	1968	RET ABN	UG-SERVICE
39424072	GRET	SVC	6/27/2022	1968	RET ABN	UG-SERVICE
42498209	GRET	SVC	12/20/2023	1968	RET ABN	UG-SERVICE
36108032	GRET	SVC	3/10/2020	1968	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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43362654	GRET	SVC	8/9/2024	1968	RET ABN	UG-SERVICE
41424185	GRET	SVC	10/18/2023	1968	RET ABN	UG-SERVICE
41779584	GRET	SVC	6/23/2023	1968	RET ABN	UG-SERVICE
38593156	GRET	SVC	11/3/2021	1968	RET ABN	UG-SERVICE
39346037	GRET	SVC	11/2/2021	1969	RET ABN	UG-SERVICE
42135426	GRET	SVC	9/21/2023	1969	RET ABN	UG-SERVICE
38987685	GRET	SVC	8/24/2021	1969	RET ABN	UG-SERVICE
43318346	GRET	SVC	7/17/2024	1969	RET ABN	UG-SERVICE
40526784	GRET	SVC	8/9/2022	1969	RET ABN	UG-SERVICE
39665666	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
43760796	GRET	SVC	10/29/2024	1969	RET ABN	UG-SERVICE
39657778	GRET	SVC	2/9/2022	1969	RET ABN	UG-SERVICE
42216598	GRET	SVC	12/5/2023	1969	RET ABN	UG-SERVICE
38379359	GRET	SVC	8/2/2021	1969	RET ABN	UG-SERVICE
38200599	GRET	SVC	3/12/2021	1969	RET ABN	UG-SERVICE
36885293	GRET	SVC	10/15/2020	1969	RET ABN	UG-SERVICE
39665271	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
36396224	GRET	SVC	6/3/2020	1969	RET ABN	UG-SERVICE
36314386	GRET	SVC	5/11/2020	1969	RET ABN	UG-SERVICE
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35934605	GRET	SVC	1/10/2020	1969	RET ABN	UG-SERVICE
39830404	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
43477846	GRET	SVC	9/5/2024	1969	RET ABN	UG-SERVICE
42014810	GRET	SVC	8/21/2023	1969	RET ABN	UG-SERVICE
41303790	GRET	SVC	2/23/2023	1969	RET ABN	UG-SERVICE
42834157	GRET	SVC	8/12/2024	1969	RET ABN	UG-SERVICE
39831568	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
43610471	GRET	SVC	9/23/2024	1969	RET ABN	UG-SERVICE
40354414	GRET	SVC	6/25/2022	1969	RET ABN	UG-SERVICE
39830441	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
37122616	GRET	SVC	10/28/2020	1969	RET ABN	UG-SERVICE
38394494	GRET	SVC	5/10/2021	1969	RET ABN	UG-SERVICE
40561834	GRET	SVC	8/10/2022	1969	RET ABN	UG-SERVICE
41242617	GRET	SVC	3/24/2023	1969	RET ABN	UG-SERVICE
42833774	GRET	SVC	7/22/2024	1969	RET ABN	UG-SERVICE
41408295	GRET	SVC	4/2/2024	1969	RET ABN	UG-SERVICE
39421588	GRET	SVC	11/7/2021	1969	RET ABN	UG-SERVICE
38967762	GRET	SVC	9/1/2021	1969	RET ABN	UG-SERVICE
38942478	GRET	SVC	8/22/2021	1969	RET ABN	UG-SERVICE
39041591	GRET	SVC	8/31/2021	1969	RET ABN	UG-SERVICE
42666380	GRET	SVC	2/16/2024	1969	RET ABN	UG-SERVICE
39522259	GRET	SVC	12/13/2021	1969	RET ABN	UG-SERVICE
43320398	GRET	SVC	7/18/2024	1969	RET ABN	UG-SERVICE
39389661	GRET	SVC	11/23/2021	1969	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42386658	GRET	SVC	11/20/2023	1969	RET ABN	UG-SERVICE
43904972	GRET	SVC	12/9/2024	1969	RET ABN	UG-SERVICE
39741134	GRET	SVC	2/7/2022	1969	RET ABN	UG-SERVICE
40359859	GRET	SVC	6/29/2022	1969	RET ABN	UG-SERVICE
41194178	GRET	SVC	1/27/2023	1969	RET ABN	UG-SERVICE
38392184	GRET	SVC	4/19/2021	1969	RET ABN	UG-SERVICE
36260064	GRET	SVC	3/18/2020	1969	RET ABN	UG-SERVICE
38746118	GRET	SVC	7/12/2021	1969	RET ABN	UG-SERVICE
43116179	GRET	SVC	5/29/2024	1969	RET ABN	UG-SERVICE
41436457	GRET	SVC	3/30/2023	1969	RET ABN	UG-SERVICE
41323230	GRET	SVC	3/20/2023	1969	RET ABN	UG-SERVICE
41214310	GRET	SVC	1/31/2023	1969	RET ABN	UG-SERVICE
40744383	GRET	SVC	9/28/2022	1969	RET ABN	UG-SERVICE
38738847	GRET	SVC	7/12/2021	1969	RET ABN	UG-SERVICE
43064607	GRET	SVC	5/16/2024	1969	RET ABN	UG-SERVICE
39437430	GRET	SVC	11/18/2021	1969	RET ABN	UG-SERVICE
36704920	GRET	SVC	8/18/2020	1969	RET ABN	UG-SERVICE
43324306	GRET	SVC	10/18/2024	1969	RET ABN	UG-SERVICE
41914102	GRET	SVC	7/27/2023	1969	RET ABN	UG-SERVICE
37387655	GRET	SVC	11/9/2020	1969	RET ABN	UG-SERVICE
36396462	GRET	SVC	6/3/2020	1969	RET ABN	UG-SERVICE
41053076	GRET	SVC	12/15/2022	1969	RET ABN	UG-SERVICE
43258991	GRET	SVC	9/19/2024	1969	RET ABN	UG-SERVICE
39830405	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
40280048	GRET	SVC	4/27/2023	1969	RET ABN	UG-SERVICE
39665672	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
39830413	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
36591056	GRET	SVC	7/7/2020	1969	RET ABN	UG-SERVICE
36135786	GRET	SVC	4/21/2020	1969	RET ABN	UG-SERVICE
39665667	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
39350621	GRET	SVC	12/3/2021	1969	RET ABN	UG-SERVICE
39665270	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
36002346	GRET	SVC	2/11/2020	1969	RET ABN	UG-SERVICE
43013320	GRET	SVC	5/6/2024	1969	RET ABN	UG-SERVICE
40980504	GRET	SVC	11/23/2022	1969	RET ABN	UG-SERVICE
39247280	GRET	SVC	10/22/2021	1969	RET ABN	UG-SERVICE
39830440	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
35882477	GRET	SVC	1/13/2020	1969	RET ABN	UG-SERVICE
39757031	GRET	SVC	6/17/2021	1969	RET ABN	UG-SERVICE
42389810	GRET	SVC	11/20/2023	1969	RET ABN	UG-SERVICE
39665668	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
39830458	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
42564737	GRET	SVC	1/10/2024	1969	RET ABN	UG-SERVICE
43461018	GRET	SVC	8/21/2024	1969	RET ABN	UG-SERVICE
41348969	GRET	SVC	3/8/2023	1969	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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35925105	GRET	SVC	1/18/2020	1969	RET ABN	UG-SERVICE
42216812	GRET	SVC	12/6/2023	1969	RET ABN	UG-SERVICE
39274159	GRET	SVC	10/12/2021	1969	RET ABN	UG-SERVICE
40933264	GRET	SVC	11/16/2022	1969	RET ABN	UG-SERVICE
42216814	GRET	SVC	12/6/2023	1969	RET ABN	UG-SERVICE
41065454	GRET	SVC	12/13/2022	1969	RET ABN	UG-SERVICE
38314467	GRET	SVC	4/5/2021	1969	RET ABN	UG-SERVICE
36121688	GRET	SVC	10/12/2020	1969	RET ABN	UG-SERVICE
36314075	GRET	SVC	5/7/2020	1969	RET ABN	UG-SERVICE
38267999	GRET	SVC	3/20/2021	1969	RET ABN	UG-SERVICE
39654867	GRET	SVC	6/28/2022	1969	RET ABN	UG-SERVICE
42744009	GRET	SVC	2/21/2024	1969	RET ABN	UG-SERVICE
42165831	GRET	SVC	10/11/2023	1969	RET ABN	UG-SERVICE
43614043	GRET	SVC	9/23/2024	1969	RET ABN	UG-SERVICE
38413340	GRET	SVC	5/6/2021	1969	RET ABN	UG-SERVICE
36876148	GRET	SVC	9/2/2020	1969	RET ABN	UG-SERVICE
36106836	GRET	SVC	4/24/2020	1969	RET ABN	UG-SERVICE
42433001	GRET	SVC	12/6/2023	1969	RET ABN	UG-SERVICE
40469915	GRET	SVC	7/20/2022	1969	RET ABN	UG-SERVICE
39665811	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
43610593	GRET	SVC	11/21/2024	1969	RET ABN	UG-SERVICE
43610595	GRET	SVC	11/21/2024	1969	RET ABN	UG-SERVICE
36370503	GRET	SVC	5/28/2020	1969	RET ABN	UG-SERVICE
39571086	GRET	SVC	12/17/2021	1969	RET ABN	UG-SERVICE
40609436	GRET	SVC	8/24/2022	1969	RET ABN	UG-SERVICE
38607906	GRET	SVC	12/23/2021	1969	RET ABN	UG-SERVICE
38896185	GRET	SVC	8/3/2021	1969	RET ABN	UG-SERVICE
40619595	GRET	SVC	8/22/2022	1969	RET ABN	UG-SERVICE
43344390	GRET	SVC	7/23/2024	1969	RET ABN	UG-SERVICE
35936783	GRET	SVC	1/23/2020	1969	RET ABN	UG-SERVICE
41786378	GRET	SVC	6/19/2023	1969	RET ABN	UG-SERVICE
40616868	GRET	SVC	9/10/2022	1969	RET ABN	UG-SERVICE
42833096	GRET	SVC	7/22/2024	1969	RET ABN	UG-SERVICE
41253079	GRET	SVC	2/3/2023	1969	RET ABN	UG-SERVICE
41068027	GRET	SVC	12/15/2022	1969	RET ABN	UG-SERVICE
39703967	GRET	SVC	1/18/2022	1969	RET ABN	UG-SERVICE
39665277	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
38435783	GRET	SVC	5/4/2021	1969	RET ABN	UG-SERVICE
42216815	GRET	SVC	12/7/2023	1969	RET ABN	UG-SERVICE
42249677	GRET	SVC	12/20/2023	1969	RET ABN	UG-SERVICE
39983346	GRET	SVC	4/11/2022	1969	RET ABN	UG-SERVICE
39423637	GRET	SVC	11/15/2021	1969	RET ABN	UG-SERVICE
36122438	GRET	SVC	10/14/2020	1969	RET ABN	UG-SERVICE
37641860	GRET	SVC	11/19/2020	1969	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40472616	GRET	SVC	9/15/2022	1969	RET ABN	UG-SERVICE
39665814	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
41853474	GRET	SVC	7/12/2023	1969	RET ABN	UG-SERVICE
36106830	GRET	SVC	4/21/2020	1969	RET ABN	UG-SERVICE
39303367	GRET	SVC	10/19/2021	1969	RET ABN	UG-SERVICE
38194547	GRET	SVC	3/12/2021	1969	RET ABN	UG-SERVICE
42122256	GRET	SVC	9/18/2023	1969	RET ABN	UG-SERVICE
41844253	GRET	SVC	7/11/2023	1969	RET ABN	UG-SERVICE
41188318	GRET	SVC	1/24/2023	1969	RET ABN	UG-SERVICE
39665800	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
35678083	GRET	SVC	1/23/2020	1969	RET ABN	UG-SERVICE
40558767	GRET	SVC	8/10/2022	1969	RET ABN	UG-SERVICE
36751465	GRET	SVC	8/13/2020	1969	RET ABN	UG-SERVICE
41411153	GRET	SVC	4/2/2024	1969	RET ABN	UG-SERVICE
39691660	GRET	SVC	1/15/2022	1969	RET ABN	UG-SERVICE
37065553	GRET	SVC	10/20/2020	1969	RET ABN	UG-SERVICE
41896886	GRET	SVC	7/30/2023	1969	RET ABN	UG-SERVICE
38593802	GRET	SVC	8/31/2021	1969	RET ABN	UG-SERVICE
39665673	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
41245576	GRET	SVC	2/10/2023	1969	RET ABN	UG-SERVICE
39830451	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
37387501	GRET	SVC	11/5/2020	1969	RET ABN	UG-SERVICE
43365680	GRET	SVC	10/30/2024	1969	RET ABN	UG-SERVICE
43448533	GRET	SVC	8/19/2024	1969	RET ABN	UG-SERVICE
42600180	GRET	SVC	1/26/2024	1969	RET ABN	UG-SERVICE
37098911	GRET	SVC	10/29/2020	1969	RET ABN	UG-SERVICE
36885292	GRET	SVC	10/15/2020	1969	RET ABN	UG-SERVICE
36121359	GRET	SVC	10/16/2020	1969	RET ABN	UG-SERVICE
41411045	GRET	SVC	4/2/2024	1969	RET ABN	UG-SERVICE
39830449	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
41409244	GRET	SVC	4/2/2024	1969	RET ABN	UG-SERVICE
40498170	GRET	SVC	7/25/2022	1969	RET ABN	UG-SERVICE
38795282	GRET	SVC	7/1/2021	1969	RET ABN	UG-SERVICE
39830402	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
43365682	GRET	SVC	12/19/2024	1969	RET ABN	UG-SERVICE
42331726	GRET	SVC	11/6/2023	1969	RET ABN	UG-SERVICE
39831365	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
40324802	GRET	SVC	6/21/2022	1969	RET ABN	UG-SERVICE
35968036	GRET	SVC	2/25/2020	1969	RET ABN	UG-SERVICE
36121692	GRET	SVC	10/12/2020	1969	RET ABN	UG-SERVICE
41497333	GRET	SVC	4/24/2023	1969	RET ABN	UG-SERVICE
39665815	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
41141851	GRET	SVC	1/9/2023	1969	RET ABN	UG-SERVICE
39250840	GRET	SVC	10/11/2021	1969	RET ABN	UG-SERVICE
43493320	GRET	SVC	12/19/2024	1969	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36647011	GRET	SVC	7/13/2020	1969	RET ABN	UG-SERVICE
41436454	GRET	SVC	4/30/2023	1969	RET ABN	UG-SERVICE
39903460	GRET	SVC	3/29/2022	1969	RET ABN	UG-SERVICE
42314951	GRET	SVC	11/20/2023	1969	RET ABN	UG-SERVICE
42297446	GRET	SVC	11/1/2023	1969	RET ABN	UG-SERVICE
36396472	GRET	SVC	6/3/2020	1969	RET ABN	UG-SERVICE
39830352	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
36666324	GRET	SVC	7/22/2020	1969	RET ABN	UG-SERVICE
42984750	GRET	SVC	4/22/2024	1969	RET ABN	UG-SERVICE
38322242	GRET	SVC	12/21/2021	1969	RET ABN	UG-SERVICE
39771827	GRET	SVC	2/8/2022	1969	RET ABN	UG-SERVICE
39665805	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
40671208	GRET	SVC	9/17/2022	1969	RET ABN	UG-SERVICE
39830448	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
41223154	GRET	SVC	1/30/2023	1969	RET ABN	UG-SERVICE
41969489	GRET	SVC	7/31/2024	1969	RET ABN	UG-SERVICE
36485659	GRET	SVC	6/23/2020	1969	RET ABN	UG-SERVICE
40987260	GRET	SVC	11/29/2022	1969	RET ABN	UG-SERVICE
40478413	GRET	SVC	7/26/2022	1969	RET ABN	UG-SERVICE
40910571	GRET	SVC	11/8/2022	1969	RET ABN	UG-SERVICE
41230526	GRET	SVC	2/2/2023	1969	RET ABN	UG-SERVICE
41752183	GRET	SVC	6/13/2023	1969	RET ABN	UG-SERVICE
40234274	GRET	SVC	5/31/2022	1969	RET ABN	UG-SERVICE
42784509	GRET	SVC	4/16/2024	1969	RET ABN	UG-SERVICE
42404814	GRET	SVC	12/12/2023	1969	RET ABN	UG-SERVICE
36989293	GRET	SVC	8/11/2020	1969	RET ABN	UG-SERVICE
38875278	GRET	SVC	1/3/2022	1969	RET ABN	UG-SERVICE
36235878	GRET	SVC	12/16/2020	1969	RET ABN	UG-SERVICE
41436452	GRET	SVC	3/31/2023	1969	RET ABN	UG-SERVICE
38677037	GRET	SVC	7/7/2021	1969	RET ABN	UG-SERVICE
43323971	GRET	SVC	7/22/2024	1969	RET ABN	UG-SERVICE
37597540	GRET	SVC	11/17/2020	1969	RET ABN	UG-SERVICE
41968714	GRET	SVC	8/7/2023	1969	RET ABN	UG-SERVICE
38670221	GRET	SVC	6/23/2021	1969	RET ABN	UG-SERVICE
40111686	GRET	SVC	5/4/2022	1969	RET ABN	UG-SERVICE
38257099	GRET	SVC	3/22/2021	1969	RET ABN	UG-SERVICE
39935328	GRET	SVC	5/2/2022	1969	RET ABN	UG-SERVICE
41288083	GRET	SVC	3/17/2023	1969	RET ABN	UG-SERVICE
39830346	GRET	SVC	8/3/2022	1969	RET ABN	UG-SERVICE
38524218	GRET	SVC	6/15/2021	1969	RET ABN	UG-SERVICE
43203572	GRET	SVC	6/18/2024	1969	RET ABN	UG-SERVICE
36030739	GRET	SVC	2/14/2020	1969	RET ABN	UG-SERVICE
42216803	GRET	SVC	12/6/2023	1969	RET ABN	UG-SERVICE
36751436	GRET	SVC	10/5/2020	1969	RET ABN	UG-SERVICE
35876804	GRET	SVC	1/8/2020	1969	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38256808	GRET	SVC	4/1/2021	1969	RET ABN	UG-SERVICE
43274525	GRET	SVC	7/13/2024	1969	RET ABN	UG-SERVICE
36460197	GRET	SVC	6/18/2020	1969	RET ABN	UG-SERVICE
36670730	GRET	SVC	7/29/2020	1969	RET ABN	UG-SERVICE
42879026	GRET	SVC	4/2/2024	1969	RET ABN	UG-SERVICE
40500724	GRET	SVC	9/14/2022	1970	RET ABN	UG-SERVICE
41119748	GRET	SVC	1/3/2023	1970	RET ABN	UG-SERVICE
36183154	GRET	SVC	4/21/2020	1970	RET ABN	UG-SERVICE
39873582	GRET	SVC	3/14/2022	1970	RET ABN	UG-SERVICE
41401742	GRET	SVC	3/14/2023	1970	RET ABN	UG-SERVICE
43892423	GRET	SVC	12/3/2024	1970	RET ABN	UG-SERVICE
43799633	GRET	SVC	11/20/2024	1970	RET ABN	UG-SERVICE
39680096	GRET	SVC	1/12/2022	1970	RET ABN	UG-SERVICE
39450194	GRET	SVC	12/9/2021	1970	RET ABN	UG-SERVICE
41052713	GRET	SVC	1/12/2023	1970	RET ABN	UG-SERVICE
36350272	GRET	SVC	5/15/2020	1970	RET ABN	UG-SERVICE
40179803	GRET	SVC	5/18/2022	1970	RET ABN	UG-SERVICE
36283385	GRET	SVC	6/15/2020	1970	RET ABN	UG-SERVICE
39831475	GRET	SVC	8/3/2022	1970	RET ABN	UG-SERVICE
41075028	GRET	SVC	12/30/2022	1970	RET ABN	UG-SERVICE
42423918	GRET	SVC	11/28/2023	1970	RET ABN	UG-SERVICE
43353627	GRET	SVC	11/7/2024	1970	RET ABN	UG-SERVICE
41317159	GRET	SVC	3/4/2023	1970	RET ABN	UG-SERVICE
38441542	GRET	SVC	1/3/2022	1970	RET ABN	UG-SERVICE
36163049	GRET	SVC	3/24/2020	1970	RET ABN	UG-SERVICE
36118828	GRET	SVC	10/14/2020	1970	RET ABN	UG-SERVICE
41818696	GRET	SVC	7/22/2023	1970	RET ABN	UG-SERVICE
40963335	GRET	SVC	12/12/2022	1970	RET ABN	UG-SERVICE
36090177	GRET	SVC	3/6/2020	1970	RET ABN	UG-SERVICE
36057532	GRET	SVC	2/21/2020	1970	RET ABN	UG-SERVICE
43203666	GRET	SVC	6/19/2024	1970	RET ABN	UG-SERVICE
41659816	GRET	SVC	5/23/2023	1970	RET ABN	UG-SERVICE
41870478	GRET	SVC	7/18/2023	1970	RET ABN	UG-SERVICE
41052714	GRET	SVC	1/12/2023	1970	RET ABN	UG-SERVICE
39666317	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
36122378	GRET	SVC	10/14/2020	1970	RET ABN	UG-SERVICE
37055416	GRET	SVC	11/4/2020	1970	RET ABN	UG-SERVICE
42234544	GRET	SVC	10/17/2023	1970	RET ABN	UG-SERVICE
37324160	GRET	SVC	11/9/2020	1970	RET ABN	UG-SERVICE
43412674	GRET	SVC	8/14/2024	1970	RET ABN	UG-SERVICE
41473584	GRET	SVC	4/19/2023	1970	RET ABN	UG-SERVICE
40780609	GRET	SVC	10/13/2022	1970	RET ABN	UG-SERVICE
41882464	GRET	SVC	6/23/2023	1970	RET ABN	UG-SERVICE
36121770	GRET	SVC	10/12/2020	1970	RET ABN	UG-SERVICE
41330345	GRET	SVC	3/2/2023	1970	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42489092	GRET	SVC	12/18/2023	1970	RET ABN	UG-SERVICE
36283384	GRET	SVC	6/15/2020	1970	RET ABN	UG-SERVICE
36121348	GRET	SVC	11/5/2020	1970	RET ABN	UG-SERVICE
39716936	GRET	SVC	1/6/2022	1970	RET ABN	UG-SERVICE
43525078	GRET	SVC	10/15/2024	1970	RET ABN	UG-SERVICE
36283388	GRET	SVC	6/15/2020	1970	RET ABN	UG-SERVICE
40332367	GRET	SVC	6/22/2022	1970	RET ABN	UG-SERVICE
36702203	GRET	SVC	7/29/2020	1970	RET ABN	UG-SERVICE
40658153	GRET	SVC	9/14/2022	1970	RET ABN	UG-SERVICE
43807180	GRET	SVC	11/22/2024	1970	RET ABN	UG-SERVICE
40639350	GRET	SVC	8/31/2022	1970	RET ABN	UG-SERVICE
39550691	GRET	SVC	12/20/2021	1970	RET ABN	UG-SERVICE
39666400	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
41803298	GRET	SVC	6/26/2023	1970	RET ABN	UG-SERVICE
36282716	GRET	SVC	6/23/2020	1970	RET ABN	UG-SERVICE
39666404	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
36110443	GRET	SVC	3/9/2020	1970	RET ABN	UG-SERVICE
41229864	GRET	SVC	2/1/2023	1970	RET ABN	UG-SERVICE
39434287	GRET	SVC	11/19/2021	1970	RET ABN	UG-SERVICE
39666421	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
36122422	GRET	SVC	10/14/2020	1970	RET ABN	UG-SERVICE
43480939	GRET	SVC	10/25/2024	1970	RET ABN	UG-SERVICE
39666438	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
41279866	GRET	SVC	2/16/2023	1970	RET ABN	UG-SERVICE
38539150	GRET	SVC	6/28/2021	1970	RET ABN	UG-SERVICE
38608929	GRET	SVC	12/23/2021	1970	RET ABN	UG-SERVICE
43676679	GRET	SVC	10/15/2024	1970	RET ABN	UG-SERVICE
41916578	GRET	SVC	7/25/2023	1970	RET ABN	UG-SERVICE
37104386	GRET	SVC	10/26/2020	1970	RET ABN	UG-SERVICE
39666240	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
39666425	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
38772860	GRET	SVC	7/30/2021	1970	RET ABN	UG-SERVICE
39831477	GRET	SVC	8/3/2022	1970	RET ABN	UG-SERVICE
38407515	GRET	SVC	4/26/2021	1970	RET ABN	UG-SERVICE
43347408	GRET	SVC	7/24/2024	1970	RET ABN	UG-SERVICE
43789058	GRET	SVC	12/14/2024	1970	RET ABN	UG-SERVICE
42386287	GRET	SVC	11/14/2023	1970	RET ABN	UG-SERVICE
39809487	GRET	SVC	8/3/2022	1970	RET ABN	UG-SERVICE
40490995	GRET	SVC	7/29/2022	1970	RET ABN	UG-SERVICE
41408062	GRET	SVC	4/2/2024	1970	RET ABN	UG-SERVICE
36701300	GRET	SVC	7/30/2020	1970	RET ABN	UG-SERVICE
39424068	GRET	SVC	6/27/2022	1970	RET ABN	UG-SERVICE
40749589	GRET	SVC	5/13/2024	1970	RET ABN	UG-SERVICE
36142348	GRET	SVC	3/17/2020	1970	RET ABN	UG-SERVICE
38537594	GRET	SVC	4/13/2021	1970	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
35918148	GRET	SVC	1/20/2020	1970	RET ABN	UG-SERVICE
42378966	GRET	SVC	11/14/2023	1970	RET ABN	UG-SERVICE
39892775	GRET	SVC	6/2/2022	1970	RET ABN	UG-SERVICE
38107943	GRET	SVC	2/24/2021	1970	RET ABN	UG-SERVICE
40118767	GRET	SVC	5/9/2022	1970	RET ABN	UG-SERVICE
43151327	GRET	SVC	9/19/2024	1970	RET ABN	UG-SERVICE
40806481	GRET	SVC	10/10/2022	1970	RET ABN	UG-SERVICE
37957641	GRET	SVC	2/18/2021	1970	RET ABN	UG-SERVICE
42412181	GRET	SVC	11/20/2023	1970	RET ABN	UG-SERVICE
36283383	GRET	SVC	6/15/2020	1970	RET ABN	UG-SERVICE
42759492	GRET	SVC	2/27/2024	1970	RET ABN	UG-SERVICE
42833938	GRET	SVC	7/23/2024	1970	RET ABN	UG-SERVICE
42833934	GRET	SVC	7/23/2024	1970	RET ABN	UG-SERVICE
40808302	GRET	SVC	11/11/2022	1970	RET ABN	UG-SERVICE
38676767	GRET	SVC	8/2/2021	1970	RET ABN	UG-SERVICE
42487684	GRET	SVC	7/18/2024	1970	RET ABN	UG-SERVICE
42834145	GRET	SVC	8/5/2024	1970	RET ABN	UG-SERVICE
39935386	GRET	SVC	5/14/2022	1970	RET ABN	UG-SERVICE
36122434	GRET	SVC	10/14/2020	1970	RET ABN	UG-SERVICE
41407613	GRET	SVC	4/2/2024	1970	RET ABN	UG-SERVICE
41291591	GRET	SVC	2/20/2023	1970	RET ABN	UG-SERVICE
43280667	GRET	SVC	12/3/2024	1970	RET ABN	UG-SERVICE
43640980	GRET	SVC	10/1/2024	1970	RET ABN	UG-SERVICE
40318264	GRET	SVC	6/22/2022	1970	RET ABN	UG-SERVICE
43506838	GRET	SVC	9/27/2024	1970	RET ABN	UG-SERVICE
36701074	GRET	SVC	7/29/2020	1970	RET ABN	UG-SERVICE
38912205	GRET	SVC	7/7/2022	1970	RET ABN	UG-SERVICE
43705149	GRET	SVC	10/16/2024	1970	RET ABN	UG-SERVICE
41837155	GRET	SVC	7/7/2023	1970	RET ABN	UG-SERVICE
43649294	GRET	SVC	12/4/2024	1970	RET ABN	UG-SERVICE
42073738	GRET	SVC	9/29/2023	1970	RET ABN	UG-SERVICE
39666740	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
39666402	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
38545124	GRET	SVC	5/25/2021	1970	RET ABN	UG-SERVICE
39666481	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
43649292	GRET	SVC	12/5/2024	1970	RET ABN	UG-SERVICE
36122421	GRET	SVC	10/14/2020	1970	RET ABN	UG-SERVICE
42791899	GRET	SVC	3/5/2024	1970	RET ABN	UG-SERVICE
42956336	GRET	SVC	9/19/2024	1970	RET ABN	UG-SERVICE
39666439	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
40747501	GRET	SVC	9/28/2022	1970	RET ABN	UG-SERVICE
42487781	GRET	SVC	7/18/2024	1970	RET ABN	UG-SERVICE
36283387	GRET	SVC	6/15/2020	1970	RET ABN	UG-SERVICE
42381320	GRET	SVC	11/15/2023	1970	RET ABN	UG-SERVICE
36283382	GRET	SVC	6/15/2020	1970	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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39423524	GRET	SVC	6/27/2022	1970	RET ABN	UG-SERVICE
40947077	GRET	SVC	11/25/2022	1970	RET ABN	UG-SERVICE
36085532	GRET	SVC	3/4/2020	1970	RET ABN	UG-SERVICE
42824972	GRET	SVC	3/12/2024	1970	RET ABN	UG-SERVICE
42514799	GRET	SVC	12/15/2023	1970	RET ABN	UG-SERVICE
40811497	GRET	SVC	3/8/2023	1970	RET ABN	UG-SERVICE
43481199	GRET	SVC	10/24/2024	1970	RET ABN	UG-SERVICE
35960294	GRET	SVC	1/29/2020	1970	RET ABN	UG-SERVICE
42760335	GRET	SVC	7/30/2024	1970	RET ABN	UG-SERVICE
40556773	GRET	SVC	8/12/2022	1970	RET ABN	UG-SERVICE
40977040	GRET	SVC	11/28/2022	1970	RET ABN	UG-SERVICE
39831652	GRET	SVC	8/3/2022	1970	RET ABN	UG-SERVICE
41298680	GRET	SVC	2/21/2023	1970	RET ABN	UG-SERVICE
43650227	GRET	SVC	12/9/2024	1970	RET ABN	UG-SERVICE
40770432	GRET	SVC	9/29/2022	1970	RET ABN	UG-SERVICE
41296147	GRET	SVC	2/20/2023	1970	RET ABN	UG-SERVICE
41401435	GRET	SVC	3/24/2023	1970	RET ABN	UG-SERVICE
39666423	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
36391042	GRET	SVC	6/4/2020	1970	RET ABN	UG-SERVICE
40780612	GRET	SVC	10/10/2022	1970	RET ABN	UG-SERVICE
39831645	GRET	SVC	8/3/2022	1970	RET ABN	UG-SERVICE
41911980	GRET	SVC	8/1/2023	1970	RET ABN	UG-SERVICE
42494200	GRET	SVC	8/1/2024	1970	RET ABN	UG-SERVICE
40655699	GRET	SVC	8/31/2022	1970	RET ABN	UG-SERVICE
43648971	GRET	SVC	12/6/2024	1970	RET ABN	UG-SERVICE
41838366	GRET	SVC	7/7/2023	1970	RET ABN	UG-SERVICE
39831575	GRET	SVC	8/3/2022	1970	RET ABN	UG-SERVICE
36136190	GRET	SVC	4/23/2020	1970	RET ABN	UG-SERVICE
40338237	GRET	SVC	6/21/2022	1970	RET ABN	UG-SERVICE
43578156	GRET	SVC	9/17/2024	1970	RET ABN	UG-SERVICE
36077428	GRET	SVC	3/2/2020	1970	RET ABN	UG-SERVICE
38106693	GRET	SVC	2/10/2021	1970	RET ABN	UG-SERVICE
36992559	GRET	SVC	9/30/2020	1970	RET ABN	UG-SERVICE
36704451	GRET	SVC	7/30/2020	1970	RET ABN	UG-SERVICE
39423215	GRET	SVC	6/27/2022	1970	RET ABN	UG-SERVICE
38692662	GRET	SVC	7/2/2021	1970	RET ABN	UG-SERVICE
39649243	GRET	SVC	2/15/2022	1970	RET ABN	UG-SERVICE
39654870	GRET	SVC	6/28/2022	1970	RET ABN	UG-SERVICE
40231463	GRET	SVC	5/31/2022	1970	RET ABN	UG-SERVICE
40358943	GRET	SVC	6/28/2022	1970	RET ABN	UG-SERVICE
37741510	GRET	SVC	11/24/2020	1970	RET ABN	UG-SERVICE
40359856	GRET	SVC	6/28/2022	1970	RET ABN	UG-SERVICE
42321636	GRET	SVC	11/6/2023	1970	RET ABN	UG-SERVICE
36110213	GRET	SVC	10/12/2020	1970	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38966217	GRET	SVC	8/30/2021	1970	RET ABN	UG-SERVICE
38051914	GRET	SVC	1/25/2021	1970	RET ABN	UG-SERVICE
37098508	GRET	SVC	10/19/2020	1970	RET ABN	UG-SERVICE
42833937	GRET	SVC	7/23/2024	1970	RET ABN	UG-SERVICE
43365688	GRET	SVC	10/21/2024	1970	RET ABN	UG-SERVICE
42029728	GRET	SVC	8/25/2023	1970	RET ABN	UG-SERVICE
39666422	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
39666426	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
35846431	GRET	SVC	1/2/2020	1970	RET ABN	UG-SERVICE
39880056	GRET	SVC	3/14/2022	1970	RET ABN	UG-SERVICE
38110647	GRET	SVC	2/25/2021	1970	RET ABN	UG-SERVICE
43648976	GRET	SVC	12/5/2024	1970	RET ABN	UG-SERVICE
41411154	GRET	SVC	4/2/2024	1970	RET ABN	UG-SERVICE
36108480	GRET	SVC	10/12/2020	1970	RET ABN	UG-SERVICE
42487682	GRET	SVC	7/18/2024	1970	RET ABN	UG-SERVICE
41067833	GRET	SVC	12/22/2022	1970	RET ABN	UG-SERVICE
40205533	GRET	SVC	6/11/2022	1970	RET ABN	UG-SERVICE
39666427	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
39424069	GRET	SVC	6/27/2022	1970	RET ABN	UG-SERVICE
37011547	GRET	SVC	10/1/2020	1970	RET ABN	UG-SERVICE
41401740	GRET	SVC	3/14/2023	1970	RET ABN	UG-SERVICE
40273945	GRET	SVC	6/8/2022	1970	RET ABN	UG-SERVICE
38537392	GRET	SVC	5/27/2021	1970	RET ABN	UG-SERVICE
36877039	GRET	SVC	8/25/2020	1970	RET ABN	UG-SERVICE
35970045	GRET	SVC	2/3/2020	1970	RET ABN	UG-SERVICE
42956846	GRET	SVC	7/18/2024	1970	RET ABN	UG-SERVICE
41401961	GRET	SVC	3/9/2023	1970	RET ABN	UG-SERVICE
40356392	GRET	SVC	6/27/2022	1970	RET ABN	UG-SERVICE
42469443	GRET	SVC	12/12/2023	1970	RET ABN	UG-SERVICE
39666431	GRET	SVC	11/18/2022	1970	RET ABN	UG-SERVICE
36252638	GRET	SVC	5/1/2020	1970	RET ABN	UG-SERVICE
43649298	GRET	SVC	12/6/2024	1970	RET ABN	UG-SERVICE
41279146	GRET	SVC	3/24/2023	1971	RET ABN	UG-SERVICE
39079965	GRET	SVC	9/2/2021	1971	RET ABN	UG-SERVICE
39819166	GRET	SVC	2/28/2022	1971	RET ABN	UG-SERVICE
42002925	GRET	SVC	8/15/2023	1971	RET ABN	UG-SERVICE
38441323	GRET	SVC	1/3/2022	1971	RET ABN	UG-SERVICE
38356367	GRET	SVC	4/15/2021	1971	RET ABN	UG-SERVICE
42956324	GRET	SVC	9/19/2024	1971	RET ABN	UG-SERVICE
39920971	GRET	SVC	4/5/2022	1971	RET ABN	UG-SERVICE
35856442	GRET	SVC	1/9/2020	1971	RET ABN	UG-SERVICE
43904906	GRET	SVC	12/4/2024	1971	RET ABN	UG-SERVICE
36711290	GRET	SVC	7/28/2020	1971	RET ABN	UG-SERVICE
41222691	GRET	SVC	1/20/2023	1971	RET ABN	UG-SERVICE
43151329	GRET	SVC	9/19/2024	1971	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41450269	GRET	SVC	4/10/2023	1971	RET ABN	UG-SERVICE
41411223	GRET	SVC	4/2/2024	1971	RET ABN	UG-SERVICE
39090216	GRET	SVC	9/8/2021	1971	RET ABN	UG-SERVICE
42902428	GRET	SVC	4/10/2024	1971	RET ABN	UG-SERVICE
41083627	GRET	SVC	2/13/2023	1971	RET ABN	UG-SERVICE
41775070	GRET	SVC	6/27/2023	1971	RET ABN	UG-SERVICE
37425042	GRET	SVC	11/11/2020	1971	RET ABN	UG-SERVICE
41411189	GRET	SVC	4/2/2024	1971	RET ABN	UG-SERVICE
36319078	GRET	SVC	4/27/2020	1971	RET ABN	UG-SERVICE
42534170	GRET	SVC	1/2/2024	1971	RET ABN	UG-SERVICE
41436886	GRET	SVC	3/27/2023	1971	RET ABN	UG-SERVICE
42448121	GRET	SVC	12/4/2023	1971	RET ABN	UG-SERVICE
41591360	GRET	SVC	5/2/2023	1971	RET ABN	UG-SERVICE
42327602	GRET	SVC	12/7/2023	1971	RET ABN	UG-SERVICE
36035401	GRET	SVC	2/17/2020	1971	RET ABN	UG-SERVICE
42320646	GRET	SVC	11/7/2023	1971	RET ABN	UG-SERVICE
38457555	GRET	SVC	5/7/2021	1971	RET ABN	UG-SERVICE
43267508	GRET	SVC	7/18/2024	1971	RET ABN	UG-SERVICE
41429913	GRET	SVC	3/21/2023	1971	RET ABN	UG-SERVICE
38097220	GRET	SVC	9/2/2021	1971	RET ABN	UG-SERVICE
41244030	GRET	SVC	3/20/2023	1971	RET ABN	UG-SERVICE
41029976	GRET	SVC	1/21/2023	1971	RET ABN	UG-SERVICE
41807843	GRET	SVC	6/26/2023	1971	RET ABN	UG-SERVICE
43364879	GRET	SVC	12/17/2024	1971	RET ABN	UG-SERVICE
41179619	GRET	SVC	1/18/2023	1971	RET ABN	UG-SERVICE
40938774	GRET	SVC	10/5/2022	1971	RET ABN	UG-SERVICE
36122498	GRET	SVC	10/30/2020	1971	RET ABN	UG-SERVICE
41411226	GRET	SVC	4/2/2024	1971	RET ABN	UG-SERVICE
39078482	GRET	SVC	9/7/2021	1971	RET ABN	UG-SERVICE
38252169	GRET	SVC	3/18/2021	1971	RET ABN	UG-SERVICE
41411427	GRET	SVC	11/2/2023	1971	RET ABN	UG-SERVICE
43480497	GRET	SVC	9/14/2024	1971	RET ABN	UG-SERVICE
42132870	GRET	SVC	9/20/2023	1971	RET ABN	UG-SERVICE
40618057	GRET	SVC	8/24/2022	1971	RET ABN	UG-SERVICE
38507684	GRET	SVC	5/18/2021	1971	RET ABN	UG-SERVICE
42314997	GRET	SVC	11/6/2023	1971	RET ABN	UG-SERVICE
36939018	GRET	SVC	9/22/2020	1971	RET ABN	UG-SERVICE
39312873	GRET	SVC	10/9/2021	1971	RET ABN	UG-SERVICE
43325228	GRET	SVC	7/16/2024	1971	RET ABN	UG-SERVICE
42328017	GRET	SVC	12/8/2023	1971	RET ABN	UG-SERVICE
43591096	GRET	SVC	9/16/2024	1971	RET ABN	UG-SERVICE
43506889	GRET	SVC	10/11/2024	1971	RET ABN	UG-SERVICE
37982149	GRET	SVC	1/6/2021	1971	RET ABN	UG-SERVICE
42192947	GRET	SVC	10/6/2023	1971	RET ABN	UG-SERVICE
39574845	GRET	SVC	12/22/2021	1971	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42522981	GRET	SVC	12/29/2023	1971	RET ABN	UG-SERVICE
38014263	GRET	SVC	1/14/2021	1971	RET ABN	UG-SERVICE
36105786	GRET	SVC	2/10/2020	1971	RET ABN	UG-SERVICE
41785520	GRET	SVC	6/19/2023	1971	RET ABN	UG-SERVICE
36710986	GRET	SVC	8/3/2020	1971	RET ABN	UG-SERVICE
39405134	GRET	SVC	12/7/2021	1971	RET ABN	UG-SERVICE
41870461	GRET	SVC	7/8/2023	1971	RET ABN	UG-SERVICE
38521824	GRET	SVC	5/20/2021	1971	RET ABN	UG-SERVICE
37025090	GRET	SVC	8/21/2020	1971	RET ABN	UG-SERVICE
35767016	GRET	SVC	1/8/2020	1971	RET ABN	UG-SERVICE
36120705	GRET	SVC	11/5/2020	1971	RET ABN	UG-SERVICE
39535924	GRET	SVC	12/14/2021	1971	RET ABN	UG-SERVICE
36255035	GRET	SVC	5/5/2020	1971	RET ABN	UG-SERVICE
43168069	GRET	SVC	6/28/2024	1971	RET ABN	UG-SERVICE
41741982	GRET	SVC	6/14/2023	1971	RET ABN	UG-SERVICE
41860747	GRET	SVC	8/16/2023	1971	RET ABN	UG-SERVICE
40521713	GRET	SVC	8/23/2022	1971	RET ABN	UG-SERVICE
40129808	GRET	SVC	5/10/2022	1971	RET ABN	UG-SERVICE
38547807	GRET	SVC	5/27/2021	1971	RET ABN	UG-SERVICE
43344403	GRET	SVC	7/23/2024	1971	RET ABN	UG-SERVICE
38260421	GRET	SVC	12/14/2021	1971	RET ABN	UG-SERVICE
41242161	GRET	SVC	2/24/2023	1971	RET ABN	UG-SERVICE
43584359	GRET	SVC	9/25/2024	1971	RET ABN	UG-SERVICE
36795096	GRET	SVC	9/1/2020	1971	RET ABN	UG-SERVICE
39990979	GRET	SVC	4/8/2022	1971	RET ABN	UG-SERVICE
39759178	GRET	SVC	8/16/2021	1971	RET ABN	UG-SERVICE
41009755	GRET	SVC	12/1/2022	1971	RET ABN	UG-SERVICE
43399718	GRET	SVC	8/9/2024	1971	RET ABN	UG-SERVICE
43347538	GRET	SVC	7/22/2024	1971	RET ABN	UG-SERVICE
42438487	GRET	SVC	12/5/2023	1971	RET ABN	UG-SERVICE
40251452	GRET	SVC	7/19/2022	1971	RET ABN	UG-SERVICE
37948598	GRET	SVC	12/22/2020	1971	RET ABN	UG-SERVICE
41317537	GRET	SVC	3/3/2023	1971	RET ABN	UG-SERVICE
41083628	GRET	SVC	1/11/2023	1971	RET ABN	UG-SERVICE
39223946	GRET	SVC	9/29/2021	1971	RET ABN	UG-SERVICE
37094270	GRET	SVC	10/30/2020	1971	RET ABN	UG-SERVICE
40249263	GRET	SVC	6/6/2022	1971	RET ABN	UG-SERVICE
35967994	GRET	SVC	2/28/2020	1971	RET ABN	UG-SERVICE
42670286	GRET	SVC	9/19/2024	1971	RET ABN	UG-SERVICE
39786506	GRET	SVC	2/14/2022	1971	RET ABN	UG-SERVICE
36259917	GRET	SVC	4/16/2020	1971	RET ABN	UG-SERVICE
38094297	GRET	SVC	2/8/2021	1971	RET ABN	UG-SERVICE
38441371	GRET	SVC	1/6/2022	1971	RET ABN	UG-SERVICE
41411664	GRET	SVC	4/2/2024	1971	RET ABN	UG-SERVICE
40341445	GRET	SVC	6/24/2022	1971	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43464130	GRET	SVC	8/20/2024	1971	RET ABN	UG-SERVICE
42437069	GRET	SVC	11/29/2023	1971	RET ABN	UG-SERVICE
36918266	GRET	SVC	9/14/2020	1971	RET ABN	UG-SERVICE
36592936	GRET	SVC	7/8/2020	1971	RET ABN	UG-SERVICE
39922193	GRET	SVC	3/24/2022	1971	RET ABN	UG-SERVICE
43364925	GRET	SVC	10/18/2024	1971	RET ABN	UG-SERVICE
42589542	GRET	SVC	1/24/2024	1971	RET ABN	UG-SERVICE
43480931	GRET	SVC	9/14/2024	1971	RET ABN	UG-SERVICE
38609629	GRET	SVC	6/9/2021	1971	RET ABN	UG-SERVICE
36283571	GRET	SVC	4/30/2020	1971	RET ABN	UG-SERVICE
40624086	GRET	SVC	8/30/2022	1971	RET ABN	UG-SERVICE
36709410	GRET	SVC	7/28/2020	1971	RET ABN	UG-SERVICE
43565122	GRET	SVC	9/9/2024	1971	RET ABN	UG-SERVICE
42330509	GRET	SVC	11/6/2023	1971	RET ABN	UG-SERVICE
36248250	GRET	SVC	5/6/2020	1971	RET ABN	UG-SERVICE
41584265	GRET	SVC	5/1/2023	1971	RET ABN	UG-SERVICE
38042126	GRET	SVC	1/22/2021	1971	RET ABN	UG-SERVICE
40341396	GRET	SVC	6/24/2022	1971	RET ABN	UG-SERVICE
37994124	GRET	SVC	1/11/2021	1971	RET ABN	UG-SERVICE
43480499	GRET	SVC	9/14/2024	1971	RET ABN	UG-SERVICE
36314805	GRET	SVC	5/8/2020	1971	RET ABN	UG-SERVICE
41411267	GRET	SVC	4/2/2024	1971	RET ABN	UG-SERVICE
40737724	GRET	SVC	9/27/2022	1971	RET ABN	UG-SERVICE
42138574	GRET	SVC	9/19/2023	1971	RET ABN	UG-SERVICE
40675869	GRET	SVC	9/13/2022	1971	RET ABN	UG-SERVICE
38707309	GRET	SVC	8/9/2021	1971	RET ABN	UG-SERVICE
42014187	GRET	SVC	8/21/2023	1971	RET ABN	UG-SERVICE
40917638	GRET	SVC	11/16/2022	1971	RET ABN	UG-SERVICE
43460131	GRET	SVC	8/27/2024	1971	RET ABN	UG-SERVICE
40700097	GRET	SVC	9/14/2022	1972	RET ABN	UG-SERVICE
41414154	GRET	SVC	3/20/2023	1972	RET ABN	UG-SERVICE
42514066	GRET	SVC	12/26/2023	1972	RET ABN	UG-SERVICE
43480932	GRET	SVC	9/14/2024	1972	RET ABN	UG-SERVICE
41918341	GRET	SVC	8/16/2023	1972	RET ABN	UG-SERVICE
41182817	GRET	SVC	3/1/2023	1972	RET ABN	UG-SERVICE
41139253	GRET	SVC	1/27/2023	1972	RET ABN	UG-SERVICE
40273700	GRET	SVC	6/9/2022	1972	RET ABN	UG-SERVICE
39475344	GRET	SVC	11/29/2021	1972	RET ABN	UG-SERVICE
42956850	GRET	SVC	7/18/2024	1972	RET ABN	UG-SERVICE
37898340	GRET	SVC	12/7/2020	1972	RET ABN	UG-SERVICE
40462865	GRET	SVC	7/14/2022	1972	RET ABN	UG-SERVICE
41402221	GRET	SVC	3/15/2023	1972	RET ABN	UG-SERVICE
43081215	GRET	SVC	5/17/2024	1972	RET ABN	UG-SERVICE
40991106	GRET	SVC	11/21/2022	1972	RET ABN	UG-SERVICE
43554625	GRET	SVC	9/13/2024	1972	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
35993848	GRET	SVC	6/16/2020	1972	RET ABN	UG-SERVICE
41429935	GRET	SVC	9/19/2023	1972	RET ABN	UG-SERVICE
36194997	GRET	SVC	4/28/2020	1972	RET ABN	UG-SERVICE
43699979	GRET	SVC	10/15/2024	1972	RET ABN	UG-SERVICE
37914376	GRET	SVC	12/6/2020	1972	RET ABN	UG-SERVICE
41411410	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
42438334	GRET	SVC	12/5/2023	1972	RET ABN	UG-SERVICE
42520328	GRET	SVC	12/18/2023	1972	RET ABN	UG-SERVICE
41407880	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
41242165	GRET	SVC	3/2/2023	1972	RET ABN	UG-SERVICE
38960829	GRET	SVC	8/24/2021	1972	RET ABN	UG-SERVICE
40325248	GRET	SVC	7/13/2022	1972	RET ABN	UG-SERVICE
42122080	GRET	SVC	9/16/2023	1972	RET ABN	UG-SERVICE
36164807	GRET	SVC	3/23/2020	1972	RET ABN	UG-SERVICE
42156649	GRET	SVC	9/26/2023	1972	RET ABN	UG-SERVICE
41430060	GRET	SVC	9/12/2023	1972	RET ABN	UG-SERVICE
41430069	GRET	SVC	9/13/2023	1972	RET ABN	UG-SERVICE
39849156	GRET	SVC	2/28/2022	1972	RET ABN	UG-SERVICE
40881642	GRET	SVC	11/1/2022	1972	RET ABN	UG-SERVICE
41407390	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
40896029	GRET	SVC	11/10/2022	1972	RET ABN	UG-SERVICE
36695038	GRET	SVC	8/5/2020	1972	RET ABN	UG-SERVICE
43679955	GRET	SVC	11/1/2024	1972	RET ABN	UG-SERVICE
42487785	GRET	SVC	7/31/2024	1972	RET ABN	UG-SERVICE
41402232	GRET	SVC	3/15/2023	1972	RET ABN	UG-SERVICE
42435907	GRET	SVC	9/19/2024	1972	RET ABN	UG-SERVICE
38363161	GRET	SVC	4/19/2021	1972	RET ABN	UG-SERVICE
42405710	GRET	SVC	12/8/2023	1972	RET ABN	UG-SERVICE
41214288	GRET	SVC	12/11/2023	1972	RET ABN	UG-SERVICE
40492259	GRET	SVC	8/14/2022	1972	RET ABN	UG-SERVICE
41411281	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
42214614	GRET	SVC	10/11/2023	1972	RET ABN	UG-SERVICE
38909290	GRET	SVC	8/16/2021	1972	RET ABN	UG-SERVICE
42300904	GRET	SVC	11/1/2023	1972	RET ABN	UG-SERVICE
43746155	GRET	SVC	12/11/2024	1972	RET ABN	UG-SERVICE
43868498	GRET	SVC	11/26/2024	1972	RET ABN	UG-SERVICE
43740061	GRET	SVC	12/4/2024	1972	RET ABN	UG-SERVICE
43739938	GRET	SVC	12/4/2024	1972	RET ABN	UG-SERVICE
42049249	GRET	SVC	8/30/2023	1972	RET ABN	UG-SERVICE
36199035	GRET	SVC	4/23/2020	1972	RET ABN	UG-SERVICE
41253576	GRET	SVC	2/10/2023	1972	RET ABN	UG-SERVICE
41677672	GRET	SVC	5/27/2023	1972	RET ABN	UG-SERVICE
41839631	GRET	SVC	7/6/2023	1972	RET ABN	UG-SERVICE
39759516	GRET	SVC	2/7/2022	1972	RET ABN	UG-SERVICE
39926695	GRET	SVC	4/9/2022	1972	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39532710	GRET	SVC	12/14/2021	1972	RET ABN	UG-SERVICE
41654517	GRET	SVC	5/18/2023	1972	RET ABN	UG-SERVICE
39346682	GRET	SVC	10/28/2021	1972	RET ABN	UG-SERVICE
37070751	GRET	SVC	10/13/2020	1972	RET ABN	UG-SERVICE
37926012	GRET	SVC	12/16/2020	1972	RET ABN	UG-SERVICE
42834341	GRET	SVC	7/23/2024	1972	RET ABN	UG-SERVICE
42833380	GRET	SVC	7/22/2024	1972	RET ABN	UG-SERVICE
43480658	GRET	SVC	9/11/2024	1972	RET ABN	UG-SERVICE
36672292	GRET	SVC	7/23/2020	1972	RET ABN	UG-SERVICE
40552246	GRET	SVC	8/11/2022	1972	RET ABN	UG-SERVICE
38469249	GRET	SVC	6/1/2021	1972	RET ABN	UG-SERVICE
41273360	GRET	SVC	2/16/2023	1972	RET ABN	UG-SERVICE
43760724	GRET	SVC	10/23/2024	1972	RET ABN	UG-SERVICE
40333213	GRET	SVC	6/23/2022	1972	RET ABN	UG-SERVICE
43480998	GRET	SVC	11/16/2024	1972	RET ABN	UG-SERVICE
37926212	GRET	SVC	12/15/2020	1972	RET ABN	UG-SERVICE
41411234	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
41448025	GRET	SVC	3/26/2023	1972	RET ABN	UG-SERVICE
41188560	GRET	SVC	2/13/2023	1972	RET ABN	UG-SERVICE
39930272	GRET	SVC	3/31/2022	1972	RET ABN	UG-SERVICE
43739936	GRET	SVC	12/4/2024	1972	RET ABN	UG-SERVICE
39947193	GRET	SVC	3/29/2022	1972	RET ABN	UG-SERVICE
40418092	GRET	SVC	7/14/2022	1972	RET ABN	UG-SERVICE
43120516	GRET	SVC	5/21/2024	1972	RET ABN	UG-SERVICE
41411268	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
40933307	GRET	SVC	11/15/2022	1972	RET ABN	UG-SERVICE
39797719	GRET	SVC	2/15/2022	1972	RET ABN	UG-SERVICE
42381531	GRET	SVC	11/17/2023	1972	RET ABN	UG-SERVICE
43862097	GRET	SVC	12/9/2024	1972	RET ABN	UG-SERVICE
39935371	GRET	SVC	6/2/2022	1972	RET ABN	UG-SERVICE
42072075	GRET	SVC	9/5/2023	1972	RET ABN	UG-SERVICE
43342129	GRET	SVC	7/29/2024	1972	RET ABN	UG-SERVICE
41411275	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
35772295	GRET	SVC	1/2/2020	1972	RET ABN	UG-SERVICE
43480928	GRET	SVC	9/14/2024	1972	RET ABN	UG-SERVICE
38432241	GRET	SVC	4/29/2021	1972	RET ABN	UG-SERVICE
41740533	GRET	SVC	6/13/2023	1972	RET ABN	UG-SERVICE
43740062	GRET	SVC	12/4/2024	1972	RET ABN	UG-SERVICE
43186501	GRET	SVC	6/17/2024	1972	RET ABN	UG-SERVICE
41860698	GRET	SVC	7/13/2023	1972	RET ABN	UG-SERVICE
38343815	GRET	SVC	4/10/2021	1972	RET ABN	UG-SERVICE
41273211	GRET	SVC	2/16/2023	1972	RET ABN	UG-SERVICE
38703736	GRET	SVC	7/7/2021	1972	RET ABN	UG-SERVICE
39016838	GRET	SVC	8/16/2021	1972	RET ABN	UG-SERVICE
42412478	GRET	SVC	11/28/2023	1972	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41284187	GRET	SVC	3/15/2023	1972	RET ABN	UG-SERVICE
42294230	GRET	SVC	10/30/2023	1972	RET ABN	UG-SERVICE
36339718	GRET	SVC	5/20/2020	1972	RET ABN	UG-SERVICE
42286974	GRET	SVC	10/30/2023	1972	RET ABN	UG-SERVICE
39243683	GRET	SVC	11/19/2021	1972	RET ABN	UG-SERVICE
39830345	GRET	SVC	8/3/2022	1972	RET ABN	UG-SERVICE
41424508	GRET	SVC	10/18/2023	1972	RET ABN	UG-SERVICE
38557501	GRET	SVC	6/2/2021	1972	RET ABN	UG-SERVICE
38795268	GRET	SVC	7/17/2021	1972	RET ABN	UG-SERVICE
43480927	GRET	SVC	9/14/2024	1972	RET ABN	UG-SERVICE
42427053	GRET	SVC	9/19/2024	1972	RET ABN	UG-SERVICE
43156137	GRET	SVC	6/1/2024	1972	RET ABN	UG-SERVICE
43008937	GRET	SVC	5/3/2024	1972	RET ABN	UG-SERVICE
40394919	GRET	SVC	7/7/2022	1972	RET ABN	UG-SERVICE
39830356	GRET	SVC	8/3/2022	1972	RET ABN	UG-SERVICE
42833350	GRET	SVC	7/22/2024	1972	RET ABN	UG-SERVICE
38776468	GRET	SVC	8/2/2021	1972	RET ABN	UG-SERVICE
41032552	GRET	SVC	12/15/2022	1972	RET ABN	UG-SERVICE
39848783	GRET	SVC	3/4/2022	1972	RET ABN	UG-SERVICE
42585505	GRET	SVC	1/29/2024	1972	RET ABN	UG-SERVICE
41887706	GRET	SVC	7/17/2023	1972	RET ABN	UG-SERVICE
43678698	GRET	SVC	10/16/2024	1972	RET ABN	UG-SERVICE
43649102	GRET	SVC	10/8/2024	1972	RET ABN	UG-SERVICE
43529723	GRET	SVC	12/16/2024	1972	RET ABN	UG-SERVICE
40245550	GRET	SVC	9/9/2022	1972	RET ABN	UG-SERVICE
38490941	GRET	SVC	5/17/2021	1972	RET ABN	UG-SERVICE
42487347	GRET	SVC	7/18/2024	1972	RET ABN	UG-SERVICE
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41008615	GRET	SVC	12/8/2022	1972	RET ABN	UG-SERVICE
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43189275	GRET	SVC	6/17/2024	1972	RET ABN	UG-SERVICE
40340999	GRET	SVC	6/23/2022	1972	RET ABN	UG-SERVICE
39916056	GRET	SVC	5/2/2022	1972	RET ABN	UG-SERVICE
39471032	GRET	SVC	12/2/2021	1972	RET ABN	UG-SERVICE
37052222	GRET	SVC	8/29/2020	1972	RET ABN	UG-SERVICE
41223060	GRET	SVC	1/30/2023	1972	RET ABN	UG-SERVICE
42833349	GRET	SVC	7/22/2024	1972	RET ABN	UG-SERVICE
37141842	GRET	SVC	11/17/2020	1972	RET ABN	UG-SERVICE
41411273	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
41411280	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
40019113	GRET	SVC	5/27/2022	1972	RET ABN	UG-SERVICE
43223752	GRET	SVC	6/13/2024	1972	RET ABN	UG-SERVICE
36701097	GRET	SVC	9/8/2020	1972	RET ABN	UG-SERVICE
41411079	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41423578	GRET	SVC	10/18/2023	1972	RET ABN	UG-SERVICE
41242610	GRET	SVC	3/13/2023	1972	RET ABN	UG-SERVICE
36335575	GRET	SVC	5/19/2020	1972	RET ABN	UG-SERVICE
41407816	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
43480929	GRET	SVC	9/14/2024	1972	RET ABN	UG-SERVICE
43480930	GRET	SVC	9/14/2024	1972	RET ABN	UG-SERVICE
39668979	GRET	SVC	1/19/2022	1972	RET ABN	UG-SERVICE
38622330	GRET	SVC	8/23/2021	1972	RET ABN	UG-SERVICE
41255101	GRET	SVC	2/15/2023	1972	RET ABN	UG-SERVICE
36786482	GRET	SVC	8/17/2020	1972	RET ABN	UG-SERVICE
42584903	GRET	SVC	1/25/2024	1972	RET ABN	UG-SERVICE
42006056	GRET	SVC	8/14/2023	1972	RET ABN	UG-SERVICE
37887072	GRET	SVC	12/10/2020	1972	RET ABN	UG-SERVICE
36709891	GRET	SVC	8/5/2020	1972	RET ABN	UG-SERVICE
41411286	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
43295385	GRET	SVC	7/12/2024	1972	RET ABN	UG-SERVICE
43481241	GRET	SVC	10/23/2024	1972	RET ABN	UG-SERVICE
38041014	GRET	SVC	1/15/2021	1972	RET ABN	UG-SERVICE
41006872	GRET	SVC	12/7/2022	1972	RET ABN	UG-SERVICE
40308701	GRET	SVC	6/27/2022	1972	RET ABN	UG-SERVICE
42284433	GRET	SVC	10/26/2023	1972	RET ABN	UG-SERVICE
36820378	GRET	SVC	8/25/2020	1972	RET ABN	UG-SERVICE
38179976	GRET	SVC	4/28/2021	1972	RET ABN	UG-SERVICE
41614118	GRET	SVC	5/9/2023	1972	RET ABN	UG-SERVICE
43620359	GRET	SVC	9/23/2024	1972	RET ABN	UG-SERVICE
41411277	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
42566873	GRET	SVC	2/2/2024	1972	RET ABN	UG-SERVICE
36366705	GRET	SVC	6/16/2020	1972	RET ABN	UG-SERVICE
43946099	GRET	SVC	12/30/2024	1972	RET ABN	UG-SERVICE
38327111	GRET	SVC	4/8/2021	1972	RET ABN	UG-SERVICE
42970529	GRET	SVC	4/24/2024	1972	RET ABN	UG-SERVICE
43365789	GRET	SVC	12/19/2024	1972	RET ABN	UG-SERVICE
43063274	GRET	SVC	5/13/2024	1972	RET ABN	UG-SERVICE
42150870	GRET	SVC	10/13/2023	1972	RET ABN	UG-SERVICE
37898091	GRET	SVC	12/10/2020	1972	RET ABN	UG-SERVICE
43481250	GRET	SVC	9/10/2024	1972	RET ABN	UG-SERVICE
41258757	GRET	SVC	3/14/2023	1972	RET ABN	UG-SERVICE
38278785	GRET	SVC	4/28/2021	1972	RET ABN	UG-SERVICE
40953284	GRET	SVC	11/29/2022	1972	RET ABN	UG-SERVICE
40895627	GRET	SVC	11/7/2022	1972	RET ABN	UG-SERVICE
40916562	GRET	SVC	11/8/2022	1972	RET ABN	UG-SERVICE
40265392	GRET	SVC	6/7/2022	1972	RET ABN	UG-SERVICE
42166121	GRET	SVC	9/19/2023	1972	RET ABN	UG-SERVICE
43173863	GRET	SVC	7/17/2024	1972	RET ABN	UG-SERVICE
38427776	GRET	SVC	4/29/2021	1972	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42435908	GRET	SVC	9/19/2024	1972	RET ABN	UG-SERVICE
39570775	GRET	SVC	12/13/2021	1972	RET ABN	UG-SERVICE
40699291	GRET	SVC	9/29/2022	1972	RET ABN	UG-SERVICE
43217425	GRET	SVC	6/24/2024	1972	RET ABN	UG-SERVICE
37887986	GRET	SVC	12/9/2020	1972	RET ABN	UG-SERVICE
35868335	GRET	SVC	1/7/2020	1972	RET ABN	UG-SERVICE
39570921	GRET	SVC	12/13/2021	1972	RET ABN	UG-SERVICE
37036908	GRET	SVC	10/7/2020	1972	RET ABN	UG-SERVICE
38082511	GRET	SVC	2/2/2021	1972	RET ABN	UG-SERVICE
43480920	GRET	SVC	9/14/2024	1972	RET ABN	UG-SERVICE
41932791	GRET	SVC	9/18/2023	1972	RET ABN	UG-SERVICE
42227175	GRET	SVC	10/31/2023	1972	RET ABN	UG-SERVICE
38322528	GRET	SVC	11/3/2021	1972	RET ABN	UG-SERVICE
43120561	GRET	SVC	7/15/2024	1972	RET ABN	UG-SERVICE
42833359	GRET	SVC	7/23/2024	1972	RET ABN	UG-SERVICE
42579294	GRET	SVC	1/19/2024	1972	RET ABN	UG-SERVICE
41407749	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
41411271	GRET	SVC	4/2/2024	1972	RET ABN	UG-SERVICE
40514385	GRET	SVC	8/2/2022	1973	RET ABN	UG-SERVICE
42957430	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
43477543	GRET	SVC	8/26/2024	1973	RET ABN	UG-SERVICE
43346735	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42956758	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42227366	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42956467	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42098663	GRET	SVC	9/14/2023	1973	RET ABN	UG-SERVICE
42228021	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42957959	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41721134	GRET	SVC	6/8/2023	1973	RET ABN	UG-SERVICE
42487710	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42227957	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41277765	GRET	SVC	2/14/2023	1973	RET ABN	UG-SERVICE
41279351	GRET	SVC	3/15/2023	1973	RET ABN	UG-SERVICE
39257945	GRET	SVC	10/11/2021	1973	RET ABN	UG-SERVICE
42227364	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42957390	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42155783	GRET	SVC	9/27/2023	1973	RET ABN	UG-SERVICE
43554106	GRET	SVC	9/12/2024	1973	RET ABN	UG-SERVICE
38955723	GRET	SVC	8/22/2021	1973	RET ABN	UG-SERVICE
42487716	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
41922366	GRET	SVC	7/27/2023	1973	RET ABN	UG-SERVICE
43529736	GRET	SVC	12/6/2024	1973	RET ABN	UG-SERVICE
40581035	GRET	SVC	8/15/2022	1973	RET ABN	UG-SERVICE
40784117	GRET	SVC	10/10/2022	1973	RET ABN	UG-SERVICE
39544059	GRET	SVC	12/13/2021	1973	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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42227177	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
36839682	GRET	SVC	7/15/2020	1973	RET ABN	UG-SERVICE
42956332	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41273667	GRET	SVC	3/2/2023	1973	RET ABN	UG-SERVICE
42956845	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42767218	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
36192099	GRET	SVC	4/23/2020	1973	RET ABN	UG-SERVICE
42228023	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
38662181	GRET	SVC	6/24/2021	1973	RET ABN	UG-SERVICE
43245014	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42487724	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42227833	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
43480926	GRET	SVC	9/14/2024	1973	RET ABN	UG-SERVICE
42956477	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41722788	GRET	SVC	6/12/2023	1973	RET ABN	UG-SERVICE
42956759	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41277884	GRET	SVC	2/14/2023	1973	RET ABN	UG-SERVICE
42227319	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227945	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42509340	GRET	SVC	7/31/2024	1973	RET ABN	UG-SERVICE
42227302	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42530678	GRET	SVC	12/20/2023	1973	RET ABN	UG-SERVICE
41969077	GRET	SVC	8/1/2024	1973	RET ABN	UG-SERVICE
40528003	GRET	SVC	8/9/2022	1973	RET ABN	UG-SERVICE
42957332	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42227735	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227550	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
40140878	GRET	SVC	5/11/2022	1973	RET ABN	UG-SERVICE
42227317	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
38637830	GRET	SVC	7/23/2021	1973	RET ABN	UG-SERVICE
43613267	GRET	SVC	9/13/2024	1973	RET ABN	UG-SERVICE
41340689	GRET	SVC	3/18/2023	1973	RET ABN	UG-SERVICE
43480924	GRET	SVC	9/14/2024	1973	RET ABN	UG-SERVICE
43318481	GRET	SVC	8/15/2024	1973	RET ABN	UG-SERVICE
42227375	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
39970244	GRET	SVC	5/11/2022	1973	RET ABN	UG-SERVICE
42957394	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41316693	GRET	SVC	3/6/2023	1973	RET ABN	UG-SERVICE
42600438	GRET	SVC	1/25/2024	1973	RET ABN	UG-SERVICE
36003455	GRET	SVC	2/10/2020	1973	RET ABN	UG-SERVICE
42228028	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227949	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41414916	GRET	SVC	3/20/2023	1973	RET ABN	UG-SERVICE
36268686	GRET	SVC	5/4/2020	1973	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41027618	GRET	SVC	12/14/2022	1973	RET ABN	UG-SERVICE
41774608	GRET	SVC	6/23/2023	1973	RET ABN	UG-SERVICE
35934476	GRET	SVC	1/22/2020	1973	RET ABN	UG-SERVICE
39438659	GRET	SVC	11/18/2021	1973	RET ABN	UG-SERVICE
43423329	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42228027	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41273369	GRET	SVC	2/11/2023	1973	RET ABN	UG-SERVICE
39904817	GRET	SVC	4/11/2022	1973	RET ABN	UG-SERVICE
43244990	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41969340	GRET	SVC	7/30/2024	1973	RET ABN	UG-SERVICE
41414175	GRET	SVC	4/2/2024	1973	RET ABN	UG-SERVICE
38469920	GRET	SVC	5/10/2021	1973	RET ABN	UG-SERVICE
42283973	GRET	SVC	10/21/2023	1973	RET ABN	UG-SERVICE
42227316	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227315	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42957684	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
40372244	GRET	SVC	7/18/2022	1973	RET ABN	UG-SERVICE
42227303	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
39576175	GRET	SVC	7/8/2021	1973	RET ABN	UG-SERVICE
42227850	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
36208642	GRET	SVC	4/7/2021	1973	RET ABN	UG-SERVICE
41486042	GRET	SVC	4/11/2023	1973	RET ABN	UG-SERVICE
42956755	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
43245007	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
40338689	GRET	SVC	7/8/2022	1973	RET ABN	UG-SERVICE
42957391	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
36331192	GRET	SVC	5/15/2020	1973	RET ABN	UG-SERVICE
35936301	GRET	SVC	1/23/2020	1973	RET ABN	UG-SERVICE
36728962	GRET	SVC	8/3/2020	1973	RET ABN	UG-SERVICE
43365793	GRET	SVC	12/6/2024	1973	RET ABN	UG-SERVICE
42227737	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
36450481	GRET	SVC	6/16/2020	1973	RET ABN	UG-SERVICE
41273560	GRET	SVC	2/11/2023	1973	RET ABN	UG-SERVICE
42227955	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
40360389	GRET	SVC	6/22/2022	1973	RET ABN	UG-SERVICE
40309193	GRET	SVC	8/12/2022	1973	RET ABN	UG-SERVICE
42227176	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
36839691	GRET	SVC	7/15/2020	1973	RET ABN	UG-SERVICE
41101699	GRET	SVC	12/29/2022	1973	RET ABN	UG-SERVICE
42389920	GRET	SVC	11/18/2023	1973	RET ABN	UG-SERVICE
42956338	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42957337	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42020459	GRET	SVC	11/1/2023	1973	RET ABN	UG-SERVICE
43347824	GRET	SVC	7/22/2024	1973	RET ABN	UG-SERVICE
40015632	GRET	SVC	4/17/2022	1973	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43465891	GRET	SVC	8/16/2024	1973	RET ABN	UG-SERVICE
41242859	GRET	SVC	2/10/2023	1973	RET ABN	UG-SERVICE
40054754	GRET	SVC	12/23/2021	1973	RET ABN	UG-SERVICE
41241968	GRET	SVC	3/2/2023	1973	RET ABN	UG-SERVICE
36495864	GRET	SVC	7/7/2020	1973	RET ABN	UG-SERVICE
41211685	GRET	SVC	12/11/2023	1973	RET ABN	UG-SERVICE
42227736	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
39929212	GRET	SVC	3/10/2022	1973	RET ABN	UG-SERVICE
41963559	GRET	SVC	8/9/2023	1973	RET ABN	UG-SERVICE
42227360	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227314	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227551	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41246612	GRET	SVC	2/6/2023	1973	RET ABN	UG-SERVICE
41243052	GRET	SVC	3/17/2023	1973	RET ABN	UG-SERVICE
42520550	GRET	SVC	12/27/2023	1973	RET ABN	UG-SERVICE
37896433	GRET	SVC	12/23/2020	1973	RET ABN	UG-SERVICE
41774602	GRET	SVC	6/27/2023	1973	RET ABN	UG-SERVICE
42509250	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42227840	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227856	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
39211483	GRET	SVC	9/27/2021	1973	RET ABN	UG-SERVICE
41273574	GRET	SVC	2/19/2023	1973	RET ABN	UG-SERVICE
35926924	GRET	SVC	1/22/2020	1973	RET ABN	UG-SERVICE
43589203	GRET	SVC	9/24/2024	1973	RET ABN	UG-SERVICE
42228030	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41279002	GRET	SVC	2/16/2023	1973	RET ABN	UG-SERVICE
42956841	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42487344	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42487351	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
41247242	GRET	SVC	3/6/2023	1973	RET ABN	UG-SERVICE
38561880	GRET	SVC	4/17/2021	1973	RET ABN	UG-SERVICE
43155559	GRET	SVC	6/10/2024	1973	RET ABN	UG-SERVICE
42227365	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227844	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42957683	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
37094886	GRET	SVC	10/20/2020	1973	RET ABN	UG-SERVICE
41279350	GRET	SVC	2/16/2023	1973	RET ABN	UG-SERVICE
40671557	GRET	SVC	9/13/2022	1973	RET ABN	UG-SERVICE
40418545	GRET	SVC	7/13/2022	1973	RET ABN	UG-SERVICE
42227739	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42957389	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42227954	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
39293408	GRET	SVC	10/12/2021	1973	RET ABN	UG-SERVICE
42227300	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
43245107	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40756551	GRET	SVC	10/4/2022	1973	RET ABN	UG-SERVICE
42227853	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
43244992	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42487720	GRET	SVC	7/31/2024	1973	RET ABN	UG-SERVICE
42483428	GRET	SVC	4/15/2024	1973	RET ABN	UG-SERVICE
43347635	GRET	SVC	7/22/2024	1973	RET ABN	UG-SERVICE
41818864	GRET	SVC	7/21/2023	1973	RET ABN	UG-SERVICE
41247078	GRET	SVC	3/7/2023	1973	RET ABN	UG-SERVICE
42483430	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
38272431	GRET	SVC	2/25/2021	1973	RET ABN	UG-SERVICE
39728731	GRET	SVC	1/28/2022	1973	RET ABN	UG-SERVICE
42227721	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227953	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42846212	GRET	SVC	7/30/2024	1973	RET ABN	UG-SERVICE
41304277	GRET	SVC	9/18/2023	1973	RET ABN	UG-SERVICE
43480923	GRET	SVC	9/14/2024	1973	RET ABN	UG-SERVICE
36153326	GRET	SVC	3/19/2020	1973	RET ABN	UG-SERVICE
43122877	GRET	SVC	5/28/2024	1973	RET ABN	UG-SERVICE
41243177	GRET	SVC	2/10/2023	1973	RET ABN	UG-SERVICE
43506831	GRET	SVC	10/4/2024	1973	RET ABN	UG-SERVICE
38162884	GRET	SVC	2/22/2021	1973	RET ABN	UG-SERVICE
39665660	GRET	SVC	8/3/2022	1973	RET ABN	UG-SERVICE
43004209	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
35960589	GRET	SVC	1/28/2020	1973	RET ABN	UG-SERVICE
42228032	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41245808	GRET	SVC	2/11/2023	1973	RET ABN	UG-SERVICE
39570884	GRET	SVC	12/7/2021	1973	RET ABN	UG-SERVICE
41245801	GRET	SVC	2/11/2023	1973	RET ABN	UG-SERVICE
42551744	GRET	SVC	1/8/2024	1973	RET ABN	UG-SERVICE
43663930	GRET	SVC	10/7/2024	1973	RET ABN	UG-SERVICE
37094896	GRET	SVC	10/23/2020	1973	RET ABN	UG-SERVICE
43205044	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
40989015	GRET	SVC	11/29/2022	1973	RET ABN	UG-SERVICE
42487701	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42228025	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
38397396	GRET	SVC	4/20/2021	1973	RET ABN	UG-SERVICE
42956474	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42227942	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
38894836	GRET	SVC	8/13/2021	1973	RET ABN	UG-SERVICE
38427246	GRET	SVC	4/27/2021	1973	RET ABN	UG-SERVICE
42227720	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227841	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41277767	GRET	SVC	2/13/2023	1973	RET ABN	UG-SERVICE
36392249	GRET	SVC	6/4/2020	1973	RET ABN	UG-SERVICE
42227763	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42958052	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41273374	GRET	SVC	2/11/2023	1973	RET ABN	UG-SERVICE
41279262	GRET	SVC	2/14/2023	1973	RET ABN	UG-SERVICE
38561619	GRET	SVC	4/19/2021	1973	RET ABN	UG-SERVICE
43480925	GRET	SVC	9/14/2024	1973	RET ABN	UG-SERVICE
42380984	GRET	SVC	11/17/2023	1973	RET ABN	UG-SERVICE
41247074	GRET	SVC	3/7/2023	1973	RET ABN	UG-SERVICE
40388837	GRET	SVC	10/24/2022	1973	RET ABN	UG-SERVICE
42227843	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41179138	GRET	SVC	1/18/2023	1973	RET ABN	UG-SERVICE
42228029	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227664	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
38396306	GRET	SVC	4/20/2021	1973	RET ABN	UG-SERVICE
42627232	GRET	SVC	1/29/2024	1973	RET ABN	UG-SERVICE
40498641	GRET	SVC	7/28/2022	1973	RET ABN	UG-SERVICE
43005058	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
36960587	GRET	SVC	9/22/2020	1973	RET ABN	UG-SERVICE
41279156	GRET	SVC	2/16/2023	1973	RET ABN	UG-SERVICE
42958051	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
43245012	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42227178	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
36741661	GRET	SVC	8/5/2020	1973	RET ABN	UG-SERVICE
43705442	GRET	SVC	10/18/2024	1973	RET ABN	UG-SERVICE
42228022	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
39284203	GRET	SVC	10/12/2021	1973	RET ABN	UG-SERVICE
41273567	GRET	SVC	2/19/2023	1973	RET ABN	UG-SERVICE
39093693	GRET	SVC	9/7/2021	1973	RET ABN	UG-SERVICE
42227172	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41427448	GRET	SVC	3/21/2023	1973	RET ABN	UG-SERVICE
43974668	GRET	SVC	11/16/2024	1973	RET ABN	UG-SERVICE
43711580	GRET	SVC	11/22/2024	1973	RET ABN	UG-SERVICE
42228031	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42487754	GRET	SVC	7/31/2024	1973	RET ABN	UG-SERVICE
40558487	GRET	SVC	8/13/2022	1973	RET ABN	UG-SERVICE
41247244	GRET	SVC	3/6/2023	1973	RET ABN	UG-SERVICE
36363719	GRET	SVC	5/19/2020	1973	RET ABN	UG-SERVICE
38839899	GRET	SVC	7/26/2021	1973	RET ABN	UG-SERVICE
38156971	GRET	SVC	2/20/2021	1973	RET ABN	UG-SERVICE
41247068	GRET	SVC	2/8/2023	1973	RET ABN	UG-SERVICE
42227958	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42509251	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
40022949	GRET	SVC	4/11/2022	1973	RET ABN	UG-SERVICE
43282341	GRET	SVC	7/23/2024	1973	RET ABN	UG-SERVICE
41279141	GRET	SVC	3/24/2023	1973	RET ABN	UG-SERVICE
36876466	GRET	SVC	8/31/2020	1973	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41277772	GRET	SVC	3/1/2023	1973	RET ABN	UG-SERVICE
42956468	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42227306	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42833097	GRET	SVC	7/22/2024	1973	RET ABN	UG-SERVICE
43868699	GRET	SVC	11/26/2024	1973	RET ABN	UG-SERVICE
39901915	GRET	SVC	3/17/2022	1973	RET ABN	UG-SERVICE
42227956	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227845	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227760	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227944	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
43115657	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
41479996	GRET	SVC	4/6/2023	1973	RET ABN	UG-SERVICE
40054753	GRET	SVC	12/23/2021	1973	RET ABN	UG-SERVICE
41279540	GRET	SVC	3/8/2023	1973	RET ABN	UG-SERVICE
36007595	GRET	SVC	2/12/2020	1973	RET ABN	UG-SERVICE
42227959	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227679	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227761	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42679360	GRET	SVC	2/6/2024	1973	RET ABN	UG-SERVICE
42054745	GRET	SVC	8/29/2023	1973	RET ABN	UG-SERVICE
42487443	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42227834	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41245805	GRET	SVC	2/11/2023	1973	RET ABN	UG-SERVICE
43480921	GRET	SVC	9/14/2024	1973	RET ABN	UG-SERVICE
42227820	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42833358	GRET	SVC	7/23/2024	1973	RET ABN	UG-SERVICE
42227738	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41242858	GRET	SVC	3/21/2023	1973	RET ABN	UG-SERVICE
42227842	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42227943	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
41436540	GRET	SVC	3/29/2023	1973	RET ABN	UG-SERVICE
43145111	GRET	SVC	6/7/2024	1973	RET ABN	UG-SERVICE
43729863	GRET	SVC	10/22/2024	1973	RET ABN	UG-SERVICE
37973580	GRET	SVC	1/4/2021	1973	RET ABN	UG-SERVICE
41818653	GRET	SVC	7/27/2023	1973	RET ABN	UG-SERVICE
42670284	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42483434	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
40847419	GRET	SVC	10/24/2022	1973	RET ABN	UG-SERVICE
42487711	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
36260075	GRET	SVC	3/20/2020	1973	RET ABN	UG-SERVICE
42509258	GRET	SVC	7/18/2024	1973	RET ABN	UG-SERVICE
42227304	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
43613521	GRET	SVC	9/30/2024	1973	RET ABN	UG-SERVICE
42957338	GRET	SVC	9/19/2024	1973	RET ABN	UG-SERVICE
42227313	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43318350	GRET	SVC	8/5/2024	1973	RET ABN	UG-SERVICE
40683501	GRET	SVC	9/24/2022	1973	RET ABN	UG-SERVICE
42227835	GRET	SVC	10/31/2023	1973	RET ABN	UG-SERVICE
42509257	GRET	SVC	7/31/2024	1974	RET ABN	UG-SERVICE
42228034	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227732	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227549	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
37782096	GRET	SVC	11/25/2020	1974	RET ABN	UG-SERVICE
42227837	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43369052	GRET	SVC	8/19/2024	1974	RET ABN	UG-SERVICE
36194666	GRET	SVC	4/23/2020	1974	RET ABN	UG-SERVICE
41407766	GRET	SVC	10/19/2023	1974	RET ABN	UG-SERVICE
38301295	GRET	SVC	5/18/2021	1974	RET ABN	UG-SERVICE
39844903	GRET	SVC	2/28/2022	1974	RET ABN	UG-SERVICE
42227773	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
37216516	GRET	SVC	11/2/2020	1974	RET ABN	UG-SERVICE
39090763	GRET	SVC	9/21/2021	1974	RET ABN	UG-SERVICE
41533537	GRET	SVC	9/8/2023	1974	RET ABN	UG-SERVICE
40959691	GRET	SVC	11/21/2022	1974	RET ABN	UG-SERVICE
43667743	GRET	SVC	10/9/2024	1974	RET ABN	UG-SERVICE
42227821	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
36072400	GRET	SVC	6/2/2020	1974	RET ABN	UG-SERVICE
42227824	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227363	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
36036482	GRET	SVC	2/25/2020	1974	RET ABN	UG-SERVICE
42227307	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40801836	GRET	SVC	10/14/2022	1974	RET ABN	UG-SERVICE
42227839	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43380802	GRET	SVC	7/25/2024	1974	RET ABN	UG-SERVICE
42227830	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227669	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40595812	GRET	SVC	8/22/2022	1974	RET ABN	UG-SERVICE
43318352	GRET	SVC	11/6/2024	1974	RET ABN	UG-SERVICE
42227662	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40156382	GRET	SVC	5/3/2022	1974	RET ABN	UG-SERVICE
38453815	GRET	SVC	5/4/2021	1974	RET ABN	UG-SERVICE
41428615	GRET	SVC	3/22/2023	1974	RET ABN	UG-SERVICE
38014215	GRET	SVC	1/12/2021	1974	RET ABN	UG-SERVICE
42227545	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
38156953	GRET	SVC	7/30/2021	1974	RET ABN	UG-SERVICE
43711732	GRET	SVC	10/15/2024	1974	RET ABN	UG-SERVICE
42227731	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227671	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42956849	GRET	SVC	7/18/2024	1974	RET ABN	UG-SERVICE
39551371	GRET	SVC	12/16/2021	1974	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42227727	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
35888215	GRET	SVC	1/13/2020	1974	RET ABN	UG-SERVICE
38052297	GRET	SVC	1/25/2021	1974	RET ABN	UG-SERVICE
42227733	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227776	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43226784	GRET	SVC	6/25/2024	1974	RET ABN	UG-SERVICE
42915049	GRET	SVC	4/18/2024	1974	RET ABN	UG-SERVICE
42678881	GRET	SVC	2/5/2024	1974	RET ABN	UG-SERVICE
38934857	GRET	SVC	8/23/2021	1974	RET ABN	UG-SERVICE
42227318	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
36946724	GRET	SVC	9/14/2020	1974	RET ABN	UG-SERVICE
35941119	GRET	SVC	1/27/2020	1974	RET ABN	UG-SERVICE
42227769	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43592553	GRET	SVC	9/25/2024	1974	RET ABN	UG-SERVICE
43324302	GRET	SVC	8/2/2024	1974	RET ABN	UG-SERVICE
42227765	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42571143	GRET	SVC	2/21/2024	1974	RET ABN	UG-SERVICE
42284186	GRET	SVC	10/23/2023	1974	RET ABN	UG-SERVICE
42781675	GRET	SVC	3/6/2024	1974	RET ABN	UG-SERVICE
42227723	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
38287708	GRET	SVC	3/30/2021	1974	RET ABN	UG-SERVICE
41969806	GRET	SVC	8/7/2023	1974	RET ABN	UG-SERVICE
38881005	GRET	SVC	8/11/2021	1974	RET ABN	UG-SERVICE
42227722	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
37957971	GRET	SVC	12/27/2020	1974	RET ABN	UG-SERVICE
38042123	GRET	SVC	1/25/2021	1974	RET ABN	UG-SERVICE
42227855	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227728	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43674680	GRET	SVC	10/11/2024	1974	RET ABN	UG-SERVICE
41917199	GRET	SVC	7/28/2023	1974	RET ABN	UG-SERVICE
39436536	GRET	SVC	12/4/2021	1974	RET ABN	UG-SERVICE
42227730	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42055908	GRET	SVC	8/29/2023	1974	RET ABN	UG-SERVICE
39388355	GRET	SVC	11/5/2021	1974	RET ABN	UG-SERVICE
37811150	GRET	SVC	12/4/2020	1974	RET ABN	UG-SERVICE
38975815	GRET	SVC	8/31/2021	1974	RET ABN	UG-SERVICE
37891114	GRET	SVC	12/8/2020	1974	RET ABN	UG-SERVICE
42227557	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227854	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
35861892	GRET	SVC	1/8/2020	1974	RET ABN	UG-SERVICE
38217834	GRET	SVC	3/10/2021	1974	RET ABN	UG-SERVICE
42227374	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227554	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227822	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
36736359	GRET	SVC	8/6/2020	1974	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42227829	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227310	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
35958586	GRET	SVC	1/28/2020	1974	RET ABN	UG-SERVICE
42227377	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40113542	GRET	SVC	5/4/2022	1974	RET ABN	UG-SERVICE
37053180	GRET	SVC	10/12/2020	1974	RET ABN	UG-SERVICE
42549252	GRET	SVC	1/8/2024	1974	RET ABN	UG-SERVICE
43030227	GRET	SVC	5/15/2024	1974	RET ABN	UG-SERVICE
42227729	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227376	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227556	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227548	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227940	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40819779	GRET	SVC	10/18/2022	1974	RET ABN	UG-SERVICE
42227543	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43464646	GRET	SVC	8/20/2024	1974	RET ABN	UG-SERVICE
38447998	GRET	SVC	5/3/2021	1974	RET ABN	UG-SERVICE
42227768	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
36992975	GRET	SVC	9/29/2020	1974	RET ABN	UG-SERVICE
39489548	GRET	SVC	12/11/2021	1974	RET ABN	UG-SERVICE
42227674	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
35316596	GRET	SVC	1/22/2021	1974	RET ABN	UG-SERVICE
42227725	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
41243542	GRET	SVC	2/7/2023	1974	RET ABN	UG-SERVICE
42227309	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
41922368	GRET	SVC	7/27/2023	1974	RET ABN	UG-SERVICE
42227777	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227672	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227670	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227673	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
41834898	GRET	SVC	7/10/2023	1974	RET ABN	UG-SERVICE
42227676	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43598257	GRET	SVC	9/23/2024	1974	RET ABN	UG-SERVICE
36315324	GRET	SVC	5/12/2020	1974	RET ABN	UG-SERVICE
40724321	GRET	SVC	9/20/2022	1974	RET ABN	UG-SERVICE
42227858	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227774	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43282149	GRET	SVC	12/2/2024	1974	RET ABN	UG-SERVICE
42227851	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43515343	GRET	SVC	9/5/2024	1974	RET ABN	UG-SERVICE
36835404	GRET	SVC	8/26/2020	1974	RET ABN	UG-SERVICE
42227724	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
38499443	GRET	SVC	4/2/2021	1974	RET ABN	UG-SERVICE
43608047	GRET	SVC	10/1/2024	1974	RET ABN	UG-SERVICE
42227779	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42670283	GRET	SVC	9/19/2024	1974	RET ABN	UG-SERVICE
42227827	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227726	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
39803711	GRET	SVC	2/16/2022	1974	RET ABN	UG-SERVICE
36471396	GRET	SVC	7/11/2020	1974	RET ABN	UG-SERVICE
42227663	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227675	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
38324623	GRET	SVC	4/6/2021	1974	RET ABN	UG-SERVICE
43282145	GRET	SVC	12/2/2024	1974	RET ABN	UG-SERVICE
43862285	GRET	SVC	11/22/2024	1974	RET ABN	UG-SERVICE
42227859	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227771	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
38122752	GRET	SVC	2/12/2021	1974	RET ABN	UG-SERVICE
37094277	GRET	SVC	10/20/2020	1974	RET ABN	UG-SERVICE
42227546	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227775	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227941	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43963064	GRET	SVC	12/19/2024	1974	RET ABN	UG-SERVICE
42227553	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40254567	GRET	SVC	9/12/2022	1974	RET ABN	UG-SERVICE
42227836	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40091749	GRET	SVC	5/13/2022	1974	RET ABN	UG-SERVICE
37041461	GRET	SVC	10/8/2020	1974	RET ABN	UG-SERVICE
42227362	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
36031274	GRET	SVC	2/17/2020	1974	RET ABN	UG-SERVICE
42227857	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
35919174	GRET	SVC	2/19/2020	1974	RET ABN	UG-SERVICE
42227778	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227828	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227823	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
41706827	GRET	SVC	8/21/2023	1974	RET ABN	UG-SERVICE
43205303	GRET	SVC	6/15/2024	1974	RET ABN	UG-SERVICE
42227552	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227174	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227734	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43530074	GRET	SVC	9/6/2024	1974	RET ABN	UG-SERVICE
42227544	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227825	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227555	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
35945529	GRET	SVC	1/26/2020	1974	RET ABN	UG-SERVICE
39233301	GRET	SVC	9/30/2021	1974	RET ABN	UG-SERVICE
42227308	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227838	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40754061	GRET	SVC	9/28/2022	1974	RET ABN	UG-SERVICE
42227678	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43109290	GRET	SVC	5/30/2024	1974	RET ABN	UG-SERVICE
42227667	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227831	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227179	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227311	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
40900806	GRET	SVC	12/6/2022	1974	RET ABN	UG-SERVICE
40357997	GRET	SVC	8/2/2022	1974	RET ABN	UG-SERVICE
42227666	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
38640384	GRET	SVC	6/21/2021	1974	RET ABN	UG-SERVICE
42227764	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
36730703	GRET	SVC	9/8/2020	1974	RET ABN	UG-SERVICE
40572525	GRET	SVC	8/15/2022	1974	RET ABN	UG-SERVICE
42828610	GRET	SVC	3/18/2024	1974	RET ABN	UG-SERVICE
42227173	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227767	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
43327222	GRET	SVC	7/30/2024	1974	RET ABN	UG-SERVICE
38638881	GRET	SVC	8/2/2021	1974	RET ABN	UG-SERVICE
42227661	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42227660	GRET	SVC	10/31/2023	1974	RET ABN	UG-SERVICE
42899349	GRET	SVC	4/15/2024	1974	RET ABN	UG-SERVICE
41888298	GRET	SVC	7/18/2023	1974	RET ABN	UG-SERVICE
42177761	GRET	SVC	11/16/2023	1975	RET ABN	UG-SERVICE
37869004	GRET	SVC	12/2/2020	1975	RET ABN	UG-SERVICE
40751251	GRET	SVC	9/30/2022	1975	RET ABN	UG-SERVICE
41279008	GRET	SVC	2/15/2023	1975	RET ABN	UG-SERVICE
43448530	GRET	SVC	12/11/2024	1975	RET ABN	UG-SERVICE
38591974	GRET	SVC	4/20/2021	1975	RET ABN	UG-SERVICE
39835902	GRET	SVC	2/28/2022	1975	RET ABN	UG-SERVICE
40078415	GRET	SVC	4/27/2022	1975	RET ABN	UG-SERVICE
38571057	GRET	SVC	6/11/2021	1975	RET ABN	UG-SERVICE
39550151	GRET	SVC	12/17/2021	1975	RET ABN	UG-SERVICE
43867068	GRET	SVC	11/25/2024	1975	RET ABN	UG-SERVICE
43631731	GRET	SVC	9/30/2024	1975	RET ABN	UG-SERVICE
36165982	GRET	SVC	3/24/2020	1975	RET ABN	UG-SERVICE
42584864	GRET	SVC	1/22/2024	1975	RET ABN	UG-SERVICE
41426040	GRET	SVC	3/22/2023	1975	RET ABN	UG-SERVICE
41528449	GRET	SVC	4/26/2023	1975	RET ABN	UG-SERVICE
38053254	GRET	SVC	1/25/2021	1975	RET ABN	UG-SERVICE
36029864	GRET	SVC	2/18/2020	1975	RET ABN	UG-SERVICE
40507365	GRET	SVC	7/30/2022	1975	RET ABN	UG-SERVICE
36298477	GRET	SVC	4/8/2020	1975	RET ABN	UG-SERVICE
40062912	GRET	SVC	4/25/2022	1975	RET ABN	UG-SERVICE
39824976	GRET	SVC	2/23/2022	1975	RET ABN	UG-SERVICE
38192814	GRET	SVC	3/3/2021	1975	RET ABN	UG-SERVICE
38886010	GRET	SVC	8/9/2021	1975	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36882321	GRET	SVC	9/1/2020	1975	RET ABN	UG-SERVICE
41283333	GRET	SVC	2/16/2023	1975	RET ABN	UG-SERVICE
43905665	GRET	SVC	12/4/2024	1975	RET ABN	UG-SERVICE
42584534	GRET	SVC	1/22/2024	1975	RET ABN	UG-SERVICE
42052653	GRET	SVC	8/31/2023	1975	RET ABN	UG-SERVICE
41162248	GRET	SVC	1/12/2023	1975	RET ABN	UG-SERVICE
42760336	GRET	SVC	8/1/2024	1975	RET ABN	UG-SERVICE
41277769	GRET	SVC	2/14/2023	1975	RET ABN	UG-SERVICE
41498695	GRET	SVC	4/21/2023	1975	RET ABN	UG-SERVICE
38582326	GRET	SVC	6/15/2021	1975	RET ABN	UG-SERVICE
41279152	GRET	SVC	2/15/2023	1975	RET ABN	UG-SERVICE
36119482	GRET	SVC	11/5/2020	1975	RET ABN	UG-SERVICE
37926339	GRET	SVC	12/13/2020	1975	RET ABN	UG-SERVICE
40561480	GRET	SVC	8/15/2022	1975	RET ABN	UG-SERVICE
43228186	GRET	SVC	9/19/2024	1975	RET ABN	UG-SERVICE
40669708	GRET	SVC	10/22/2022	1975	RET ABN	UG-SERVICE
40328415	GRET	SVC	8/2/2022	1975	RET ABN	UG-SERVICE
43820162	GRET	SVC	11/12/2024	1975	RET ABN	UG-SERVICE
43473374	GRET	SVC	9/7/2024	1975	RET ABN	UG-SERVICE
41283327	GRET	SVC	2/16/2023	1975	RET ABN	UG-SERVICE
37064875	GRET	SVC	10/12/2020	1975	RET ABN	UG-SERVICE
37099276	GRET	SVC	9/9/2020	1975	RET ABN	UG-SERVICE
43240063	GRET	SVC	6/30/2024	1975	RET ABN	UG-SERVICE
41342698	GRET	SVC	3/7/2023	1975	RET ABN	UG-SERVICE
43743877	GRET	SVC	10/23/2024	1975	RET ABN	UG-SERVICE
40352832	GRET	SVC	6/28/2022	1975	RET ABN	UG-SERVICE
41279013	GRET	SVC	2/15/2023	1975	RET ABN	UG-SERVICE
36701068	GRET	SVC	7/28/2020	1975	RET ABN	UG-SERVICE
39560483	GRET	SVC	12/20/2021	1975	RET ABN	UG-SERVICE
42252699	GRET	SVC	10/20/2023	1975	RET ABN	UG-SERVICE
41497631	GRET	SVC	4/21/2023	1975	RET ABN	UG-SERVICE
41033159	GRET	SVC	12/15/2022	1975	RET ABN	UG-SERVICE
39657981	GRET	SVC	2/10/2022	1975	RET ABN	UG-SERVICE
40431528	GRET	SVC	7/14/2022	1975	RET ABN	UG-SERVICE
42956743	GRET	SVC	9/19/2024	1975	RET ABN	UG-SERVICE
41646104	GRET	SVC	5/17/2023	1975	RET ABN	UG-SERVICE
36882136	GRET	SVC	9/1/2020	1975	RET ABN	UG-SERVICE
39281140	GRET	SVC	10/7/2021	1975	RET ABN	UG-SERVICE
36735967	GRET	SVC	8/3/2020	1975	RET ABN	UG-SERVICE
40218720	GRET	SVC	6/7/2022	1975	RET ABN	UG-SERVICE
38930274	GRET	SVC	8/23/2021	1975	RET ABN	UG-SERVICE
41906711	GRET	SVC	7/24/2023	1975	RET ABN	UG-SERVICE
39619526	GRET	SVC	1/3/2022	1975	RET ABN	UG-SERVICE
39251887	GRET	SVC	10/6/2021	1975	RET ABN	UG-SERVICE
40431115	GRET	SVC	7/15/2022	1975	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43929086	GRET	SVC	12/13/2024	1975	RET ABN	UG-SERVICE
37926322	GRET	SVC	12/16/2020	1975	RET ABN	UG-SERVICE
43309760	GRET	SVC	7/13/2024	1975	RET ABN	UG-SERVICE
38884105	GRET	SVC	8/18/2021	1975	RET ABN	UG-SERVICE
41423574	GRET	SVC	10/18/2023	1975	RET ABN	UG-SERVICE
38749947	GRET	SVC	7/22/2021	1975	RET ABN	UG-SERVICE
41636672	GRET	SVC	5/14/2023	1975	RET ABN	UG-SERVICE
42834267	GRET	SVC	7/23/2024	1975	RET ABN	UG-SERVICE
36580064	GRET	SVC	7/6/2020	1975	RET ABN	UG-SERVICE
36040618	GRET	SVC	2/19/2020	1975	RET ABN	UG-SERVICE
41580112	GRET	SVC	5/3/2023	1975	RET ABN	UG-SERVICE
36662570	GRET	SVC	7/20/2020	1975	RET ABN	UG-SERVICE
40497358	GRET	SVC	7/26/2022	1975	RET ABN	UG-SERVICE
39960894	GRET	SVC	5/25/2022	1975	RET ABN	UG-SERVICE
40327034	GRET	SVC	6/20/2022	1975	RET ABN	UG-SERVICE
37875936	GRET	SVC	12/3/2020	1975	RET ABN	UG-SERVICE
42584519	GRET	SVC	1/22/2024	1975	RET ABN	UG-SERVICE
41182816	GRET	SVC	1/19/2023	1975	RET ABN	UG-SERVICE
41287921	GRET	SVC	3/16/2023	1975	RET ABN	UG-SERVICE
41411231	GRET	SVC	4/2/2024	1975	RET ABN	UG-SERVICE
42379497	GRET	SVC	11/28/2023	1975	RET ABN	UG-SERVICE
41445566	GRET	SVC	3/28/2023	1975	RET ABN	UG-SERVICE
40900676	GRET	SVC	11/12/2022	1975	RET ABN	UG-SERVICE
40062210	GRET	SVC	5/2/2022	1975	RET ABN	UG-SERVICE
38212855	GRET	SVC	3/7/2021	1975	RET ABN	UG-SERVICE
38534582	GRET	SVC	5/25/2021	1975	RET ABN	UG-SERVICE
43469767	GRET	SVC	8/21/2024	1975	RET ABN	UG-SERVICE
41606960	GRET	SVC	5/8/2023	1975	RET ABN	UG-SERVICE
38200998	GRET	SVC	3/6/2021	1975	RET ABN	UG-SERVICE
41567772	GRET	SVC	5/2/2023	1975	RET ABN	UG-SERVICE
41467224	GRET	SVC	4/27/2023	1975	RET ABN	UG-SERVICE
41316863	GRET	SVC	2/28/2023	1975	RET ABN	UG-SERVICE
39236000	GRET	SVC	9/30/2021	1975	RET ABN	UG-SERVICE
40419741	GRET	SVC	8/31/2022	1975	RET ABN	UG-SERVICE
38160985	GRET	SVC	2/27/2021	1975	RET ABN	UG-SERVICE
42509254	GRET	SVC	7/18/2024	1975	RET ABN	UG-SERVICE
38455304	GRET	SVC	5/7/2021	1975	RET ABN	UG-SERVICE
38492184	GRET	SVC	5/13/2021	1975	RET ABN	UG-SERVICE
38865047	GRET	SVC	8/4/2021	1975	RET ABN	UG-SERVICE
39395577	GRET	SVC	11/23/2021	1975	RET ABN	UG-SERVICE
37067280	GRET	SVC	10/27/2020	1976	RET ABN	UG-SERVICE
42530674	GRET	SVC	12/20/2023	1976	RET ABN	UG-SERVICE
40761856	GRET	SVC	10/18/2022	1976	RET ABN	UG-SERVICE
42626212	GRET	SVC	1/29/2024	1976	RET ABN	UG-SERVICE
36980370	GRET	SVC	9/23/2020	1976	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40990267	GRET	SVC	11/17/2022	1976	RET ABN	UG-SERVICE
41450915	GRET	SVC	3/29/2023	1976	RET ABN	UG-SERVICE
38397906	GRET	SVC	4/26/2021	1976	RET ABN	UG-SERVICE
41520905	GRET	SVC	4/27/2023	1976	RET ABN	UG-SERVICE
42509255	GRET	SVC	7/18/2024	1976	RET ABN	UG-SERVICE
41482053	GRET	SVC	4/9/2023	1976	RET ABN	UG-SERVICE
39547480	GRET	SVC	12/12/2021	1976	RET ABN	UG-SERVICE
42004203	GRET	SVC	8/13/2023	1976	RET ABN	UG-SERVICE
42744659	GRET	SVC	2/17/2024	1976	RET ABN	UG-SERVICE
37936716	GRET	SVC	12/20/2020	1976	RET ABN	UG-SERVICE
38744414	GRET	SVC	7/12/2021	1976	RET ABN	UG-SERVICE
37971323	GRET	SVC	12/28/2020	1976	RET ABN	UG-SERVICE
40656087	GRET	SVC	8/30/2022	1976	RET ABN	UG-SERVICE
38601905	GRET	SVC	7/7/2021	1976	RET ABN	UG-SERVICE
36672285	GRET	SVC	7/22/2020	1976	RET ABN	UG-SERVICE
35151335	GRET	SVC	1/6/2020	1976	RET ABN	UG-SERVICE
41860024	GRET	SVC	7/8/2023	1976	RET ABN	UG-SERVICE
39369426	GRET	SVC	11/1/2021	1976	RET ABN	UG-SERVICE
41041907	GRET	SVC	11/1/2022	1976	RET ABN	UG-SERVICE
36656230	GRET	SVC	7/21/2020	1976	RET ABN	UG-SERVICE
37142284	GRET	SVC	10/29/2020	1976	RET ABN	UG-SERVICE
40512849	GRET	SVC	8/5/2022	1976	RET ABN	UG-SERVICE
37926328	GRET	SVC	12/13/2020	1976	RET ABN	UG-SERVICE
36041151	GRET	SVC	2/17/2020	1976	RET ABN	UG-SERVICE
38707020	GRET	SVC	8/3/2021	1976	RET ABN	UG-SERVICE
42391940	GRET	SVC	11/20/2023	1976	RET ABN	UG-SERVICE
37952658	GRET	SVC	12/22/2020	1976	RET ABN	UG-SERVICE
39515604	GRET	SVC	12/23/2021	1976	RET ABN	UG-SERVICE
39143438	GRET	SVC	9/20/2021	1976	RET ABN	UG-SERVICE
36178247	GRET	SVC	3/2/2020	1976	RET ABN	UG-SERVICE
38441449	GRET	SVC	1/3/2022	1976	RET ABN	UG-SERVICE
40963331	GRET	SVC	11/19/2022	1976	RET ABN	UG-SERVICE
39580230	GRET	SVC	12/27/2021	1976	RET ABN	UG-SERVICE
41759598	GRET	SVC	7/13/2023	1976	RET ABN	UG-SERVICE
38098602	GRET	SVC	2/8/2021	1976	RET ABN	UG-SERVICE
42612164	GRET	SVC	1/29/2024	1976	RET ABN	UG-SERVICE
40488326	GRET	SVC	8/11/2022	1976	RET ABN	UG-SERVICE
41411294	GRET	SVC	4/2/2024	1976	RET ABN	UG-SERVICE
43694923	GRET	SVC	10/24/2024	1976	RET ABN	UG-SERVICE
42115195	GRET	SVC	9/11/2023	1976	RET ABN	UG-SERVICE
43582448	GRET	SVC	9/16/2024	1976	RET ABN	UG-SERVICE
42555015	GRET	SVC	1/6/2024	1976	RET ABN	UG-SERVICE
40492798	GRET	SVC	8/3/2022	1976	RET ABN	UG-SERVICE
43624063	GRET	SVC	9/27/2024	1976	RET ABN	UG-SERVICE
41439585	GRET	SVC	3/29/2023	1976	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
37214711	GRET	SVC	12/8/2020	1976	RET ABN	UG-SERVICE
42221082	GRET	SVC	10/11/2023	1976	RET ABN	UG-SERVICE
36612956	GRET	SVC	7/13/2020	1976	RET ABN	UG-SERVICE
42107582	GRET	SVC	9/12/2023	1976	RET ABN	UG-SERVICE
37998238	GRET	SVC	1/11/2021	1976	RET ABN	UG-SERVICE
41424229	GRET	SVC	6/21/2023	1976	RET ABN	UG-SERVICE
37674075	GRET	SVC	12/29/2020	1976	RET ABN	UG-SERVICE
38140474	GRET	SVC	2/18/2021	1976	RET ABN	UG-SERVICE
36200170	GRET	SVC	5/6/2020	1976	RET ABN	UG-SERVICE
35986883	GRET	SVC	2/17/2020	1976	RET ABN	UG-SERVICE
42794394	GRET	SVC	3/4/2024	1976	RET ABN	UG-SERVICE
43364930	GRET	SVC	10/15/2024	1976	RET ABN	UG-SERVICE
36309007	GRET	SVC	5/12/2020	1976	RET ABN	UG-SERVICE
42584912	GRET	SVC	1/22/2024	1976	RET ABN	UG-SERVICE
41979984	GRET	SVC	8/18/2023	1976	RET ABN	UG-SERVICE
41411766	GRET	SVC	4/2/2024	1976	RET ABN	UG-SERVICE
36883686	GRET	SVC	8/30/2020	1976	RET ABN	UG-SERVICE
38441378	GRET	SVC	1/6/2022	1976	RET ABN	UG-SERVICE
39242981	GRET	SVC	9/29/2021	1976	RET ABN	UG-SERVICE
39660249	GRET	SVC	1/28/2022	1976	RET ABN	UG-SERVICE
43758690	GRET	SVC	11/7/2024	1977	RET ABN	UG-SERVICE
43923634	GRET	SVC	12/11/2024	1977	RET ABN	UG-SERVICE
40492802	GRET	SVC	7/26/2022	1977	RET ABN	UG-SERVICE
43767472	GRET	SVC	10/28/2024	1977	RET ABN	UG-SERVICE
43107587	GRET	SVC	5/28/2024	1977	RET ABN	UG-SERVICE
43976845	GRET	SVC	11/15/2024	1977	RET ABN	UG-SERVICE
42026562	GRET	SVC	8/24/2023	1977	RET ABN	UG-SERVICE
42950784	GRET	SVC	4/26/2024	1977	RET ABN	UG-SERVICE
40879585	GRET	SVC	11/11/2022	1977	RET ABN	UG-SERVICE
41273664	GRET	SVC	3/15/2023	1977	RET ABN	UG-SERVICE
42590191	GRET	SVC	1/24/2024	1977	RET ABN	UG-SERVICE
43909859	GRET	SVC	12/2/2024	1977	RET ABN	UG-SERVICE
42567332	GRET	SVC	1/17/2024	1977	RET ABN	UG-SERVICE
39552045	GRET	SVC	12/3/2021	1977	RET ABN	UG-SERVICE
40675412	GRET	SVC	11/15/2022	1977	RET ABN	UG-SERVICE
38637747	GRET	SVC	6/16/2021	1977	RET ABN	UG-SERVICE
43800154	GRET	SVC	11/12/2024	1977	RET ABN	UG-SERVICE
37886408	GRET	SVC	12/5/2020	1977	RET ABN	UG-SERVICE
38181886	GRET	SVC	3/2/2021	1977	RET ABN	UG-SERVICE
37052904	GRET	SVC	10/14/2020	1977	RET ABN	UG-SERVICE
36918090	GRET	SVC	9/15/2020	1977	RET ABN	UG-SERVICE
37887387	GRET	SVC	12/8/2020	1977	RET ABN	UG-SERVICE
38364546	GRET	SVC	4/12/2021	1977	RET ABN	UG-SERVICE
42837425	GRET	SVC	3/20/2024	1977	RET ABN	UG-SERVICE
36146405	GRET	SVC	3/16/2020	1977	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42949532	GRET	SVC	4/26/2024	1977	RET ABN	UG-SERVICE
35844806	GRET	SVC	1/2/2020	1977	RET ABN	UG-SERVICE
41331746	GRET	SVC	3/1/2023	1977	RET ABN	UG-SERVICE
38089364	GRET	SVC	1/29/2021	1977	RET ABN	UG-SERVICE
38034709	GRET	SVC	1/19/2021	1977	RET ABN	UG-SERVICE
38352723	GRET	SVC	7/27/2021	1977	RET ABN	UG-SERVICE
43654659	GRET	SVC	10/18/2024	1977	RET ABN	UG-SERVICE
36472441	GRET	SVC	6/22/2020	1977	RET ABN	UG-SERVICE
40395627	GRET	SVC	6/30/2022	1977	RET ABN	UG-SERVICE
38171193	GRET	SVC	2/26/2021	1977	RET ABN	UG-SERVICE
41556508	GRET	SVC	4/25/2023	1977	RET ABN	UG-SERVICE
36566413	GRET	SVC	7/1/2020	1977	RET ABN	UG-SERVICE
40561488	GRET	SVC	8/27/2022	1977	RET ABN	UG-SERVICE
41099636	GRET	SVC	12/30/2022	1977	RET ABN	UG-SERVICE
36915179	GRET	SVC	7/30/2020	1977	RET ABN	UG-SERVICE
40702313	GRET	SVC	9/14/2022	1977	RET ABN	UG-SERVICE
38268372	GRET	SVC	3/23/2021	1977	RET ABN	UG-SERVICE
37926236	GRET	SVC	12/13/2020	1977	RET ABN	UG-SERVICE
41411229	GRET	SVC	4/2/2024	1977	RET ABN	UG-SERVICE
36727255	GRET	SVC	8/4/2020	1977	RET ABN	UG-SERVICE
39552046	GRET	SVC	12/29/2021	1977	RET ABN	UG-SERVICE
42427484	GRET	SVC	9/19/2024	1977	RET ABN	UG-SERVICE
40692811	GRET	SVC	9/30/2022	1977	RET ABN	UG-SERVICE
41411763	GRET	SVC	4/2/2024	1977	RET ABN	UG-SERVICE
38107383	GRET	SVC	2/8/2021	1977	RET ABN	UG-SERVICE
41084050	GRET	SVC	12/21/2022	1977	RET ABN	UG-SERVICE
42277299	GRET	SVC	10/24/2023	1977	RET ABN	UG-SERVICE
43442180	GRET	SVC	8/14/2024	1977	RET ABN	UG-SERVICE
38352929	GRET	SVC	2/17/2023	1977	RET ABN	UG-SERVICE
36345939	GRET	SVC	5/18/2020	1977	RET ABN	UG-SERVICE
42650726	GRET	SVC	1/29/2024	1977	RET ABN	UG-SERVICE
39492215	GRET	SVC	12/7/2021	1977	RET ABN	UG-SERVICE
42020567	GRET	SVC	8/23/2023	1977	RET ABN	UG-SERVICE
42461273	GRET	SVC	12/14/2023	1977	RET ABN	UG-SERVICE
41242715	GRET	SVC	2/4/2023	1977	RET ABN	UG-SERVICE
43650299	GRET	SVC	10/2/2024	1977	RET ABN	UG-SERVICE
39299100	GRET	SVC	10/14/2021	1977	RET ABN	UG-SERVICE
37642997	GRET	SVC	11/18/2020	1977	RET ABN	UG-SERVICE
36202016	GRET	SVC	4/23/2020	1977	RET ABN	UG-SERVICE
43525354	GRET	SVC	10/15/2024	1977	RET ABN	UG-SERVICE
41859267	GRET	SVC	7/10/2023	1977	RET ABN	UG-SERVICE
42065386	GRET	SVC	9/7/2023	1977	RET ABN	UG-SERVICE
36451833	GRET	SVC	6/16/2020	1977	RET ABN	UG-SERVICE
38148103	GRET	SVC	2/21/2021	1977	RET ABN	UG-SERVICE
40708496	GRET	SVC	9/16/2022	1977	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43281289	GRET	SVC	7/9/2024	1977	RET ABN	UG-SERVICE
43007247	GRET	SVC	4/29/2024	1977	RET ABN	UG-SERVICE
42025488	GRET	SVC	8/22/2023	1977	RET ABN	UG-SERVICE
35151134	GRET	SVC	1/6/2020	1977	RET ABN	UG-SERVICE
41009656	GRET	SVC	12/5/2022	1977	RET ABN	UG-SERVICE
38845329	GRET	SVC	8/2/2021	1977	RET ABN	UG-SERVICE
40996102	GRET	SVC	12/28/2022	1977	RET ABN	UG-SERVICE
36185404	GRET	SVC	5/28/2020	1977	RET ABN	UG-SERVICE
38441174	GRET	SVC	1/3/2022	1977	RET ABN	UG-SERVICE
38441399	GRET	SVC	12/22/2021	1977	RET ABN	UG-SERVICE
41834503	GRET	SVC	7/21/2023	1977	RET ABN	UG-SERVICE
42903278	GRET	SVC	4/9/2024	1978	RET ABN	UG-SERVICE
35872099	GRET	SVC	1/7/2020	1978	RET ABN	UG-SERVICE
39518355	GRET	SVC	1/3/2022	1978	RET ABN	UG-SERVICE
43086904	GRET	SVC	8/5/2024	1978	RET ABN	UG-SERVICE
41051001	GRET	SVC	6/16/2023	1978	RET ABN	UG-SERVICE
43876310	GRET	SVC	11/27/2024	1978	RET ABN	UG-SERVICE
37149839	GRET	SVC	10/29/2020	1978	RET ABN	UG-SERVICE
43151675	GRET	SVC	7/18/2024	1978	RET ABN	UG-SERVICE
41182813	GRET	SVC	1/18/2023	1978	RET ABN	UG-SERVICE
41482107	GRET	SVC	4/11/2023	1978	RET ABN	UG-SERVICE
39705070	GRET	SVC	2/5/2024	1978	RET ABN	UG-SERVICE
41330349	GRET	SVC	3/3/2023	1978	RET ABN	UG-SERVICE
39599855	GRET	SVC	1/12/2022	1978	RET ABN	UG-SERVICE
41424707	GRET	SVC	10/18/2023	1978	RET ABN	UG-SERVICE
38407205	GRET	SVC	3/17/2021	1978	RET ABN	UG-SERVICE
36197812	GRET	SVC	4/22/2020	1978	RET ABN	UG-SERVICE
37415010	GRET	SVC	11/9/2020	1978	RET ABN	UG-SERVICE
39532048	GRET	SVC	12/14/2021	1978	RET ABN	UG-SERVICE
38278377	GRET	SVC	4/28/2021	1978	RET ABN	UG-SERVICE
39705136	GRET	SVC	2/6/2024	1978	RET ABN	UG-SERVICE
39983692	GRET	SVC	3/25/2022	1978	RET ABN	UG-SERVICE
36218763	GRET	SVC	4/24/2020	1978	RET ABN	UG-SERVICE
42707518	GRET	SVC	3/13/2024	1978	RET ABN	UG-SERVICE
36148266	GRET	SVC	3/17/2020	1978	RET ABN	UG-SERVICE
41860453	GRET	SVC	7/12/2023	1978	RET ABN	UG-SERVICE
41050845	GRET	SVC	6/16/2023	1978	RET ABN	UG-SERVICE
40753033	GRET	SVC	10/10/2022	1978	RET ABN	UG-SERVICE
38621996	GRET	SVC	6/15/2021	1978	RET ABN	UG-SERVICE
42021084	GRET	SVC	8/21/2023	1978	RET ABN	UG-SERVICE
43612739	GRET	SVC	9/24/2024	1978	RET ABN	UG-SERVICE
41213038	GRET	SVC	1/31/2023	1978	RET ABN	UG-SERVICE
39745751	GRET	SVC	2/11/2022	1978	RET ABN	UG-SERVICE
40371186	GRET	SVC	7/6/2022	1978	RET ABN	UG-SERVICE
43543531	GRET	SVC	10/1/2024	1978	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43370684	GRET	SVC	11/9/2024	1978	RET ABN	UG-SERVICE
43005602	GRET	SVC	5/9/2024	1978	RET ABN	UG-SERVICE
37809859	GRET	SVC	11/24/2020	1978	RET ABN	UG-SERVICE
41119459	GRET	SVC	1/5/2023	1978	RET ABN	UG-SERVICE
40889164	GRET	SVC	11/14/2022	1978	RET ABN	UG-SERVICE
43542641	GRET	SVC	10/1/2024	1978	RET ABN	UG-SERVICE
42644685	GRET	SVC	1/31/2024	1978	RET ABN	UG-SERVICE
43700500	GRET	SVC	11/1/2024	1978	RET ABN	UG-SERVICE
43951709	GRET	SVC	12/26/2024	1978	RET ABN	UG-SERVICE
39705079	GRET	SVC	2/6/2024	1978	RET ABN	UG-SERVICE
42300614	GRET	SVC	10/30/2023	1978	RET ABN	UG-SERVICE
39234653	GRET	SVC	10/20/2021	1978	RET ABN	UG-SERVICE
41330352	GRET	SVC	3/3/2023	1978	RET ABN	UG-SERVICE
40499687	GRET	SVC	8/3/2022	1978	RET ABN	UG-SERVICE
39998868	GRET	SVC	4/13/2022	1978	RET ABN	UG-SERVICE
39022826	GRET	SVC	8/18/2021	1978	RET ABN	UG-SERVICE
36519628	GRET	SVC	6/27/2020	1978	RET ABN	UG-SERVICE
41424183	GRET	SVC	10/18/2023	1978	RET ABN	UG-SERVICE
40301430	GRET	SVC	6/13/2022	1978	RET ABN	UG-SERVICE
43370804	GRET	SVC	11/9/2024	1978	RET ABN	UG-SERVICE
41335186	GRET	SVC	3/8/2023	1978	RET ABN	UG-SERVICE
37953916	GRET	SVC	12/28/2020	1978	RET ABN	UG-SERVICE
41318361	GRET	SVC	3/3/2023	1978	RET ABN	UG-SERVICE
36040243	GRET	SVC	2/18/2020	1978	RET ABN	UG-SERVICE
41423881	GRET	SVC	10/18/2023	1978	RET ABN	UG-SERVICE
40009217	GRET	SVC	3/3/2022	1978	RET ABN	UG-SERVICE
38203369	GRET	SVC	3/9/2021	1978	RET ABN	UG-SERVICE
38504593	GRET	SVC	4/5/2021	1978	RET ABN	UG-SERVICE
39413160	GRET	SVC	11/13/2021	1978	RET ABN	UG-SERVICE
36988771	GRET	SVC	10/2/2020	1978	RET ABN	UG-SERVICE
43825011	GRET	SVC	11/18/2024	1978	RET ABN	UG-SERVICE
41411750	GRET	SVC	4/2/2024	1978	RET ABN	UG-SERVICE
41330357	GRET	SVC	3/5/2023	1978	RET ABN	UG-SERVICE
41471842	GRET	SVC	3/29/2023	1978	RET ABN	UG-SERVICE
43245141	GRET	SVC	9/11/2024	1978	RET ABN	UG-SERVICE
39475295	GRET	SVC	12/6/2021	1978	RET ABN	UG-SERVICE
40897251	GRET	SVC	10/29/2022	1978	RET ABN	UG-SERVICE
41954710	GRET	SVC	8/6/2023	1978	RET ABN	UG-SERVICE
36440772	GRET	SVC	7/20/2020	1978	RET ABN	UG-SERVICE
39391060	GRET	SVC	11/7/2021	1978	RET ABN	UG-SERVICE
40277150	GRET	SVC	4/27/2023	1978	RET ABN	UG-SERVICE
39336889	GRET	SVC	12/21/2021	1978	RET ABN	UG-SERVICE
43364929	GRET	SVC	10/18/2024	1978	RET ABN	UG-SERVICE
36878600	GRET	SVC	8/29/2020	1978	RET ABN	UG-SERVICE
40513379	GRET	SVC	8/2/2022	1978	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39741831	GRET	SVC	2/23/2022	1978	RET ABN	UG-SERVICE
41342922	GRET	SVC	3/7/2023	1978	RET ABN	UG-SERVICE
43947177	GRET	SVC	12/23/2024	1978	RET ABN	UG-SERVICE
40793579	GRET	SVC	10/10/2022	1978	RET ABN	UG-SERVICE
40492819	GRET	SVC	7/25/2022	1978	RET ABN	UG-SERVICE
43371414	GRET	SVC	7/31/2024	1978	RET ABN	UG-SERVICE
43774808	GRET	SVC	11/1/2024	1978	RET ABN	UG-SERVICE
39721125	GRET	SVC	1/24/2022	1978	RET ABN	UG-SERVICE
41182811	GRET	SVC	1/18/2023	1978	RET ABN	UG-SERVICE
43923876	GRET	SVC	12/9/2024	1978	RET ABN	UG-SERVICE
41408200	GRET	SVC	4/2/2024	1978	RET ABN	UG-SERVICE
39894611	GRET	SVC	3/15/2022	1978	RET ABN	UG-SERVICE
43244991	GRET	SVC	9/19/2024	1978	RET ABN	UG-SERVICE
36074093	GRET	SVC	3/2/2020	1978	RET ABN	UG-SERVICE
41622981	GRET	SVC	5/12/2023	1978	RET ABN	UG-SERVICE
39552038	GRET	SVC	12/16/2021	1978	RET ABN	UG-SERVICE
38441388	GRET	SVC	1/6/2022	1978	RET ABN	UG-SERVICE
43245062	GRET	SVC	9/19/2024	1978	RET ABN	UG-SERVICE
41049774	GRET	SVC	2/20/2023	1978	RET ABN	UG-SERVICE
38252172	GRET	SVC	3/18/2021	1978	RET ABN	UG-SERVICE
42480931	GRET	SVC	12/14/2023	1978	RET ABN	UG-SERVICE
41222788	GRET	SVC	1/31/2023	1978	RET ABN	UG-SERVICE
36203639	GRET	SVC	4/23/2020	1978	RET ABN	UG-SERVICE
43680139	GRET	SVC	12/11/2024	1978	RET ABN	UG-SERVICE
43860695	GRET	SVC	11/21/2024	1978	RET ABN	UG-SERVICE
39413281	GRET	SVC	11/10/2021	1978	RET ABN	UG-SERVICE
41569451	GRET	SVC	4/25/2023	1978	RET ABN	UG-SERVICE
41099611	GRET	SVC	1/12/2023	1978	RET ABN	UG-SERVICE
35843287	GRET	SVC	1/2/2020	1978	RET ABN	UG-SERVICE
39757423	GRET	SVC	2/1/2022	1978	RET ABN	UG-SERVICE
43680103	GRET	SVC	10/29/2024	1978	RET ABN	UG-SERVICE
40744233	GRET	SVC	9/24/2022	1978	RET ABN	UG-SERVICE
43468973	GRET	SVC	8/22/2024	1978	RET ABN	UG-SERVICE
37982150	GRET	SVC	12/28/2020	1978	RET ABN	UG-SERVICE
41916724	GRET	SVC	7/26/2023	1978	RET ABN	UG-SERVICE
36180723	GRET	SVC	5/4/2020	1978	RET ABN	UG-SERVICE
41080842	GRET	SVC	12/19/2022	1978	RET ABN	UG-SERVICE
43680027	GRET	SVC	10/29/2024	1978	RET ABN	UG-SERVICE
35888172	GRET	SVC	1/14/2020	1978	RET ABN	UG-SERVICE
40707534	GRET	SVC	10/10/2022	1978	RET ABN	UG-SERVICE
36087638	GRET	SVC	3/4/2020	1978	RET ABN	UG-SERVICE
36122136	GRET	SVC	11/5/2020	1978	RET ABN	UG-SERVICE
39570477	GRET	SVC	12/13/2021	1978	RET ABN	UG-SERVICE
43245144	GRET	SVC	9/11/2024	1978	RET ABN	UG-SERVICE
42295854	GRET	SVC	10/31/2023	1978	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36038974	GRET	SVC	2/18/2020	1978	RET ABN	UG-SERVICE
39705128	GRET	SVC	2/6/2024	1978	RET ABN	UG-SERVICE
41182814	GRET	SVC	1/18/2023	1978	RET ABN	UG-SERVICE
40046866	GRET	SVC	12/17/2021	1978	RET ABN	UG-SERVICE
41913837	GRET	SVC	7/21/2023	1978	RET ABN	UG-SERVICE
42745903	GRET	SVC	2/20/2024	1978	RET ABN	UG-SERVICE
41423793	GRET	SVC	9/12/2023	1978	RET ABN	UG-SERVICE
38113503	GRET	SVC	2/9/2021	1978	RET ABN	UG-SERVICE
40111760	GRET	SVC	4/27/2022	1978	RET ABN	UG-SERVICE
39666667	GRET	SVC	11/18/2022	1978	RET ABN	UG-SERVICE
38362961	GRET	SVC	4/13/2021	1978	RET ABN	UG-SERVICE
38565188	GRET	SVC	6/1/2021	1978	RET ABN	UG-SERVICE
37070642	GRET	SVC	10/12/2020	1978	RET ABN	UG-SERVICE
43573408	GRET	SVC	9/17/2024	1978	RET ABN	UG-SERVICE
43250335	GRET	SVC	12/11/2024	1978	RET ABN	UG-SERVICE
42487756	GRET	SVC	7/18/2024	1978	RET ABN	UG-SERVICE
32667132	GRET	SVC	9/30/2020	1978	RET ABN	UG-SERVICE
43245142	GRET	SVC	9/11/2024	1978	RET ABN	UG-SERVICE
39717292	GRET	SVC	1/25/2022	1978	RET ABN	UG-SERVICE
36119409	GRET	SVC	11/5/2020	1978	RET ABN	UG-SERVICE
43407213	GRET	SVC	10/21/2024	1978	RET ABN	UG-SERVICE
40352826	GRET	SVC	7/1/2022	1978	RET ABN	UG-SERVICE
41140321	GRET	SVC	1/5/2023	1978	RET ABN	UG-SERVICE
36425707	GRET	SVC	6/26/2020	1978	RET ABN	UG-SERVICE
39727358	GRET	SVC	2/16/2022	1978	RET ABN	UG-SERVICE
40488448	GRET	SVC	7/26/2022	1978	RET ABN	UG-SERVICE
38446270	GRET	SVC	5/7/2021	1978	RET ABN	UG-SERVICE
36017684	GRET	SVC	3/11/2020	1978	RET ABN	UG-SERVICE
39067277	GRET	SVC	2/12/2022	1978	RET ABN	UG-SERVICE
41347207	GRET	SVC	3/11/2023	1978	RET ABN	UG-SERVICE
41969349	GRET	SVC	7/30/2024	1978	RET ABN	UG-SERVICE
36916408	GRET	SVC	9/10/2020	1978	RET ABN	UG-SERVICE
36173900	GRET	SVC	6/16/2020	1978	RET ABN	UG-SERVICE
43339919	GRET	SVC	7/23/2024	1978	RET ABN	UG-SERVICE
40840408	GRET	SVC	10/26/2022	1978	RET ABN	UG-SERVICE
39413164	GRET	SVC	11/13/2021	1978	RET ABN	UG-SERVICE
36698675	GRET	SVC	7/21/2020	1979	RET ABN	UG-SERVICE
42413837	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
39466825	GRET	SVC	11/27/2021	1979	RET ABN	UG-SERVICE
39520886	GRET	SVC	12/14/2021	1979	RET ABN	UG-SERVICE
42376801	GRET	SVC	11/16/2023	1979	RET ABN	UG-SERVICE
41429216	GRET	SVC	3/22/2023	1979	RET ABN	UG-SERVICE
38070432	GRET	SVC	2/1/2021	1979	RET ABN	UG-SERVICE
40644173	GRET	SVC	9/9/2022	1979	RET ABN	UG-SERVICE
39409453	GRET	SVC	12/2/2021	1979	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41284215	GRET	SVC	2/17/2023	1979	RET ABN	UG-SERVICE
42138662	GRET	SVC	9/22/2023	1979	RET ABN	UG-SERVICE
36207568	GRET	SVC	4/24/2020	1979	RET ABN	UG-SERVICE
36959592	GRET	SVC	9/16/2020	1979	RET ABN	UG-SERVICE
41341619	GRET	SVC	3/21/2023	1979	RET ABN	UG-SERVICE
40448086	GRET	SVC	7/12/2022	1979	RET ABN	UG-SERVICE
39567730	GRET	SVC	12/20/2021	1979	RET ABN	UG-SERVICE
39860344	GRET	SVC	3/5/2022	1979	RET ABN	UG-SERVICE
39077881	GRET	SVC	1/31/2022	1979	RET ABN	UG-SERVICE
41604795	GRET	SVC	5/8/2023	1979	RET ABN	UG-SERVICE
43063052	GRET	SVC	5/16/2024	1979	RET ABN	UG-SERVICE
40448799	GRET	SVC	7/18/2022	1979	RET ABN	UG-SERVICE
39555445	GRET	SVC	12/20/2021	1979	RET ABN	UG-SERVICE
43967973	GRET	SVC	12/23/2024	1979	RET ABN	UG-SERVICE
40793521	GRET	SVC	10/11/2022	1979	RET ABN	UG-SERVICE
41408290	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
40719004	GRET	SVC	9/19/2022	1979	RET ABN	UG-SERVICE
41531000	GRET	SVC	4/22/2023	1979	RET ABN	UG-SERVICE
40371191	GRET	SVC	7/6/2022	1979	RET ABN	UG-SERVICE
43318359	GRET	SVC	8/6/2024	1979	RET ABN	UG-SERVICE
41530832	GRET	SVC	4/22/2023	1979	RET ABN	UG-SERVICE
43632714	GRET	SVC	9/27/2024	1979	RET ABN	UG-SERVICE
42192216	GRET	SVC	10/6/2023	1979	RET ABN	UG-SERVICE
41513722	GRET	SVC	5/30/2023	1979	RET ABN	UG-SERVICE
41411408	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
41146781	GRET	SVC	1/11/2023	1979	RET ABN	UG-SERVICE
39619065	GRET	SVC	12/30/2021	1979	RET ABN	UG-SERVICE
39768731	GRET	SVC	2/9/2022	1979	RET ABN	UG-SERVICE
41429924	GRET	SVC	9/13/2023	1979	RET ABN	UG-SERVICE
43703190	GRET	SVC	10/17/2024	1979	RET ABN	UG-SERVICE
40805615	GRET	SVC	10/11/2022	1979	RET ABN	UG-SERVICE
43371587	GRET	SVC	7/31/2024	1979	RET ABN	UG-SERVICE
37918344	GRET	SVC	12/13/2020	1979	RET ABN	UG-SERVICE
38603605	GRET	SVC	6/7/2021	1979	RET ABN	UG-SERVICE
36916073	GRET	SVC	9/10/2020	1979	RET ABN	UG-SERVICE
38044488	GRET	SVC	1/22/2021	1979	RET ABN	UG-SERVICE
43792013	GRET	SVC	11/12/2024	1979	RET ABN	UG-SERVICE
40943515	GRET	SVC	11/15/2022	1979	RET ABN	UG-SERVICE
43481040	GRET	SVC	11/2/2024	1979	RET ABN	UG-SERVICE
39731727	GRET	SVC	1/26/2022	1979	RET ABN	UG-SERVICE
37286082	GRET	SVC	12/13/2020	1979	RET ABN	UG-SERVICE
39273719	GRET	SVC	10/12/2021	1979	RET ABN	UG-SERVICE
41906506	GRET	SVC	7/26/2023	1979	RET ABN	UG-SERVICE
43477773	GRET	SVC	8/26/2024	1979	RET ABN	UG-SERVICE
42212040	GRET	SVC	10/11/2023	1979	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36042960	GRET	SVC	2/19/2020	1979	RET ABN	UG-SERVICE
41075200	GRET	SVC	12/21/2022	1979	RET ABN	UG-SERVICE
38671336	GRET	SVC	6/25/2021	1979	RET ABN	UG-SERVICE
39731099	GRET	SVC	1/27/2022	1979	RET ABN	UG-SERVICE
41808286	GRET	SVC	6/27/2023	1979	RET ABN	UG-SERVICE
42330195	GRET	SVC	11/4/2023	1979	RET ABN	UG-SERVICE
39389319	GRET	SVC	12/10/2021	1979	RET ABN	UG-SERVICE
43014476	GRET	SVC	5/3/2024	1979	RET ABN	UG-SERVICE
41212060	GRET	SVC	1/19/2023	1979	RET ABN	UG-SERVICE
41706450	GRET	SVC	6/5/2023	1979	RET ABN	UG-SERVICE
41227101	GRET	SVC	1/31/2023	1979	RET ABN	UG-SERVICE
43408598	GRET	SVC	8/10/2024	1979	RET ABN	UG-SERVICE
42405114	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
40855584	GRET	SVC	10/24/2022	1979	RET ABN	UG-SERVICE
38370542	GRET	SVC	4/14/2021	1979	RET ABN	UG-SERVICE
43632137	GRET	SVC	9/27/2024	1979	RET ABN	UG-SERVICE
36134998	GRET	SVC	3/19/2020	1979	RET ABN	UG-SERVICE
41429927	GRET	SVC	9/13/2023	1979	RET ABN	UG-SERVICE
40737732	GRET	SVC	9/26/2022	1979	RET ABN	UG-SERVICE
41701506	GRET	SVC	5/31/2023	1979	RET ABN	UG-SERVICE
41411403	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
42519603	GRET	SVC	12/28/2023	1979	RET ABN	UG-SERVICE
40192726	GRET	SVC	5/25/2022	1979	RET ABN	UG-SERVICE
43365689	GRET	SVC	12/18/2024	1979	RET ABN	UG-SERVICE
41443234	GRET	SVC	3/27/2023	1979	RET ABN	UG-SERVICE
36255845	GRET	SVC	4/24/2020	1979	RET ABN	UG-SERVICE
42587539	GRET	SVC	1/30/2024	1979	RET ABN	UG-SERVICE
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36918267	GRET	SVC	9/3/2020	1979	RET ABN	UG-SERVICE
39735998	GRET	SVC	1/26/2022	1979	RET ABN	UG-SERVICE
39034555	GRET	SVC	9/13/2021	1979	RET ABN	UG-SERVICE
41278228	GRET	SVC	2/13/2023	1979	RET ABN	UG-SERVICE
43966498	GRET	SVC	12/23/2024	1979	RET ABN	UG-SERVICE
41424712	GRET	SVC	10/18/2023	1979	RET ABN	UG-SERVICE
38513285	GRET	SVC	5/17/2021	1979	RET ABN	UG-SERVICE
38741032	GRET	SVC	7/28/2021	1979	RET ABN	UG-SERVICE
39495068	GRET	SVC	12/6/2021	1979	RET ABN	UG-SERVICE
40353038	GRET	SVC	6/25/2022	1979	RET ABN	UG-SERVICE
42404220	GRET	SVC	11/18/2023	1979	RET ABN	UG-SERVICE
41321707	GRET	SVC	3/2/2023	1979	RET ABN	UG-SERVICE
40778899	GRET	SVC	10/5/2022	1979	RET ABN	UG-SERVICE
42556259	GRET	SVC	1/4/2024	1979	RET ABN	UG-SERVICE
42550578	GRET	SVC	1/6/2024	1979	RET ABN	UG-SERVICE
41015459	GRET	SVC	12/3/2022	1979	RET ABN	UG-SERVICE
39495073	GRET	SVC	12/6/2021	1979	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39731383	GRET	SVC	1/26/2022	1979	RET ABN	UG-SERVICE
43569826	GRET	SVC	9/16/2024	1979	RET ABN	UG-SERVICE
41969560	GRET	SVC	8/1/2024	1979	RET ABN	UG-SERVICE
42021625	GRET	SVC	8/19/2023	1979	RET ABN	UG-SERVICE
41102804	GRET	SVC	1/12/2023	1979	RET ABN	UG-SERVICE
43605573	GRET	SVC	9/26/2024	1979	RET ABN	UG-SERVICE
38304985	GRET	SVC	4/5/2021	1979	RET ABN	UG-SERVICE
36959590	GRET	SVC	9/16/2020	1979	RET ABN	UG-SERVICE
40486333	GRET	SVC	7/30/2022	1979	RET ABN	UG-SERVICE
39437797	GRET	SVC	11/17/2021	1979	RET ABN	UG-SERVICE
41411517	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
37776578	GRET	SVC	11/23/2020	1979	RET ABN	UG-SERVICE
42774031	GRET	SVC	2/21/2024	1979	RET ABN	UG-SERVICE
39236819	GRET	SVC	10/11/2021	1979	RET ABN	UG-SERVICE
41407353	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
37887887	GRET	SVC	12/11/2020	1979	RET ABN	UG-SERVICE
36373986	GRET	SVC	6/1/2020	1979	RET ABN	UG-SERVICE
41408298	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
41302289	GRET	SVC	2/27/2023	1979	RET ABN	UG-SERVICE
42503354	GRET	SVC	12/21/2023	1979	RET ABN	UG-SERVICE
36282087	GRET	SVC	4/29/2020	1979	RET ABN	UG-SERVICE
40022702	GRET	SVC	4/20/2022	1979	RET ABN	UG-SERVICE
40341585	GRET	SVC	7/14/2022	1979	RET ABN	UG-SERVICE
42165917	GRET	SVC	9/19/2023	1979	RET ABN	UG-SERVICE
41407285	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
43864215	GRET	SVC	11/8/2024	1979	RET ABN	UG-SERVICE
39903448	GRET	SVC	3/25/2022	1979	RET ABN	UG-SERVICE
41429930	GRET	SVC	9/13/2023	1979	RET ABN	UG-SERVICE
39077658	GRET	SVC	1/31/2022	1979	RET ABN	UG-SERVICE
39674940	GRET	SVC	1/11/2022	1979	RET ABN	UG-SERVICE
38315073	GRET	SVC	2/26/2021	1979	RET ABN	UG-SERVICE
40813755	GRET	SVC	10/19/2022	1979	RET ABN	UG-SERVICE
38437018	GRET	SVC	5/5/2021	1979	RET ABN	UG-SERVICE
41411563	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
36177526	GRET	SVC	2/14/2020	1979	RET ABN	UG-SERVICE
41321748	GRET	SVC	2/28/2023	1979	RET ABN	UG-SERVICE
40537448	GRET	SVC	8/5/2022	1979	RET ABN	UG-SERVICE
36976514	GRET	SVC	9/25/2020	1979	RET ABN	UG-SERVICE
42185413	GRET	SVC	10/25/2023	1979	RET ABN	UG-SERVICE
37564157	GRET	SVC	11/23/2020	1979	RET ABN	UG-SERVICE
42745648	GRET	SVC	2/20/2024	1979	RET ABN	UG-SERVICE
41531391	GRET	SVC	4/17/2023	1979	RET ABN	UG-SERVICE
41424717	GRET	SVC	10/18/2023	1979	RET ABN	UG-SERVICE
36366991	GRET	SVC	5/28/2020	1979	RET ABN	UG-SERVICE
41083738	GRET	SVC	1/10/2023	1979	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43439271	GRET	SVC	8/13/2024	1979	RET ABN	UG-SERVICE
38491638	GRET	SVC	5/12/2021	1979	RET ABN	UG-SERVICE
41408203	GRET	SVC	10/19/2023	1979	RET ABN	UG-SERVICE
40144600	GRET	SVC	5/12/2022	1979	RET ABN	UG-SERVICE
38728537	GRET	SVC	7/6/2021	1979	RET ABN	UG-SERVICE
40802737	GRET	SVC	10/13/2022	1979	RET ABN	UG-SERVICE
41529726	GRET	SVC	4/17/2023	1979	RET ABN	UG-SERVICE
41621213	GRET	SVC	5/10/2023	1979	RET ABN	UG-SERVICE
43610664	GRET	SVC	12/12/2024	1979	RET ABN	UG-SERVICE
38671333	GRET	SVC	6/25/2021	1979	RET ABN	UG-SERVICE
38251709	GRET	SVC	3/22/2021	1979	RET ABN	UG-SERVICE
37894668	GRET	SVC	12/9/2020	1979	RET ABN	UG-SERVICE
35379334	GRET	SVC	3/6/2020	1979	RET ABN	UG-SERVICE
38849352	GRET	SVC	8/17/2021	1979	RET ABN	UG-SERVICE
42079301	GRET	SVC	9/6/2023	1979	RET ABN	UG-SERVICE
43506881	GRET	SVC	10/8/2024	1979	RET ABN	UG-SERVICE
40481577	GRET	SVC	7/28/2022	1979	RET ABN	UG-SERVICE
40578133	GRET	SVC	8/17/2022	1979	RET ABN	UG-SERVICE
43245022	GRET	SVC	9/11/2024	1979	RET ABN	UG-SERVICE
43224670	GRET	SVC	6/18/2024	1979	RET ABN	UG-SERVICE
38604517	GRET	SVC	6/13/2021	1979	RET ABN	UG-SERVICE
41273677	GRET	SVC	2/13/2023	1979	RET ABN	UG-SERVICE
36750102	GRET	SVC	9/21/2020	1979	RET ABN	UG-SERVICE
39731089	GRET	SVC	1/26/2022	1979	RET ABN	UG-SERVICE
36581451	GRET	SVC	7/22/2020	1979	RET ABN	UG-SERVICE
39257959	GRET	SVC	10/12/2021	1979	RET ABN	UG-SERVICE
37022478	GRET	SVC	10/6/2020	1979	RET ABN	UG-SERVICE
37925673	GRET	SVC	12/16/2020	1979	RET ABN	UG-SERVICE
43565699	GRET	SVC	9/17/2024	1979	RET ABN	UG-SERVICE
39761607	GRET	SVC	2/25/2022	1979	RET ABN	UG-SERVICE
40963050	GRET	SVC	12/15/2022	1979	RET ABN	UG-SERVICE
42247047	GRET	SVC	10/16/2023	1979	RET ABN	UG-SERVICE
36265671	GRET	SVC	5/1/2020	1979	RET ABN	UG-SERVICE
30804651	GRET	SVC	1/13/2020	1979	RET ABN	UG-SERVICE
36874995	GRET	SVC	8/31/2020	1979	RET ABN	UG-SERVICE
39466091	GRET	SVC	11/29/2021	1979	RET ABN	UG-SERVICE
43885143	GRET	SVC	11/27/2024	1979	RET ABN	UG-SERVICE
40156829	GRET	SVC	5/11/2022	1979	RET ABN	UG-SERVICE
39241006	GRET	SVC	10/6/2021	1979	RET ABN	UG-SERVICE
35925193	GRET	SVC	5/5/2020	1979	RET ABN	UG-SERVICE
41445652	GRET	SVC	4/14/2023	1979	RET ABN	UG-SERVICE
42806750	GRET	SVC	3/11/2024	1979	RET ABN	UG-SERVICE
41411564	GRET	SVC	4/2/2024	1979	RET ABN	UG-SERVICE
36046011	GRET	SVC	3/17/2020	1979	RET ABN	UG-SERVICE
42320556	GRET	SVC	11/4/2023	1979	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42983088	GRET	SVC	4/19/2024	1979	RET ABN	UG-SERVICE
41429217	GRET	SVC	3/22/2023	1979	RET ABN	UG-SERVICE
42407612	GRET	SVC	11/20/2023	1979	RET ABN	UG-SERVICE
38737824	GRET	SVC	7/8/2021	1979	RET ABN	UG-SERVICE
39958596	GRET	SVC	4/20/2022	1979	RET ABN	UG-SERVICE
38947476	GRET	SVC	8/10/2021	1979	RET ABN	UG-SERVICE
40826587	GRET	SVC	10/18/2022	1979	RET ABN	UG-SERVICE
40147210	GRET	SVC	5/10/2022	1979	RET ABN	UG-SERVICE
40909894	GRET	SVC	11/8/2022	1979	RET ABN	UG-SERVICE
41067104	GRET	SVC	12/15/2022	1979	RET ABN	UG-SERVICE
39921796	GRET	SVC	3/23/2022	1979	RET ABN	UG-SERVICE
35866021	GRET	SVC	1/30/2020	1980	RET ABN	UG-SERVICE
38507917	GRET	SVC	5/19/2021	1980	RET ABN	UG-SERVICE
36867885	GRET	SVC	9/15/2020	1980	RET ABN	UG-SERVICE
42646850	GRET	SVC	2/1/2024	1980	RET ABN	UG-SERVICE
40806772	GRET	SVC	10/13/2022	1980	RET ABN	UG-SERVICE
37918342	GRET	SVC	12/14/2020	1980	RET ABN	UG-SERVICE
42498461	GRET	SVC	12/20/2023	1980	RET ABN	UG-SERVICE
42682551	GRET	SVC	2/12/2024	1980	RET ABN	UG-SERVICE
39609361	GRET	SVC	12/23/2021	1980	RET ABN	UG-SERVICE
43245011	GRET	SVC	9/19/2024	1980	RET ABN	UG-SERVICE
40837418	GRET	SVC	10/20/2022	1980	RET ABN	UG-SERVICE
43052299	GRET	SVC	5/13/2024	1980	RET ABN	UG-SERVICE
43477897	GRET	SVC	9/5/2024	1980	RET ABN	UG-SERVICE
35926332	GRET	SVC	1/22/2020	1980	RET ABN	UG-SERVICE
35938717	GRET	SVC	1/27/2020	1980	RET ABN	UG-SERVICE
37082344	GRET	SVC	10/16/2020	1980	RET ABN	UG-SERVICE
37887831	GRET	SVC	12/8/2020	1980	RET ABN	UG-SERVICE
38116253	GRET	SVC	2/9/2021	1980	RET ABN	UG-SERVICE
38170941	GRET	SVC	2/19/2021	1980	RET ABN	UG-SERVICE
36822003	GRET	SVC	8/20/2020	1980	RET ABN	UG-SERVICE
43985794	GRET	SVC	12/28/2024	1980	RET ABN	UG-SERVICE
40863154	GRET	SVC	10/22/2022	1980	RET ABN	UG-SERVICE
39194660	GRET	SVC	9/29/2021	1980	RET ABN	UG-SERVICE
38200822	GRET	SVC	3/11/2021	1980	RET ABN	UG-SERVICE
36926676	GRET	SVC	9/15/2020	1980	RET ABN	UG-SERVICE
36727692	GRET	SVC	7/30/2020	1980	RET ABN	UG-SERVICE
38808386	GRET	SVC	7/26/2021	1980	RET ABN	UG-SERVICE
40359797	GRET	SVC	12/12/2022	1980	RET ABN	UG-SERVICE
36047670	GRET	SVC	2/20/2020	1980	RET ABN	UG-SERVICE
39745882	GRET	SVC	1/31/2022	1980	RET ABN	UG-SERVICE
42217287	GRET	SVC	10/13/2023	1980	RET ABN	UG-SERVICE
36730903	GRET	SVC	8/14/2020	1980	RET ABN	UG-SERVICE
42405116	GRET	SVC	12/1/2023	1980	RET ABN	UG-SERVICE
41965367	GRET	SVC	8/12/2023	1980	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38880419	GRET	SVC	8/26/2021	1980	RET ABN	UG-SERVICE
35945211	GRET	SVC	1/27/2020	1980	RET ABN	UG-SERVICE
39534511	GRET	SVC	12/14/2021	1980	RET ABN	UG-SERVICE
38113255	GRET	SVC	2/8/2021	1980	RET ABN	UG-SERVICE
38284674	GRET	SVC	5/17/2021	1980	RET ABN	UG-SERVICE
43177005	GRET	SVC	6/17/2024	1980	RET ABN	UG-SERVICE
37087444	GRET	SVC	10/16/2020	1980	RET ABN	UG-SERVICE
38692011	GRET	SVC	7/16/2021	1980	RET ABN	UG-SERVICE
43324199	GRET	SVC	8/23/2024	1980	RET ABN	UG-SERVICE
38666432	GRET	SVC	6/24/2021	1980	RET ABN	UG-SERVICE
36006012	GRET	SVC	2/11/2020	1980	RET ABN	UG-SERVICE
43737110	GRET	SVC	10/22/2024	1980	RET ABN	UG-SERVICE
43345778	GRET	SVC	7/22/2024	1980	RET ABN	UG-SERVICE
43506825	GRET	SVC	10/3/2024	1980	RET ABN	UG-SERVICE
37834392	GRET	SVC	11/30/2020	1980	RET ABN	UG-SERVICE
40637086	GRET	SVC	8/30/2022	1980	RET ABN	UG-SERVICE
40788026	GRET	SVC	10/10/2022	1980	RET ABN	UG-SERVICE
41118205	GRET	SVC	1/3/2023	1980	RET ABN	UG-SERVICE
36404827	GRET	SVC	6/10/2020	1980	RET ABN	UG-SERVICE
41431153	GRET	SVC	3/28/2023	1980	RET ABN	UG-SERVICE
39977279	GRET	SVC	4/7/2022	1980	RET ABN	UG-SERVICE
40701293	GRET	SVC	9/13/2022	1980	RET ABN	UG-SERVICE
38135257	GRET	SVC	2/9/2021	1980	RET ABN	UG-SERVICE
39408469	GRET	SVC	11/6/2021	1980	RET ABN	UG-SERVICE
40400195	GRET	SVC	8/10/2022	1980	RET ABN	UG-SERVICE
40616873	GRET	SVC	8/25/2022	1980	RET ABN	UG-SERVICE
40829046	GRET	SVC	10/22/2022	1980	RET ABN	UG-SERVICE
36297314	GRET	SVC	5/13/2020	1980	RET ABN	UG-SERVICE
40737880	GRET	SVC	10/1/2022	1980	RET ABN	UG-SERVICE
39940127	GRET	SVC	6/27/2022	1980	RET ABN	UG-SERVICE
38414865	GRET	SVC	4/27/2021	1980	RET ABN	UG-SERVICE
36876670	GRET	SVC	9/10/2020	1980	RET ABN	UG-SERVICE
43974740	GRET	SVC	12/26/2024	1980	RET ABN	UG-SERVICE
40619135	GRET	SVC	8/11/2022	1980	RET ABN	UG-SERVICE
41277505	GRET	SVC	2/13/2023	1980	RET ABN	UG-SERVICE
36039967	GRET	SVC	2/13/2020	1980	RET ABN	UG-SERVICE
40275027	GRET	SVC	7/5/2022	1980	RET ABN	UG-SERVICE
38251173	GRET	SVC	3/16/2021	1980	RET ABN	UG-SERVICE
41083441	GRET	SVC	12/20/2022	1980	RET ABN	UG-SERVICE
36709895	GRET	SVC	8/3/2020	1980	RET ABN	UG-SERVICE
41318142	GRET	SVC	3/3/2023	1980	RET ABN	UG-SERVICE
38113254	GRET	SVC	2/8/2021	1980	RET ABN	UG-SERVICE
39730649	GRET	SVC	1/28/2022	1980	RET ABN	UG-SERVICE
39808430	GRET	SVC	2/16/2022	1980	RET ABN	UG-SERVICE
36198374	GRET	SVC	5/1/2020	1980	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43767434	GRET	SVC	11/12/2024	1980	RET ABN	UG-SERVICE
43125485	GRET	SVC	6/7/2024	1980	RET ABN	UG-SERVICE
43678617	GRET	SVC	11/1/2024	1980	RET ABN	UG-SERVICE
38167316	GRET	SVC	2/19/2021	1980	RET ABN	UG-SERVICE
43703191	GRET	SVC	10/18/2024	1980	RET ABN	UG-SERVICE
38167318	GRET	SVC	2/19/2021	1980	RET ABN	UG-SERVICE
36297313	GRET	SVC	5/13/2020	1980	RET ABN	UG-SERVICE
38342400	GRET	SVC	4/12/2021	1980	RET ABN	UG-SERVICE
36590784	GRET	SVC	7/12/2020	1980	RET ABN	UG-SERVICE
37560682	GRET	SVC	11/13/2020	1980	RET ABN	UG-SERVICE
40518272	GRET	SVC	8/3/2022	1980	RET ABN	UG-SERVICE
38260202	GRET	SVC	4/9/2021	1980	RET ABN	UG-SERVICE
39977276	GRET	SVC	4/7/2022	1980	RET ABN	UG-SERVICE
36805445	GRET	SVC	8/20/2020	1980	RET ABN	UG-SERVICE
43793034	GRET	SVC	11/4/2024	1980	RET ABN	UG-SERVICE
41043685	GRET	SVC	12/12/2022	1980	RET ABN	UG-SERVICE
40400196	GRET	SVC	8/10/2022	1980	RET ABN	UG-SERVICE
40513288	GRET	SVC	8/4/2022	1980	RET ABN	UG-SERVICE
42435570	GRET	SVC	12/15/2023	1980	RET ABN	UG-SERVICE
38170519	GRET	SVC	2/19/2021	1980	RET ABN	UG-SERVICE
41411765	GRET	SVC	4/2/2024	1980	RET ABN	UG-SERVICE
35960002	GRET	SVC	1/27/2020	1980	RET ABN	UG-SERVICE
43623490	GRET	SVC	12/5/2024	1980	RET ABN	UG-SERVICE
40618740	GRET	SVC	9/2/2022	1980	RET ABN	UG-SERVICE
41407774	GRET	SVC	4/2/2024	1980	RET ABN	UG-SERVICE
38766858	GRET	SVC	7/12/2021	1980	RET ABN	UG-SERVICE
42217502	GRET	SVC	10/13/2023	1980	RET ABN	UG-SERVICE
38159499	GRET	SVC	2/18/2021	1980	RET ABN	UG-SERVICE
42767217	GRET	SVC	9/19/2024	1980	RET ABN	UG-SERVICE
39663182	GRET	SVC	12/29/2021	1980	RET ABN	UG-SERVICE
42696012	GRET	SVC	2/14/2024	1980	RET ABN	UG-SERVICE
42083849	GRET	SVC	9/10/2023	1980	RET ABN	UG-SERVICE
42678185	GRET	SVC	2/7/2024	1980	RET ABN	UG-SERVICE
39341151	GRET	SVC	10/26/2021	1980	RET ABN	UG-SERVICE
36715000	GRET	SVC	8/4/2020	1980	RET ABN	UG-SERVICE
41117034	GRET	SVC	1/12/2023	1980	RET ABN	UG-SERVICE
43324508	GRET	SVC	10/15/2024	1980	RET ABN	UG-SERVICE
43144648	GRET	SVC	6/7/2024	1980	RET ABN	UG-SERVICE
43318347	GRET	SVC	8/13/2024	1980	RET ABN	UG-SERVICE
41063071	GRET	SVC	12/11/2022	1980	RET ABN	UG-SERVICE
42784886	GRET	SVC	3/4/2024	1980	RET ABN	UG-SERVICE
39989337	GRET	SVC	4/25/2022	1980	RET ABN	UG-SERVICE
39097214	GRET	SVC	9/10/2021	1980	RET ABN	UG-SERVICE
42165918	GRET	SVC	9/19/2023	1980	RET ABN	UG-SERVICE
42190592	GRET	SVC	10/4/2023	1980	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42838256	GRET	SVC	3/15/2024	1980	RET ABN	UG-SERVICE
38159497	GRET	SVC	2/16/2021	1980	RET ABN	UG-SERVICE
36690178	GRET	SVC	7/29/2020	1980	RET ABN	UG-SERVICE
42973050	GRET	SVC	4/22/2024	1980	RET ABN	UG-SERVICE
42904312	GRET	SVC	4/11/2024	1980	RET ABN	UG-SERVICE
37423846	GRET	SVC	11/10/2020	1980	RET ABN	UG-SERVICE
36139991	GRET	SVC	3/16/2020	1980	RET ABN	UG-SERVICE
38113253	GRET	SVC	2/8/2021	1980	RET ABN	UG-SERVICE
39876288	GRET	SVC	3/14/2022	1980	RET ABN	UG-SERVICE
39895862	GRET	SVC	4/22/2022	1980	RET ABN	UG-SERVICE
43471134	GRET	SVC	8/20/2024	1980	RET ABN	UG-SERVICE
36066959	GRET	SVC	2/27/2020	1980	RET ABN	UG-SERVICE
36657935	GRET	SVC	6/11/2020	1980	RET ABN	UG-SERVICE
42217358	GRET	SVC	10/13/2023	1980	RET ABN	UG-SERVICE
36704634	GRET	SVC	7/29/2020	1980	RET ABN	UG-SERVICE
41187919	GRET	SVC	1/17/2023	1980	RET ABN	UG-SERVICE
40396051	GRET	SVC	7/6/2022	1980	RET ABN	UG-SERVICE
42865500	GRET	SVC	2/15/2024	1980	RET ABN	UG-SERVICE
37004084	GRET	SVC	10/16/2020	1980	RET ABN	UG-SERVICE
40900946	GRET	SVC	12/3/2022	1980	RET ABN	UG-SERVICE
38534653	GRET	SVC	5/25/2021	1980	RET ABN	UG-SERVICE
43440669	GRET	SVC	8/14/2024	1980	RET ABN	UG-SERVICE
36953644	GRET	SVC	9/20/2020	1980	RET ABN	UG-SERVICE
40036782	GRET	SVC	4/24/2022	1980	RET ABN	UG-SERVICE
40962785	GRET	SVC	11/22/2022	1980	RET ABN	UG-SERVICE
43610731	GRET	SVC	10/20/2024	1980	RET ABN	UG-SERVICE
40372553	GRET	SVC	7/5/2022	1980	RET ABN	UG-SERVICE
39378017	GRET	SVC	11/2/2021	1980	RET ABN	UG-SERVICE
43506592	GRET	SVC	9/18/2024	1980	RET ABN	UG-SERVICE
43167495	GRET	SVC	7/5/2024	1980	RET ABN	UG-SERVICE
35960719	GRET	SVC	1/31/2020	1980	RET ABN	UG-SERVICE
38116247	GRET	SVC	2/9/2021	1980	RET ABN	UG-SERVICE
37089338	GRET	SVC	10/20/2020	1980	RET ABN	UG-SERVICE
43244748	GRET	SVC	9/13/2024	1980	RET ABN	UG-SERVICE
42522515	GRET	SVC	12/27/2023	1980	RET ABN	UG-SERVICE
38217494	GRET	SVC	3/22/2021	1980	RET ABN	UG-SERVICE
41774863	GRET	SVC	6/22/2023	1980	RET ABN	UG-SERVICE
39701495	GRET	SVC	1/18/2022	1980	RET ABN	UG-SERVICE
38786025	GRET	SVC	8/2/2021	1980	RET ABN	UG-SERVICE
38401291	GRET	SVC	4/20/2021	1980	RET ABN	UG-SERVICE
38353000	GRET	SVC	2/14/2023	1980	RET ABN	UG-SERVICE
41436522	GRET	SVC	3/27/2023	1980	RET ABN	UG-SERVICE
36260361	GRET	SVC	5/7/2020	1980	RET ABN	UG-SERVICE
40865777	GRET	SVC	10/27/2022	1980	RET ABN	UG-SERVICE
38167319	GRET	SVC	2/19/2021	1980	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42217394	GRET	SVC	10/13/2023	1980	RET ABN	UG-SERVICE
43379746	GRET	SVC	7/27/2024	1980	RET ABN	UG-SERVICE
42413380	GRET	SVC	11/27/2023	1980	RET ABN	UG-SERVICE
36759048	GRET	SVC	8/10/2020	1980	RET ABN	UG-SERVICE
43566832	GRET	SVC	10/3/2024	1980	RET ABN	UG-SERVICE
43673036	GRET	SVC	10/9/2024	1980	RET ABN	UG-SERVICE
41277506	GRET	SVC	2/24/2023	1980	RET ABN	UG-SERVICE
40497353	GRET	SVC	8/3/2022	1980	RET ABN	UG-SERVICE
38747941	GRET	SVC	7/16/2021	1980	RET ABN	UG-SERVICE
41585947	GRET	SVC	5/3/2023	1980	RET ABN	UG-SERVICE
40099808	GRET	SVC	5/2/2022	1980	RET ABN	UG-SERVICE
42194936	GRET	SVC	10/9/2023	1980	RET ABN	UG-SERVICE
39452999	GRET	SVC	11/22/2021	1980	RET ABN	UG-SERVICE
38116252	GRET	SVC	2/9/2021	1980	RET ABN	UG-SERVICE
39817525	GRET	SVC	2/23/2022	1980	RET ABN	UG-SERVICE
41509580	GRET	SVC	4/10/2023	1980	RET ABN	UG-SERVICE
38159496	GRET	SVC	2/16/2021	1980	RET ABN	UG-SERVICE
42083826	GRET	SVC	8/28/2023	1980	RET ABN	UG-SERVICE
42170550	GRET	SVC	10/3/2023	1980	RET ABN	UG-SERVICE
43506834	GRET	SVC	9/16/2024	1980	RET ABN	UG-SERVICE
35919327	GRET	SVC	1/16/2020	1980	RET ABN	UG-SERVICE
38662723	GRET	SVC	6/23/2021	1980	RET ABN	UG-SERVICE
39067596	GRET	SVC	9/23/2021	1980	RET ABN	UG-SERVICE
39855421	GRET	SVC	3/7/2022	1980	RET ABN	UG-SERVICE
35965176	GRET	SVC	1/26/2020	1980	RET ABN	UG-SERVICE
38331751	GRET	SVC	4/8/2021	1980	RET ABN	UG-SERVICE
39958831	GRET	SVC	4/26/2022	1980	RET ABN	UG-SERVICE
43245145	GRET	SVC	9/11/2024	1980	RET ABN	UG-SERVICE
42554523	GRET	SVC	1/9/2024	1980	RET ABN	UG-SERVICE
41051917	GRET	SVC	1/12/2023	1980	RET ABN	UG-SERVICE
42290696	GRET	SVC	9/16/2023	1980	RET ABN	UG-SERVICE
43540690	GRET	SVC	9/17/2024	1980	RET ABN	UG-SERVICE
39211525	GRET	SVC	9/27/2021	1980	RET ABN	UG-SERVICE
40905625	GRET	SVC	11/9/2022	1980	RET ABN	UG-SERVICE
37593381	GRET	SVC	11/16/2020	1980	RET ABN	UG-SERVICE
43551265	GRET	SVC	9/7/2024	1980	RET ABN	UG-SERVICE
40957854	GRET	SVC	11/21/2022	1980	RET ABN	UG-SERVICE
38135258	GRET	SVC	2/9/2021	1980	RET ABN	UG-SERVICE
43190559	GRET	SVC	6/14/2024	1980	RET ABN	UG-SERVICE
38520452	GRET	SVC	5/19/2021	1980	RET ABN	UG-SERVICE
42220667	GRET	SVC	10/16/2023	1980	RET ABN	UG-SERVICE
41186303	GRET	SVC	1/20/2023	1980	RET ABN	UG-SERVICE
40561831	GRET	SVC	8/17/2022	1980	RET ABN	UG-SERVICE
36734820	GRET	SVC	8/6/2020	1980	RET ABN	UG-SERVICE
39424078	GRET	SVC	4/29/2022	1980	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41284183	GRET	SVC	2/26/2023	1980	RET ABN	UG-SERVICE
38082913	GRET	SVC	2/1/2021	1980	RET ABN	UG-SERVICE
37288139	GRET	SVC	11/9/2020	1980	RET ABN	UG-SERVICE
41084274	GRET	SVC	12/21/2022	1980	RET ABN	UG-SERVICE
39917684	GRET	SVC	4/26/2022	1980	RET ABN	UG-SERVICE
42514792	GRET	SVC	12/29/2023	1980	RET ABN	UG-SERVICE
41411047	GRET	SVC	4/2/2024	1980	RET ABN	UG-SERVICE
38172263	GRET	SVC	2/25/2021	1980	RET ABN	UG-SERVICE
41296111	GRET	SVC	2/20/2023	1980	RET ABN	UG-SERVICE
35964247	GRET	SVC	1/31/2020	1980	RET ABN	UG-SERVICE
40515691	GRET	SVC	8/5/2022	1981	RET ABN	UG-SERVICE
40108945	GRET	SVC	5/6/2022	1981	RET ABN	UG-SERVICE
42957322	GRET	SVC	9/19/2024	1981	RET ABN	UG-SERVICE
36504620	GRET	SVC	7/21/2020	1981	RET ABN	UG-SERVICE
39158783	GRET	SVC	9/17/2021	1981	RET ABN	UG-SERVICE
41988878	GRET	SVC	8/14/2023	1981	RET ABN	UG-SERVICE
39114621	GRET	SVC	9/27/2021	1981	RET ABN	UG-SERVICE
36699118	GRET	SVC	7/28/2020	1981	RET ABN	UG-SERVICE
41529177	GRET	SVC	4/18/2023	1981	RET ABN	UG-SERVICE
42429557	GRET	SVC	11/28/2023	1981	RET ABN	UG-SERVICE
42427059	GRET	SVC	9/19/2024	1981	RET ABN	UG-SERVICE
42678163	GRET	SVC	2/7/2024	1981	RET ABN	UG-SERVICE
43612750	GRET	SVC	9/23/2024	1981	RET ABN	UG-SERVICE
42255111	GRET	SVC	4/2/2024	1981	RET ABN	UG-SERVICE
40777231	GRET	SVC	10/7/2022	1981	RET ABN	UG-SERVICE
40824097	GRET	SVC	10/18/2022	1981	RET ABN	UG-SERVICE
42205149	GRET	SVC	10/18/2023	1981	RET ABN	UG-SERVICE
37867772	GRET	SVC	12/6/2020	1981	RET ABN	UG-SERVICE
39372952	GRET	SVC	11/1/2021	1981	RET ABN	UG-SERVICE
40817911	GRET	SVC	11/3/2022	1981	RET ABN	UG-SERVICE
39829823	GRET	SVC	2/28/2022	1981	RET ABN	UG-SERVICE
39292398	GRET	SVC	11/8/2021	1981	RET ABN	UG-SERVICE
39821845	GRET	SVC	2/24/2022	1981	RET ABN	UG-SERVICE
42522226	GRET	SVC	12/28/2023	1981	RET ABN	UG-SERVICE
36448752	GRET	SVC	6/16/2020	1981	RET ABN	UG-SERVICE
41083935	GRET	SVC	12/21/2022	1981	RET ABN	UG-SERVICE
40824189	GRET	SVC	10/18/2022	1981	RET ABN	UG-SERVICE
43364936	GRET	SVC	10/15/2024	1981	RET ABN	UG-SERVICE
43587179	GRET	SVC	9/20/2024	1981	RET ABN	UG-SERVICE
40656092	GRET	SVC	9/16/2022	1981	RET ABN	UG-SERVICE
42175607	GRET	SVC	9/25/2023	1981	RET ABN	UG-SERVICE
42428954	GRET	SVC	4/2/2024	1981	RET ABN	UG-SERVICE
36207010	GRET	SVC	4/28/2020	1981	RET ABN	UG-SERVICE
39950829	GRET	SVC	5/14/2022	1981	RET ABN	UG-SERVICE
38037820	GRET	SVC	1/19/2021	1981	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43364935	GRET	SVC	10/15/2024	1981	RET ABN	UG-SERVICE
36469542	GRET	SVC	7/8/2020	1981	RET ABN	UG-SERVICE
41184328	GRET	SVC	1/18/2023	1981	RET ABN	UG-SERVICE
36177527	GRET	SVC	2/14/2020	1981	RET ABN	UG-SERVICE
40189511	GRET	SVC	5/24/2022	1981	RET ABN	UG-SERVICE
37639332	GRET	SVC	11/9/2020	1981	RET ABN	UG-SERVICE
40345195	GRET	SVC	6/27/2022	1981	RET ABN	UG-SERVICE
41288086	GRET	SVC	2/24/2023	1981	RET ABN	UG-SERVICE
38971803	GRET	SVC	8/30/2021	1981	RET ABN	UG-SERVICE
43765696	GRET	SVC	10/18/2024	1981	RET ABN	UG-SERVICE
41407667	GRET	SVC	4/2/2024	1981	RET ABN	UG-SERVICE
40751127	GRET	SVC	9/30/2022	1981	RET ABN	UG-SERVICE
36058338	GRET	SVC	2/25/2020	1981	RET ABN	UG-SERVICE
43364937	GRET	SVC	10/16/2024	1981	RET ABN	UG-SERVICE
41628115	GRET	SVC	5/16/2023	1981	RET ABN	UG-SERVICE
43456236	GRET	SVC	8/20/2024	1981	RET ABN	UG-SERVICE
36885931	GRET	SVC	9/2/2020	1981	RET ABN	UG-SERVICE
41164933	GRET	SVC	1/18/2023	1981	RET ABN	UG-SERVICE
42535827	GRET	SVC	12/28/2023	1981	RET ABN	UG-SERVICE
38616755	GRET	SVC	6/14/2021	1981	RET ABN	UG-SERVICE
41025632	GRET	SVC	4/4/2023	1981	RET ABN	UG-SERVICE
37113299	GRET	SVC	10/26/2020	1981	RET ABN	UG-SERVICE
41119447	GRET	SVC	1/5/2023	1981	RET ABN	UG-SERVICE
40825319	GRET	SVC	11/1/2022	1981	RET ABN	UG-SERVICE
42070210	GRET	SVC	9/1/2023	1981	RET ABN	UG-SERVICE
42216869	GRET	SVC	10/11/2023	1981	RET ABN	UG-SERVICE
41161391	GRET	SVC	1/18/2023	1981	RET ABN	UG-SERVICE
36977367	GRET	SVC	9/23/2020	1981	RET ABN	UG-SERVICE
42227312	GRET	SVC	10/31/2023	1981	RET ABN	UG-SERVICE
37004001	GRET	SVC	10/9/2020	1981	RET ABN	UG-SERVICE
43364938	GRET	SVC	10/19/2024	1981	RET ABN	UG-SERVICE
36712286	GRET	SVC	8/10/2020	1981	RET ABN	UG-SERVICE
40138088	GRET	SVC	5/9/2022	1981	RET ABN	UG-SERVICE
39439687	GRET	SVC	11/19/2021	1981	RET ABN	UG-SERVICE
36056285	GRET	SVC	2/24/2020	1981	RET ABN	UG-SERVICE
38324631	GRET	SVC	3/1/2021	1981	RET ABN	UG-SERVICE
38804665	GRET	SVC	8/2/2021	1981	RET ABN	UG-SERVICE
43801210	GRET	SVC	11/6/2024	1981	RET ABN	UG-SERVICE
37181835	GRET	SVC	10/29/2020	1981	RET ABN	UG-SERVICE
40821937	GRET	SVC	10/18/2022	1981	RET ABN	UG-SERVICE
42838191	GRET	SVC	3/20/2024	1981	RET ABN	UG-SERVICE
43318356	GRET	SVC	8/1/2024	1981	RET ABN	UG-SERVICE
36987348	GRET	SVC	9/23/2020	1981	RET ABN	UG-SERVICE
38484804	GRET	SVC	5/10/2021	1981	RET ABN	UG-SERVICE
37018536	GRET	SVC	10/1/2020	1981	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36207016	GRET	SVC	4/28/2020	1981	RET ABN	UG-SERVICE
36957850	GRET	SVC	9/9/2020	1981	RET ABN	UG-SERVICE
42248421	GRET	SVC	10/18/2023	1981	RET ABN	UG-SERVICE
43069749	GRET	SVC	5/20/2024	1981	RET ABN	UG-SERVICE
35969641	GRET	SVC	2/3/2020	1981	RET ABN	UG-SERVICE
39571349	GRET	SVC	11/22/2021	1981	RET ABN	UG-SERVICE
41388637	GRET	SVC	3/15/2023	1981	RET ABN	UG-SERVICE
39444730	GRET	SVC	12/2/2021	1981	RET ABN	UG-SERVICE
41516430	GRET	SVC	4/27/2023	1981	RET ABN	UG-SERVICE
40952957	GRET	SVC	11/17/2022	1981	RET ABN	UG-SERVICE
41411426	GRET	SVC	11/2/2023	1981	RET ABN	UG-SERVICE
40736068	GRET	SVC	9/27/2022	1981	RET ABN	UG-SERVICE
40865906	GRET	SVC	8/22/2023	1981	RET ABN	UG-SERVICE
43506821	GRET	SVC	10/11/2024	1981	RET ABN	UG-SERVICE
38289760	GRET	SVC	4/1/2021	1981	RET ABN	UG-SERVICE
38682325	GRET	SVC	7/1/2021	1981	RET ABN	UG-SERVICE
38606748	GRET	SVC	6/11/2021	1981	RET ABN	UG-SERVICE
43323973	GRET	SVC	10/14/2024	1981	RET ABN	UG-SERVICE
38741847	GRET	SVC	7/12/2021	1981	RET ABN	UG-SERVICE
42335278	GRET	SVC	4/2/2024	1981	RET ABN	UG-SERVICE
41185105	GRET	SVC	1/21/2023	1981	RET ABN	UG-SERVICE
40015541	GRET	SVC	4/16/2022	1981	RET ABN	UG-SERVICE
38266117	GRET	SVC	10/27/2021	1981	RET ABN	UG-SERVICE
43323972	GRET	SVC	7/22/2024	1981	RET ABN	UG-SERVICE
40386083	GRET	SVC	7/6/2022	1981	RET ABN	UG-SERVICE
36122706	GRET	SVC	11/5/2020	1981	RET ABN	UG-SERVICE
43564234	GRET	SVC	9/14/2024	1981	RET ABN	UG-SERVICE
41209954	GRET	SVC	1/31/2023	1981	RET ABN	UG-SERVICE
42965256	GRET	SVC	4/24/2024	1981	RET ABN	UG-SERVICE
39843596	GRET	SVC	3/2/2022	1981	RET ABN	UG-SERVICE
38407202	GRET	SVC	3/16/2021	1982	RET ABN	UG-SERVICE
40814058	GRET	SVC	10/19/2022	1982	RET ABN	UG-SERVICE
38505994	GRET	SVC	6/9/2021	1982	RET ABN	UG-SERVICE
40313520	GRET	SVC	6/15/2022	1982	RET ABN	UG-SERVICE
37564159	GRET	SVC	11/25/2020	1982	RET ABN	UG-SERVICE
36666826	GRET	SVC	7/20/2020	1982	RET ABN	UG-SERVICE
41968002	GRET	SVC	8/9/2023	1982	RET ABN	UG-SERVICE
36119404	GRET	SVC	11/5/2020	1982	RET ABN	UG-SERVICE
38091659	GRET	SVC	2/4/2021	1982	RET ABN	UG-SERVICE
39109977	GRET	SVC	9/8/2021	1982	RET ABN	UG-SERVICE
43896268	GRET	SVC	12/5/2024	1982	RET ABN	UG-SERVICE
42006525	GRET	SVC	8/16/2023	1982	RET ABN	UG-SERVICE
43329182	GRET	SVC	7/16/2024	1982	RET ABN	UG-SERVICE
39104840	GRET	SVC	7/30/2021	1982	RET ABN	UG-SERVICE
40831950	GRET	SVC	10/19/2022	1982	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
37848473	GRET	SVC	11/30/2020	1982	RET ABN	UG-SERVICE
38113506	GRET	SVC	2/10/2021	1982	RET ABN	UG-SERVICE
43428930	GRET	SVC	8/10/2024	1982	RET ABN	UG-SERVICE
40612445	GRET	SVC	10/27/2022	1982	RET ABN	UG-SERVICE
37848478	GRET	SVC	11/30/2020	1982	RET ABN	UG-SERVICE
43469158	GRET	SVC	8/24/2024	1982	RET ABN	UG-SERVICE
41436390	GRET	SVC	3/27/2023	1982	RET ABN	UG-SERVICE
40942685	GRET	SVC	11/28/2022	1982	RET ABN	UG-SERVICE
43324195	GRET	SVC	7/29/2024	1982	RET ABN	UG-SERVICE
37004013	GRET	SVC	9/29/2020	1982	RET ABN	UG-SERVICE
43353737	GRET	SVC	12/6/2024	1982	RET ABN	UG-SERVICE
38352970	GRET	SVC	2/17/2023	1982	RET ABN	UG-SERVICE
36916863	GRET	SVC	9/11/2020	1982	RET ABN	UG-SERVICE
41279149	GRET	SVC	2/13/2023	1982	RET ABN	UG-SERVICE
43883405	GRET	SVC	11/27/2024	1982	RET ABN	UG-SERVICE
43916042	GRET	SVC	12/7/2024	1982	RET ABN	UG-SERVICE
39243194	GRET	SVC	10/4/2021	1982	RET ABN	UG-SERVICE
40522355	GRET	SVC	8/13/2022	1982	RET ABN	UG-SERVICE
35865617	GRET	SVC	1/6/2020	1982	RET ABN	UG-SERVICE
41877455	GRET	SVC	8/28/2023	1982	RET ABN	UG-SERVICE
36255513	GRET	SVC	5/20/2020	1982	RET ABN	UG-SERVICE
43423327	GRET	SVC	9/11/2024	1982	RET ABN	UG-SERVICE
37739218	GRET	SVC	11/23/2020	1982	RET ABN	UG-SERVICE
41814868	GRET	SVC	6/27/2023	1982	RET ABN	UG-SERVICE
42332553	GRET	SVC	11/7/2023	1982	RET ABN	UG-SERVICE
38461565	GRET	SVC	5/5/2021	1982	RET ABN	UG-SERVICE
36121696	GRET	SVC	10/12/2020	1982	RET ABN	UG-SERVICE
39271873	GRET	SVC	10/26/2021	1982	RET ABN	UG-SERVICE
42408187	GRET	SVC	11/20/2023	1982	RET ABN	UG-SERVICE
42887631	GRET	SVC	4/4/2024	1982	RET ABN	UG-SERVICE
43934271	GRET	SVC	12/17/2024	1982	RET ABN	UG-SERVICE
40283208	GRET	SVC	6/9/2022	1982	RET ABN	UG-SERVICE
38844205	GRET	SVC	7/30/2021	1982	RET ABN	UG-SERVICE
41145263	GRET	SVC	1/9/2023	1982	RET ABN	UG-SERVICE
40860630	GRET	SVC	10/25/2022	1982	RET ABN	UG-SERVICE
42419098	GRET	SVC	12/14/2023	1982	RET ABN	UG-SERVICE
43496524	GRET	SVC	12/4/2024	1982	RET ABN	UG-SERVICE
38352971	GRET	SVC	2/17/2023	1982	RET ABN	UG-SERVICE
41463374	GRET	SVC	4/7/2023	1982	RET ABN	UG-SERVICE
39577719	GRET	SVC	12/27/2021	1982	RET ABN	UG-SERVICE
43205045	GRET	SVC	9/19/2024	1982	RET ABN	UG-SERVICE
36994454	GRET	SVC	9/28/2020	1982	RET ABN	UG-SERVICE
43312118	GRET	SVC	9/19/2024	1982	RET ABN	UG-SERVICE
42340279	GRET	SVC	11/7/2023	1982	RET ABN	UG-SERVICE
43272247	GRET	SVC	8/1/2024	1982	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41130361	GRET	SVC	6/10/2024	1982	RET ABN	UG-SERVICE
42327296	GRET	SVC	11/3/2023	1982	RET ABN	UG-SERVICE
43752302	GRET	SVC	11/23/2024	1982	RET ABN	UG-SERVICE
36566275	GRET	SVC	7/28/2020	1982	RET ABN	UG-SERVICE
35518622	GRET	SVC	3/8/2021	1983	RET ABN	UG-SERVICE
36348439	GRET	SVC	5/20/2020	1983	RET ABN	UG-SERVICE
37957717	GRET	SVC	12/29/2020	1983	RET ABN	UG-SERVICE
41776760	GRET	SVC	6/23/2023	1983	RET ABN	UG-SERVICE
40973240	GRET	SVC	12/7/2022	1983	RET ABN	UG-SERVICE
39724957	GRET	SVC	1/31/2022	1983	RET ABN	UG-SERVICE
39439476	GRET	SVC	11/23/2021	1983	RET ABN	UG-SERVICE
42564000	GRET	SVC	1/9/2024	1983	RET ABN	UG-SERVICE
38490764	GRET	SVC	5/14/2021	1983	RET ABN	UG-SERVICE
43245019	GRET	SVC	9/11/2024	1983	RET ABN	UG-SERVICE
41390194	GRET	SVC	3/17/2023	1983	RET ABN	UG-SERVICE
36004758	GRET	SVC	2/10/2020	1983	RET ABN	UG-SERVICE
43600685	GRET	SVC	10/10/2024	1983	RET ABN	UG-SERVICE
36044453	GRET	SVC	2/19/2020	1983	RET ABN	UG-SERVICE
40959765	GRET	SVC	11/28/2022	1983	RET ABN	UG-SERVICE
35849018	GRET	SVC	1/6/2020	1983	RET ABN	UG-SERVICE
42866693	GRET	SVC	3/27/2024	1983	RET ABN	UG-SERVICE
37639162	GRET	SVC	11/17/2020	1983	RET ABN	UG-SERVICE
39169119	GRET	SVC	9/22/2021	1983	RET ABN	UG-SERVICE
40860201	GRET	SVC	11/3/2022	1983	RET ABN	UG-SERVICE
40831308	GRET	SVC	10/17/2022	1983	RET ABN	UG-SERVICE
38894178	GRET	SVC	8/16/2021	1983	RET ABN	UG-SERVICE
38394513	GRET	SVC	4/20/2021	1983	RET ABN	UG-SERVICE
41538513	GRET	SVC	5/2/2023	1983	RET ABN	UG-SERVICE
36402419	GRET	SVC	6/5/2020	1983	RET ABN	UG-SERVICE
39749529	GRET	SVC	2/9/2022	1983	RET ABN	UG-SERVICE
41407380	GRET	SVC	4/2/2024	1983	RET ABN	UG-SERVICE
40457105	GRET	SVC	7/23/2022	1983	RET ABN	UG-SERVICE
42817043	GRET	SVC	3/13/2024	1983	RET ABN	UG-SERVICE
41426175	GRET	SVC	10/18/2023	1983	RET ABN	UG-SERVICE
43028594	GRET	SVC	5/7/2024	1983	RET ABN	UG-SERVICE
37946275	GRET	SVC	12/22/2020	1983	RET ABN	UG-SERVICE
38247963	GRET	SVC	3/17/2021	1983	RET ABN	UG-SERVICE
41818617	GRET	SVC	7/27/2023	1983	RET ABN	UG-SERVICE
41407392	GRET	SVC	4/2/2024	1983	RET ABN	UG-SERVICE
42249669	GRET	SVC	10/18/2023	1983	RET ABN	UG-SERVICE
39368073	GRET	SVC	11/9/2021	1983	RET ABN	UG-SERVICE
36817898	GRET	SVC	9/22/2020	1983	RET ABN	UG-SERVICE
43679595	GRET	SVC	10/21/2024	1983	RET ABN	UG-SERVICE
36360514	GRET	SVC	5/26/2020	1983	RET ABN	UG-SERVICE
41594739	GRET	SVC	5/4/2023	1983	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36951886	GRET	SVC	9/4/2020	1983	RET ABN	UG-SERVICE
41475077	GRET	SVC	10/27/2023	1983	RET ABN	UG-SERVICE
39353250	GRET	SVC	10/27/2021	1983	RET ABN	UG-SERVICE
39234516	GRET	SVC	10/4/2021	1983	RET ABN	UG-SERVICE
36173759	GRET	SVC	6/16/2020	1983	RET ABN	UG-SERVICE
42144356	GRET	SVC	9/24/2023	1983	RET ABN	UG-SERVICE
42206096	GRET	SVC	10/12/2023	1983	RET ABN	UG-SERVICE
41408228	GRET	SVC	4/2/2024	1983	RET ABN	UG-SERVICE
40634724	GRET	SVC	8/30/2022	1983	RET ABN	UG-SERVICE
43416405	GRET	SVC	8/12/2024	1983	RET ABN	UG-SERVICE
35963738	GRET	SVC	2/3/2020	1983	RET ABN	UG-SERVICE
43762376	GRET	SVC	10/31/2024	1983	RET ABN	UG-SERVICE
39858143	GRET	SVC	3/8/2022	1983	RET ABN	UG-SERVICE
36724022	GRET	SVC	8/4/2020	1983	RET ABN	UG-SERVICE
37216830	GRET	SVC	11/2/2020	1983	RET ABN	UG-SERVICE
43423090	GRET	SVC	8/13/2024	1983	RET ABN	UG-SERVICE
41903992	GRET	SVC	7/25/2023	1983	RET ABN	UG-SERVICE
40375226	GRET	SVC	7/5/2022	1983	RET ABN	UG-SERVICE
43923005	GRET	SVC	12/10/2024	1983	RET ABN	UG-SERVICE
42971127	GRET	SVC	4/24/2024	1983	RET ABN	UG-SERVICE
42302679	GRET	SVC	10/30/2023	1983	RET ABN	UG-SERVICE
41407742	GRET	SVC	4/2/2024	1983	RET ABN	UG-SERVICE
41323150	GRET	SVC	2/28/2023	1983	RET ABN	UG-SERVICE
38382270	GRET	SVC	11/22/2021	1983	RET ABN	UG-SERVICE
38378812	GRET	SVC	4/20/2021	1983	RET ABN	UG-SERVICE
43867006	GRET	SVC	11/27/2024	1983	RET ABN	UG-SERVICE
41578426	GRET	SVC	5/1/2023	1983	RET ABN	UG-SERVICE
43424927	GRET	SVC	8/13/2024	1983	RET ABN	UG-SERVICE
43245018	GRET	SVC	9/11/2024	1983	RET ABN	UG-SERVICE
42678903	GRET	SVC	2/5/2024	1983	RET ABN	UG-SERVICE
38192213	GRET	SVC	3/5/2021	1983	RET ABN	UG-SERVICE
40754598	GRET	SVC	10/3/2022	1983	RET ABN	UG-SERVICE
43365783	GRET	SVC	12/12/2024	1983	RET ABN	UG-SERVICE
41969559	GRET	SVC	8/1/2024	1983	RET ABN	UG-SERVICE
38040117	GRET	SVC	5/20/2021	1983	RET ABN	UG-SERVICE
38312994	GRET	SVC	4/7/2021	1983	RET ABN	UG-SERVICE
41904300	GRET	SVC	7/25/2023	1983	RET ABN	UG-SERVICE
38352967	GRET	SVC	2/14/2023	1983	RET ABN	UG-SERVICE
43424839	GRET	SVC	8/13/2024	1983	RET ABN	UG-SERVICE
40266897	GRET	SVC	6/8/2022	1983	RET ABN	UG-SERVICE
38186947	GRET	SVC	3/8/2021	1983	RET ABN	UG-SERVICE
43148395	GRET	SVC	6/4/2024	1983	RET ABN	UG-SERVICE
41901535	GRET	SVC	7/26/2023	1983	RET ABN	UG-SERVICE
39188037	GRET	SVC	10/1/2021	1983	RET ABN	UG-SERVICE
41084278	GRET	SVC	12/21/2022	1983	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43000538	GRET	SVC	5/8/2024	1983	RET ABN	UG-SERVICE
41918001	GRET	SVC	7/21/2023	1983	RET ABN	UG-SERVICE
40492808	GRET	SVC	8/3/2022	1983	RET ABN	UG-SERVICE
40948679	GRET	SVC	11/16/2022	1983	RET ABN	UG-SERVICE
40406351	GRET	SVC	7/11/2022	1983	RET ABN	UG-SERVICE
38274569	GRET	SVC	3/24/2021	1983	RET ABN	UG-SERVICE
35940350	GRET	SVC	1/23/2020	1983	RET ABN	UG-SERVICE
38561319	GRET	SVC	6/1/2021	1983	RET ABN	UG-SERVICE
43108029	GRET	SVC	6/3/2024	1983	RET ABN	UG-SERVICE
35960290	GRET	SVC	1/29/2020	1983	RET ABN	UG-SERVICE
42277980	GRET	SVC	10/23/2023	1983	RET ABN	UG-SERVICE
43108266	GRET	SVC	6/4/2024	1983	RET ABN	UG-SERVICE
41407674	GRET	SVC	4/2/2024	1983	RET ABN	UG-SERVICE
36252614	GRET	SVC	4/27/2020	1983	RET ABN	UG-SERVICE
41464831	GRET	SVC	4/4/2023	1983	RET ABN	UG-SERVICE
43027931	GRET	SVC	5/8/2024	1983	RET ABN	UG-SERVICE
37070146	GRET	SVC	12/9/2020	1983	RET ABN	UG-SERVICE
36862813	GRET	SVC	9/1/2020	1983	RET ABN	UG-SERVICE
36917247	GRET	SVC	9/9/2020	1983	RET ABN	UG-SERVICE
39577167	GRET	SVC	12/10/2021	1984	RET ABN	UG-SERVICE
40202183	GRET	SVC	5/13/2022	1984	RET ABN	UG-SERVICE
38084329	GRET	SVC	2/4/2021	1984	RET ABN	UG-SERVICE
41260666	GRET	SVC	2/8/2023	1984	RET ABN	UG-SERVICE
43312240	GRET	SVC	9/11/2024	1984	RET ABN	UG-SERVICE
43245089	GRET	SVC	9/11/2024	1984	RET ABN	UG-SERVICE
38268354	GRET	SVC	3/25/2021	1984	RET ABN	UG-SERVICE
41694385	GRET	SVC	6/1/2023	1984	RET ABN	UG-SERVICE
38000677	GRET	SVC	1/11/2021	1984	RET ABN	UG-SERVICE
40374657	GRET	SVC	8/6/2022	1984	RET ABN	UG-SERVICE
41000056	GRET	SVC	12/12/2022	1984	RET ABN	UG-SERVICE
38287710	GRET	SVC	3/30/2021	1984	RET ABN	UG-SERVICE
41411260	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
43198365	GRET	SVC	6/17/2024	1984	RET ABN	UG-SERVICE
38435374	GRET	SVC	5/5/2021	1984	RET ABN	UG-SERVICE
40407477	GRET	SVC	7/11/2022	1984	RET ABN	UG-SERVICE
38047952	GRET	SVC	1/19/2021	1984	RET ABN	UG-SERVICE
41579803	GRET	SVC	4/29/2023	1984	RET ABN	UG-SERVICE
36890789	GRET	SVC	9/2/2020	1984	RET ABN	UG-SERVICE
41279382	GRET	SVC	2/24/2023	1984	RET ABN	UG-SERVICE
39662446	GRET	SVC	1/5/2022	1984	RET ABN	UG-SERVICE
37998833	GRET	SVC	1/12/2021	1984	RET ABN	UG-SERVICE
40990212	GRET	SVC	11/23/2022	1984	RET ABN	UG-SERVICE
36167955	GRET	SVC	3/23/2020	1984	RET ABN	UG-SERVICE
39390799	GRET	SVC	12/3/2021	1984	RET ABN	UG-SERVICE
40392685	GRET	SVC	7/7/2022	1984	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41424034	GRET	SVC	10/18/2023	1984	RET ABN	UG-SERVICE
37799668	GRET	SVC	11/25/2020	1984	RET ABN	UG-SERVICE
41713847	GRET	SVC	6/5/2023	1984	RET ABN	UG-SERVICE
40496069	GRET	SVC	8/4/2022	1984	RET ABN	UG-SERVICE
42131793	GRET	SVC	9/20/2023	1984	RET ABN	UG-SERVICE
41179518	GRET	SVC	5/18/2023	1984	RET ABN	UG-SERVICE
41411227	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
43428103	GRET	SVC	8/12/2024	1984	RET ABN	UG-SERVICE
38616144	GRET	SVC	6/14/2021	1984	RET ABN	UG-SERVICE
43245026	GRET	SVC	9/11/2024	1984	RET ABN	UG-SERVICE
41026846	GRET	SVC	10/27/2022	1984	RET ABN	UG-SERVICE
40900985	GRET	SVC	12/3/2022	1984	RET ABN	UG-SERVICE
43245028	GRET	SVC	9/11/2024	1984	RET ABN	UG-SERVICE
36341688	GRET	SVC	5/5/2020	1984	RET ABN	UG-SERVICE
41085375	GRET	SVC	1/11/2023	1984	RET ABN	UG-SERVICE
41411199	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
40458767	GRET	SVC	7/19/2022	1984	RET ABN	UG-SERVICE
43245025	GRET	SVC	9/11/2024	1984	RET ABN	UG-SERVICE
38630801	GRET	SVC	5/3/2021	1984	RET ABN	UG-SERVICE
41977429	GRET	SVC	8/11/2023	1984	RET ABN	UG-SERVICE
40242276	GRET	SVC	6/1/2022	1984	RET ABN	UG-SERVICE
40113736	GRET	SVC	5/2/2022	1984	RET ABN	UG-SERVICE
42827763	GRET	SVC	3/18/2024	1984	RET ABN	UG-SERVICE
41411238	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
38874544	GRET	SVC	8/3/2021	1984	RET ABN	UG-SERVICE
37054166	GRET	SVC	10/13/2020	1984	RET ABN	UG-SERVICE
38392192	GRET	SVC	4/20/2021	1984	RET ABN	UG-SERVICE
40231466	GRET	SVC	5/31/2022	1984	RET ABN	UG-SERVICE
39312451	GRET	SVC	10/25/2021	1984	RET ABN	UG-SERVICE
41179468	GRET	SVC	1/18/2023	1984	RET ABN	UG-SERVICE
42415178	GRET	SVC	12/11/2023	1984	RET ABN	UG-SERVICE
43346953	GRET	SVC	7/22/2024	1984	RET ABN	UG-SERVICE
36177529	GRET	SVC	2/14/2020	1984	RET ABN	UG-SERVICE
36657160	GRET	SVC	7/28/2020	1984	RET ABN	UG-SERVICE
43249480	GRET	SVC	7/3/2024	1984	RET ABN	UG-SERVICE
43312241	GRET	SVC	9/11/2024	1984	RET ABN	UG-SERVICE
41183044	GRET	SVC	1/18/2023	1984	RET ABN	UG-SERVICE
43323078	GRET	SVC	8/13/2024	1984	RET ABN	UG-SERVICE
40395216	GRET	SVC	7/8/2022	1984	RET ABN	UG-SERVICE
39410505	GRET	SVC	11/10/2021	1984	RET ABN	UG-SERVICE
43312119	GRET	SVC	9/11/2024	1984	RET ABN	UG-SERVICE
41411239	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
42112724	GRET	SVC	9/13/2023	1984	RET ABN	UG-SERVICE
38455370	GRET	SVC	5/5/2021	1984	RET ABN	UG-SERVICE
39513647	GRET	SVC	12/6/2021	1984	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41179478	GRET	SVC	1/17/2023	1984	RET ABN	UG-SERVICE
42834268	GRET	SVC	7/23/2024	1984	RET ABN	UG-SERVICE
42068094	GRET	SVC	9/8/2023	1984	RET ABN	UG-SERVICE
41477529	GRET	SVC	4/11/2023	1984	RET ABN	UG-SERVICE
42083819	GRET	SVC	8/28/2023	1984	RET ABN	UG-SERVICE
35996987	GRET	SVC	2/11/2020	1984	RET ABN	UG-SERVICE
41411222	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
38713955	GRET	SVC	7/2/2021	1984	RET ABN	UG-SERVICE
41411220	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
41334096	GRET	SVC	3/6/2023	1984	RET ABN	UG-SERVICE
41969676	GRET	SVC	8/1/2024	1984	RET ABN	UG-SERVICE
41411230	GRET	SVC	4/2/2024	1984	RET ABN	UG-SERVICE
42467159	GRET	SVC	12/22/2023	1984	RET ABN	UG-SERVICE
39501371	GRET	SVC	12/6/2021	1984	RET ABN	UG-SERVICE
43402111	GRET	SVC	8/12/2024	1985	RET ABN	UG-SERVICE
41590369	GRET	SVC	4/19/2023	1985	RET ABN	UG-SERVICE
36185114	GRET	SVC	4/23/2020	1985	RET ABN	UG-SERVICE
43353726	GRET	SVC	12/6/2024	1985	RET ABN	UG-SERVICE
43544497	GRET	SVC	9/11/2024	1985	RET ABN	UG-SERVICE
40693854	GRET	SVC	9/15/2022	1985	RET ABN	UG-SERVICE
40563205	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
41067836	GRET	SVC	1/13/2023	1985	RET ABN	UG-SERVICE
40394467	GRET	SVC	7/9/2022	1985	RET ABN	UG-SERVICE
41297487	GRET	SVC	2/24/2023	1985	RET ABN	UG-SERVICE
37116580	GRET	SVC	10/28/2020	1985	RET ABN	UG-SERVICE
41969668	GRET	SVC	8/1/2024	1985	RET ABN	UG-SERVICE
42427483	GRET	SVC	9/19/2024	1985	RET ABN	UG-SERVICE
41408149	GRET	SVC	4/2/2024	1985	RET ABN	UG-SERVICE
40358442	GRET	SVC	6/17/2022	1985	RET ABN	UG-SERVICE
40316315	GRET	SVC	7/14/2022	1985	RET ABN	UG-SERVICE
42487735	GRET	SVC	7/31/2024	1985	RET ABN	UG-SERVICE
40571823	GRET	SVC	8/15/2022	1985	RET ABN	UG-SERVICE
40563206	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
39401740	GRET	SVC	11/9/2021	1985	RET ABN	UG-SERVICE
41277891	GRET	SVC	3/1/2023	1985	RET ABN	UG-SERVICE
43324303	GRET	SVC	7/26/2024	1985	RET ABN	UG-SERVICE
39809488	GRET	SVC	8/3/2022	1985	RET ABN	UG-SERVICE
41858058	GRET	SVC	7/18/2023	1985	RET ABN	UG-SERVICE
41273675	GRET	SVC	2/15/2023	1985	RET ABN	UG-SERVICE
41408150	GRET	SVC	4/2/2024	1985	RET ABN	UG-SERVICE
40818513	GRET	SVC	10/17/2022	1985	RET ABN	UG-SERVICE
41650434	GRET	SVC	6/22/2023	1985	RET ABN	UG-SERVICE
39553633	GRET	SVC	12/13/2021	1985	RET ABN	UG-SERVICE
43029315	GRET	SVC	5/9/2024	1985	RET ABN	UG-SERVICE
43470857	GRET	SVC	8/23/2024	1985	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36198376	GRET	SVC	4/29/2020	1985	RET ABN	UG-SERVICE
40645039	GRET	SVC	9/3/2022	1985	RET ABN	UG-SERVICE
42921105	GRET	SVC	3/30/2024	1985	RET ABN	UG-SERVICE
43470802	GRET	SVC	8/26/2024	1985	RET ABN	UG-SERVICE
42767882	GRET	SVC	3/4/2024	1985	RET ABN	UG-SERVICE
43268813	GRET	SVC	8/12/2024	1985	RET ABN	UG-SERVICE
35145582	GRET	SVC	1/6/2020	1985	RET ABN	UG-SERVICE
40564946	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
40564985	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
43245041	GRET	SVC	9/19/2024	1985	RET ABN	UG-SERVICE
41430206	GRET	SVC	9/13/2023	1985	RET ABN	UG-SERVICE
40564889	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
43353628	GRET	SVC	11/20/2024	1985	RET ABN	UG-SERVICE
40880404	GRET	SVC	11/3/2022	1985	RET ABN	UG-SERVICE
43353727	GRET	SVC	12/6/2024	1985	RET ABN	UG-SERVICE
40883583	GRET	SVC	11/9/2022	1985	RET ABN	UG-SERVICE
40564947	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
42670285	GRET	SVC	9/19/2024	1985	RET ABN	UG-SERVICE
39556040	GRET	SVC	12/21/2021	1985	RET ABN	UG-SERVICE
40610960	GRET	SVC	8/31/2022	1985	RET ABN	UG-SERVICE
41246619	GRET	SVC	2/8/2023	1985	RET ABN	UG-SERVICE
41467793	GRET	SVC	4/4/2023	1985	RET ABN	UG-SERVICE
41423575	GRET	SVC	10/18/2023	1985	RET ABN	UG-SERVICE
41007066	GRET	SVC	12/6/2022	1985	RET ABN	UG-SERVICE
40901066	GRET	SVC	11/7/2022	1985	RET ABN	UG-SERVICE
41146285	GRET	SVC	1/13/2023	1985	RET ABN	UG-SERVICE
39971213	GRET	SVC	5/16/2022	1985	RET ABN	UG-SERVICE
35968817	GRET	SVC	2/17/2020	1985	RET ABN	UG-SERVICE
41224501	GRET	SVC	3/6/2023	1985	RET ABN	UG-SERVICE
42227665	GRET	SVC	10/31/2023	1985	RET ABN	UG-SERVICE
43226717	GRET	SVC	6/25/2024	1985	RET ABN	UG-SERVICE
43184567	GRET	SVC	6/21/2024	1985	RET ABN	UG-SERVICE
43196207	GRET	SVC	11/25/2024	1985	RET ABN	UG-SERVICE
39464272	GRET	SVC	11/26/2021	1985	RET ABN	UG-SERVICE
43353729	GRET	SVC	12/9/2024	1985	RET ABN	UG-SERVICE
38769233	GRET	SVC	8/30/2021	1985	RET ABN	UG-SERVICE
42246561	GRET	SVC	10/3/2023	1985	RET ABN	UG-SERVICE
38014205	GRET	SVC	1/11/2021	1985	RET ABN	UG-SERVICE
40880416	GRET	SVC	11/3/2022	1985	RET ABN	UG-SERVICE
42236041	GRET	SVC	10/18/2023	1985	RET ABN	UG-SERVICE
41015753	GRET	SVC	12/14/2022	1985	RET ABN	UG-SERVICE
40564888	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
42958105	GRET	SVC	9/19/2024	1985	RET ABN	UG-SERVICE
40564904	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
38373204	GRET	SVC	4/14/2021	1985	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40564714	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
43769717	GRET	SVC	9/19/2024	1985	RET ABN	UG-SERVICE
41430117	GRET	SVC	9/13/2023	1985	RET ABN	UG-SERVICE
43353800	GRET	SVC	12/9/2024	1985	RET ABN	UG-SERVICE
41408077	GRET	SVC	4/2/2024	1985	RET ABN	UG-SERVICE
41067835	GRET	SVC	1/13/2023	1985	RET ABN	UG-SERVICE
35973037	GRET	SVC	2/4/2020	1985	RET ABN	UG-SERVICE
43353809	GRET	SVC	12/11/2024	1985	RET ABN	UG-SERVICE
40577493	GRET	SVC	8/16/2022	1985	RET ABN	UG-SERVICE
40564411	GRET	SVC	8/21/2022	1985	RET ABN	UG-SERVICE
41185583	GRET	SVC	1/17/2023	1985	RET ABN	UG-SERVICE
41843595	GRET	SVC	7/3/2023	1985	RET ABN	UG-SERVICE
40973113	GRET	SVC	11/18/2022	1985	RET ABN	UG-SERVICE
38221177	GRET	SVC	3/13/2021	1985	RET ABN	UG-SERVICE
43604511	GRET	SVC	9/23/2024	1985	RET ABN	UG-SERVICE
42427399	GRET	SVC	9/19/2024	1985	RET ABN	UG-SERVICE
43353739	GRET	SVC	12/3/2024	1985	RET ABN	UG-SERVICE
40900910	GRET	SVC	11/7/2022	1985	RET ABN	UG-SERVICE
38623200	GRET	SVC	6/16/2021	1985	RET ABN	UG-SERVICE
42427101	GRET	SVC	9/19/2024	1985	RET ABN	UG-SERVICE
40856537	GRET	SVC	10/25/2022	1985	RET ABN	UG-SERVICE
42903980	GRET	SVC	4/18/2024	1985	RET ABN	UG-SERVICE
43850749	GRET	SVC	11/18/2024	1985	RET ABN	UG-SERVICE
41411773	GRET	SVC	4/2/2024	1985	RET ABN	UG-SERVICE
41273670	GRET	SVC	2/28/2023	1985	RET ABN	UG-SERVICE
40883590	GRET	SVC	11/9/2022	1985	RET ABN	UG-SERVICE
41409102	GRET	SVC	4/2/2024	1986	RET ABN	UG-SERVICE
36142601	GRET	SVC	3/18/2020	1986	RET ABN	UG-SERVICE
41430201	GRET	SVC	9/13/2023	1986	RET ABN	UG-SERVICE
40778394	GRET	SVC	10/3/2022	1986	RET ABN	UG-SERVICE
43858607	GRET	SVC	11/23/2024	1986	RET ABN	UG-SERVICE
40915198	GRET	SVC	11/9/2022	1986	RET ABN	UG-SERVICE
40641380	GRET	SVC	8/30/2022	1986	RET ABN	UG-SERVICE
38090689	GRET	SVC	2/5/2021	1986	RET ABN	UG-SERVICE
41062439	GRET	SVC	12/14/2022	1986	RET ABN	UG-SERVICE
37335731	GRET	SVC	2/26/2021	1986	RET ABN	UG-SERVICE
43353631	GRET	SVC	11/20/2024	1986	RET ABN	UG-SERVICE
41430200	GRET	SVC	9/13/2023	1986	RET ABN	UG-SERVICE
38562884	GRET	SVC	6/7/2021	1986	RET ABN	UG-SERVICE
41325531	GRET	SVC	3/20/2023	1986	RET ABN	UG-SERVICE
41469915	GRET	SVC	4/4/2023	1986	RET ABN	UG-SERVICE
43353806	GRET	SVC	12/12/2024	1986	RET ABN	UG-SERVICE
42316691	GRET	SVC	4/2/2024	1986	RET ABN	UG-SERVICE
38562880	GRET	SVC	6/7/2021	1986	RET ABN	UG-SERVICE
41556036	GRET	SVC	4/24/2023	1986	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40919248	GRET	SVC	1/6/2023	1986	RET ABN	UG-SERVICE
39335724	GRET	SVC	10/26/2021	1986	RET ABN	UG-SERVICE
42873728	GRET	SVC	4/1/2024	1986	RET ABN	UG-SERVICE
43816202	GRET	SVC	12/9/2024	1986	RET ABN	UG-SERVICE
39923622	GRET	SVC	3/22/2022	1986	RET ABN	UG-SERVICE
39126541	GRET	SVC	9/3/2021	1986	RET ABN	UG-SERVICE
38592110	GRET	SVC	4/17/2021	1986	RET ABN	UG-SERVICE
43353730	GRET	SVC	12/9/2024	1986	RET ABN	UG-SERVICE
43353457	GRET	SVC	11/18/2024	1986	RET ABN	UG-SERVICE
38299044	GRET	SVC	3/31/2021	1986	RET ABN	UG-SERVICE
38352974	GRET	SVC	2/14/2023	1986	RET ABN	UG-SERVICE
40141357	GRET	SVC	5/23/2022	1986	RET ABN	UG-SERVICE
40100832	GRET	SVC	3/18/2022	1986	RET ABN	UG-SERVICE
35960077	GRET	SVC	1/30/2020	1986	RET ABN	UG-SERVICE
40618650	GRET	SVC	8/25/2022	1986	RET ABN	UG-SERVICE
40530414	GRET	SVC	11/7/2022	1986	RET ABN	UG-SERVICE
37325498	GRET	SVC	2/25/2021	1986	RET ABN	UG-SERVICE
41821347	GRET	SVC	6/26/2023	1986	RET ABN	UG-SERVICE
41940034	GRET	SVC	8/6/2023	1986	RET ABN	UG-SERVICE
37561056	GRET	SVC	11/19/2020	1986	RET ABN	UG-SERVICE
43353722	GRET	SVC	12/18/2024	1986	RET ABN	UG-SERVICE
36886014	GRET	SVC	9/1/2020	1986	RET ABN	UG-SERVICE
42048632	GRET	SVC	9/13/2023	1986	RET ABN	UG-SERVICE
41298437	GRET	SVC	8/31/2023	1986	RET ABN	UG-SERVICE
36347720	GRET	SVC	6/29/2020	1986	RET ABN	UG-SERVICE
39335722	GRET	SVC	10/26/2021	1986	RET ABN	UG-SERVICE
43328639	GRET	SVC	7/18/2024	1986	RET ABN	UG-SERVICE
39739689	GRET	SVC	2/10/2022	1986	RET ABN	UG-SERVICE
42203605	GRET	SVC	10/11/2023	1986	RET ABN	UG-SERVICE
40778618	GRET	SVC	10/2/2022	1986	RET ABN	UG-SERVICE
42824956	GRET	SVC	3/13/2024	1986	RET ABN	UG-SERVICE
37115998	GRET	SVC	10/29/2020	1986	RET ABN	UG-SERVICE
41085615	GRET	SVC	12/21/2022	1986	RET ABN	UG-SERVICE
41834505	GRET	SVC	7/21/2023	1986	RET ABN	UG-SERVICE
40303912	GRET	SVC	6/14/2022	1986	RET ABN	UG-SERVICE
42992822	GRET	SVC	4/29/2024	1986	RET ABN	UG-SERVICE
40395529	GRET	SVC	7/7/2022	1986	RET ABN	UG-SERVICE
43324511	GRET	SVC	10/11/2024	1986	RET ABN	UG-SERVICE
41082947	GRET	SVC	12/21/2022	1986	RET ABN	UG-SERVICE
42425594	GRET	SVC	11/30/2023	1986	RET ABN	UG-SERVICE
39177336	GRET	SVC	9/23/2021	1986	RET ABN	UG-SERVICE
42176861	GRET	SVC	10/6/2023	1986	RET ABN	UG-SERVICE
41411501	GRET	SVC	4/2/2024	1986	RET ABN	UG-SERVICE
38441491	GRET	SVC	1/6/2022	1986	RET ABN	UG-SERVICE
38286666	GRET	SVC	3/31/2021	1986	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41959905	GRET	SVC	8/7/2023	1986	RET ABN	UG-SERVICE
40944977	GRET	SVC	11/17/2022	1986	RET ABN	UG-SERVICE
43364933	GRET	SVC	12/4/2024	1986	RET ABN	UG-SERVICE
39930692	GRET	SVC	4/7/2022	1986	RET ABN	UG-SERVICE
43353733	GRET	SVC	12/11/2024	1986	RET ABN	UG-SERVICE
41407743	GRET	SVC	4/2/2024	1986	RET ABN	UG-SERVICE
41185589	GRET	SVC	1/21/2023	1986	RET ABN	UG-SERVICE
38635574	GRET	SVC	6/17/2021	1986	RET ABN	UG-SERVICE
38562886	GRET	SVC	6/7/2021	1986	RET ABN	UG-SERVICE
41325581	GRET	SVC	3/20/2023	1986	RET ABN	UG-SERVICE
41333801	GRET	SVC	3/3/2023	1986	RET ABN	UG-SERVICE
36064582	GRET	SVC	2/26/2020	1986	RET ABN	UG-SERVICE
40124292	GRET	SVC	5/10/2022	1986	RET ABN	UG-SERVICE
41411506	GRET	SVC	4/2/2024	1986	RET ABN	UG-SERVICE
43917756	GRET	SVC	12/9/2024	1986	RET ABN	UG-SERVICE
41555032	GRET	SVC	5/11/2023	1986	RET ABN	UG-SERVICE
37561059	GRET	SVC	11/19/2020	1986	RET ABN	UG-SERVICE
41766898	GRET	SVC	6/20/2023	1986	RET ABN	UG-SERVICE
41129397	GRET	SVC	1/4/2023	1986	RET ABN	UG-SERVICE
35940152	GRET	SVC	1/17/2020	1986	RET ABN	UG-SERVICE
41324834	GRET	SVC	3/20/2023	1986	RET ABN	UG-SERVICE
36485751	GRET	SVC	6/24/2020	1986	RET ABN	UG-SERVICE
37335724	GRET	SVC	2/25/2021	1986	RET ABN	UG-SERVICE
40157835	GRET	SVC	5/17/2022	1986	RET ABN	UG-SERVICE
43353456	GRET	SVC	11/18/2024	1986	RET ABN	UG-SERVICE
39922170	GRET	SVC	3/22/2022	1986	RET ABN	UG-SERVICE
37561057	GRET	SVC	11/19/2020	1986	RET ABN	UG-SERVICE
42954554	GRET	SVC	4/17/2024	1986	RET ABN	UG-SERVICE
41808857	GRET	SVC	6/24/2023	1986	RET ABN	UG-SERVICE
39311633	GRET	SVC	10/27/2021	1986	RET ABN	UG-SERVICE
40656089	GRET	SVC	8/31/2022	1986	RET ABN	UG-SERVICE
42227361	GRET	SVC	10/31/2023	1986	RET ABN	UG-SERVICE
38448870	GRET	SVC	5/5/2021	1986	RET ABN	UG-SERVICE
41427441	GRET	SVC	3/24/2023	1986	RET ABN	UG-SERVICE
37561058	GRET	SVC	12/15/2020	1986	RET ABN	UG-SERVICE
42278935	GRET	SVC	10/27/2023	1986	RET ABN	UG-SERVICE
43353731	GRET	SVC	12/6/2024	1986	RET ABN	UG-SERVICE
38059384	GRET	SVC	1/28/2021	1986	RET ABN	UG-SERVICE
40035473	GRET	SVC	4/19/2022	1986	RET ABN	UG-SERVICE
39930697	GRET	SVC	4/7/2022	1986	RET ABN	UG-SERVICE
41185585	GRET	SVC	1/21/2023	1986	RET ABN	UG-SERVICE
43353805	GRET	SVC	12/12/2024	1986	RET ABN	UG-SERVICE
41325543	GRET	SVC	3/20/2023	1986	RET ABN	UG-SERVICE
40264630	GRET	SVC	6/7/2022	1986	RET ABN	UG-SERVICE
36994489	GRET	SVC	9/28/2020	1986	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41775175	GRET	SVC	6/22/2023	1987	RET ABN	UG-SERVICE
43353620	GRET	SVC	11/22/2024	1987	RET ABN	UG-SERVICE
41289007	GRET	SVC	2/22/2023	1987	RET ABN	UG-SERVICE
36776304	GRET	SVC	8/4/2020	1987	RET ABN	UG-SERVICE
40487118	GRET	SVC	7/25/2022	1987	RET ABN	UG-SERVICE
38272961	GRET	SVC	3/24/2021	1987	RET ABN	UG-SERVICE
38357053	GRET	SVC	2/17/2023	1987	RET ABN	UG-SERVICE
39831464	GRET	SVC	8/3/2022	1987	RET ABN	UG-SERVICE
41283634	GRET	SVC	2/18/2023	1987	RET ABN	UG-SERVICE
40953701	GRET	SVC	11/23/2022	1987	RET ABN	UG-SERVICE
38609048	GRET	SVC	6/10/2021	1987	RET ABN	UG-SERVICE
40124284	GRET	SVC	5/6/2022	1987	RET ABN	UG-SERVICE
42526562	GRET	SVC	1/18/2024	1987	RET ABN	UG-SERVICE
38352978	GRET	SVC	2/17/2023	1987	RET ABN	UG-SERVICE
36949436	GRET	SVC	10/4/2020	1987	RET ABN	UG-SERVICE
38413341	GRET	SVC	8/30/2021	1987	RET ABN	UG-SERVICE
41283623	GRET	SVC	3/15/2023	1987	RET ABN	UG-SERVICE
38542012	GRET	SVC	5/27/2021	1987	RET ABN	UG-SERVICE
41357646	GRET	SVC	3/9/2023	1987	RET ABN	UG-SERVICE
42468286	GRET	SVC	12/12/2023	1987	RET ABN	UG-SERVICE
42870507	GRET	SVC	4/25/2024	1987	RET ABN	UG-SERVICE
43353636	GRET	SVC	12/18/2024	1987	RET ABN	UG-SERVICE
36369313	GRET	SVC	5/27/2020	1987	RET ABN	UG-SERVICE
42671592	GRET	SVC	2/6/2024	1987	RET ABN	UG-SERVICE
39750438	GRET	SVC	5/11/2022	1987	RET ABN	UG-SERVICE
38352927	GRET	SVC	2/17/2023	1987	RET ABN	UG-SERVICE
40976952	GRET	SVC	11/23/2022	1987	RET ABN	UG-SERVICE
42373244	GRET	SVC	11/16/2023	1987	RET ABN	UG-SERVICE
38416005	GRET	SVC	4/26/2021	1987	RET ABN	UG-SERVICE
41509119	GRET	SVC	5/28/2023	1987	RET ABN	UG-SERVICE
39411207	GRET	SVC	11/11/2021	1987	RET ABN	UG-SERVICE
36122361	GRET	SVC	11/5/2020	1987	RET ABN	UG-SERVICE
43241926	GRET	SVC	12/27/2024	1987	RET ABN	UG-SERVICE
43480985	GRET	SVC	10/6/2024	1987	RET ABN	UG-SERVICE
38353001	GRET	SVC	2/14/2023	1987	RET ABN	UG-SERVICE
37973581	GRET	SVC	1/5/2021	1987	RET ABN	UG-SERVICE
36306799	GRET	SVC	6/10/2020	1987	RET ABN	UG-SERVICE
42022519	GRET	SVC	8/19/2023	1987	RET ABN	UG-SERVICE
41283432	GRET	SVC	2/14/2023	1987	RET ABN	UG-SERVICE
42962467	GRET	SVC	4/20/2024	1987	RET ABN	UG-SERVICE
38230875	GRET	SVC	3/16/2021	1987	RET ABN	UG-SERVICE
39093243	GRET	SVC	9/8/2021	1987	RET ABN	UG-SERVICE
36741663	GRET	SVC	8/3/2020	1987	RET ABN	UG-SERVICE
40420448	GRET	SVC	7/11/2022	1987	RET ABN	UG-SERVICE
36992843	GRET	SVC	10/1/2020	1987	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43347390	GRET	SVC	7/24/2024	1987	RET ABN	UG-SERVICE
41283621	GRET	SVC	2/25/2023	1987	RET ABN	UG-SERVICE
38207399	GRET	SVC	3/10/2021	1987	RET ABN	UG-SERVICE
38097603	GRET	SVC	1/29/2021	1987	RET ABN	UG-SERVICE
38887676	GRET	SVC	8/19/2021	1987	RET ABN	UG-SERVICE
43219819	GRET	SVC	6/24/2024	1987	RET ABN	UG-SERVICE
40516609	GRET	SVC	8/5/2022	1987	RET ABN	UG-SERVICE
42313715	GRET	SVC	10/27/2023	1987	RET ABN	UG-SERVICE
42503102	GRET	SVC	12/19/2023	1987	RET ABN	UG-SERVICE
40395538	GRET	SVC	7/6/2022	1987	RET ABN	UG-SERVICE
36602938	GRET	SVC	7/7/2020	1987	RET ABN	UG-SERVICE
39848408	GRET	SVC	6/10/2022	1987	RET ABN	UG-SERVICE
43353621	GRET	SVC	11/22/2024	1987	RET ABN	UG-SERVICE
36955071	GRET	SVC	9/17/2020	1987	RET ABN	UG-SERVICE
40396047	GRET	SVC	7/8/2022	1987	RET ABN	UG-SERVICE
36330971	GRET	SVC	5/19/2020	1987	RET ABN	UG-SERVICE
36122291	GRET	SVC	11/5/2020	1987	RET ABN	UG-SERVICE
39491988	GRET	SVC	12/6/2021	1987	RET ABN	UG-SERVICE
42435909	GRET	SVC	9/19/2024	1987	RET ABN	UG-SERVICE
38083269	GRET	SVC	2/1/2021	1987	RET ABN	UG-SERVICE
40805952	GRET	SVC	10/10/2022	1987	RET ABN	UG-SERVICE
36063444	GRET	SVC	2/24/2020	1987	RET ABN	UG-SERVICE
42007814	GRET	SVC	8/15/2023	1987	RET ABN	UG-SERVICE
43738581	GRET	SVC	10/19/2024	1987	RET ABN	UG-SERVICE
40424138	GRET	SVC	7/12/2022	1987	RET ABN	UG-SERVICE
43481041	GRET	SVC	11/2/2024	1987	RET ABN	UG-SERVICE
41954550	GRET	SVC	8/21/2023	1987	RET ABN	UG-SERVICE
38560872	GRET	SVC	6/1/2021	1987	RET ABN	UG-SERVICE
39750719	GRET	SVC	2/1/2022	1987	RET ABN	UG-SERVICE
41325600	GRET	SVC	3/20/2023	1987	RET ABN	UG-SERVICE
41283330	GRET	SVC	3/15/2023	1987	RET ABN	UG-SERVICE
42962575	GRET	SVC	4/20/2024	1987	RET ABN	UG-SERVICE
41528448	GRET	SVC	5/2/2023	1987	RET ABN	UG-SERVICE
41528299	GRET	SVC	5/2/2023	1987	RET ABN	UG-SERVICE
39497286	GRET	SVC	12/7/2021	1987	RET ABN	UG-SERVICE
39553322	GRET	SVC	12/20/2021	1987	RET ABN	UG-SERVICE
42905534	GRET	SVC	4/1/2024	1987	RET ABN	UG-SERVICE
39671168	GRET	SVC	1/10/2022	1987	RET ABN	UG-SERVICE
40188718	GRET	SVC	5/18/2022	1987	RET ABN	UG-SERVICE
41509377	GRET	SVC	5/5/2023	1987	RET ABN	UG-SERVICE
41176377	GRET	SVC	3/13/2023	1987	RET ABN	UG-SERVICE
36969026	GRET	SVC	12/9/2020	1987	RET ABN	UG-SERVICE
38137182	GRET	SVC	2/18/2021	1987	RET ABN	UG-SERVICE
42487739	GRET	SVC	7/31/2024	1987	RET ABN	UG-SERVICE
37956427	GRET	SVC	12/21/2020	1987	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36630719	GRET	SVC	7/16/2020	1987	RET ABN	UG-SERVICE
42453416	GRET	SVC	12/2/2023	1987	RET ABN	UG-SERVICE
38352547	GRET	SVC	2/14/2023	1987	RET ABN	UG-SERVICE
36009861	GRET	SVC	2/13/2020	1987	RET ABN	UG-SERVICE
43219492	GRET	SVC	6/24/2024	1987	RET ABN	UG-SERVICE
42204420	GRET	SVC	10/9/2023	1987	RET ABN	UG-SERVICE
39418862	GRET	SVC	11/15/2021	1987	RET ABN	UG-SERVICE
40023412	GRET	SVC	3/8/2022	1987	RET ABN	UG-SERVICE
38376390	GRET	SVC	4/19/2021	1987	RET ABN	UG-SERVICE
43832784	GRET	SVC	12/17/2024	1987	RET ABN	UG-SERVICE
41953092	GRET	SVC	8/5/2023	1987	RET ABN	UG-SERVICE
43888925	GRET	SVC	12/2/2024	1987	RET ABN	UG-SERVICE
41497634	GRET	SVC	4/24/2023	1987	RET ABN	UG-SERVICE
36730526	GRET	SVC	8/18/2020	1987	RET ABN	UG-SERVICE
39837092	GRET	SVC	3/2/2022	1987	RET ABN	UG-SERVICE
38356734	GRET	SVC	2/17/2023	1987	RET ABN	UG-SERVICE
43353639	GRET	SVC	11/19/2024	1987	RET ABN	UG-SERVICE
41544094	GRET	SVC	4/24/2023	1987	RET ABN	UG-SERVICE
40640652	GRET	SVC	8/30/2022	1987	RET ABN	UG-SERVICE
40359842	GRET	SVC	6/22/2022	1988	RET ABN	UG-SERVICE
42482398	GRET	SVC	12/13/2023	1988	RET ABN	UG-SERVICE
43529721	GRET	SVC	11/23/2024	1988	RET ABN	UG-SERVICE
41348101	GRET	SVC	3/8/2023	1988	RET ABN	UG-SERVICE
42131094	GRET	SVC	10/2/2023	1988	RET ABN	UG-SERVICE
43424554	GRET	SVC	8/13/2024	1988	RET ABN	UG-SERVICE
41484000	GRET	SVC	4/18/2023	1988	RET ABN	UG-SERVICE
42902358	GRET	SVC	4/10/2024	1988	RET ABN	UG-SERVICE
40802832	GRET	SVC	10/10/2022	1988	RET ABN	UG-SERVICE
38664195	GRET	SVC	6/24/2021	1988	RET ABN	UG-SERVICE
41330583	GRET	SVC	3/6/2023	1988	RET ABN	UG-SERVICE
39726224	GRET	SVC	1/28/2022	1988	RET ABN	UG-SERVICE
43347989	GRET	SVC	7/21/2024	1988	RET ABN	UG-SERVICE
41484001	GRET	SVC	4/18/2023	1988	RET ABN	UG-SERVICE
43344816	GRET	SVC	7/24/2024	1988	RET ABN	UG-SERVICE
43353720	GRET	SVC	11/20/2024	1988	RET ABN	UG-SERVICE
43356661	GRET	SVC	8/5/2024	1988	RET ABN	UG-SERVICE
40690298	GRET	SVC	9/14/2022	1988	RET ABN	UG-SERVICE
38019271	GRET	SVC	1/15/2021	1988	RET ABN	UG-SERVICE
41672952	GRET	SVC	5/24/2023	1988	RET ABN	UG-SERVICE
40318193	GRET	SVC	6/17/2022	1988	RET ABN	UG-SERVICE
42033831	GRET	SVC	8/21/2023	1988	RET ABN	UG-SERVICE
38352353	GRET	SVC	2/14/2023	1988	RET ABN	UG-SERVICE
41317157	GRET	SVC	3/5/2023	1988	RET ABN	UG-SERVICE
40330082	GRET	SVC	6/22/2022	1988	RET ABN	UG-SERVICE
41509368	GRET	SVC	4/18/2023	1988	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38936983	GRET	SVC	9/29/2021	1988	RET ABN	UG-SERVICE
43522111	GRET	SVC	8/20/2024	1988	RET ABN	UG-SERVICE
40312080	GRET	SVC	6/22/2022	1988	RET ABN	UG-SERVICE
36664628	GRET	SVC	7/23/2020	1988	RET ABN	UG-SERVICE
42130053	GRET	SVC	9/20/2023	1988	RET ABN	UG-SERVICE
43230016	GRET	SVC	6/30/2024	1988	RET ABN	UG-SERVICE
39091925	GRET	SVC	9/7/2021	1988	RET ABN	UG-SERVICE
40384102	GRET	SVC	7/5/2022	1988	RET ABN	UG-SERVICE
39904611	GRET	SVC	3/21/2022	1988	RET ABN	UG-SERVICE
38353007	GRET	SVC	2/17/2023	1988	RET ABN	UG-SERVICE
42646567	GRET	SVC	1/29/2024	1988	RET ABN	UG-SERVICE
38352960	GRET	SVC	2/17/2023	1988	RET ABN	UG-SERVICE
39831389	GRET	SVC	8/3/2022	1988	RET ABN	UG-SERVICE
39429947	GRET	SVC	11/18/2021	1988	RET ABN	UG-SERVICE
43417615	GRET	SVC	8/13/2024	1988	RET ABN	UG-SERVICE
43060076	GRET	SVC	5/14/2024	1988	RET ABN	UG-SERVICE
37809721	GRET	SVC	11/21/2020	1988	RET ABN	UG-SERVICE
41483262	GRET	SVC	4/11/2023	1988	RET ABN	UG-SERVICE
41509363	GRET	SVC	4/17/2023	1988	RET ABN	UG-SERVICE
43909688	GRET	SVC	12/19/2024	1988	RET ABN	UG-SERVICE
41484578	GRET	SVC	4/11/2023	1988	RET ABN	UG-SERVICE
38548333	GRET	SVC	6/1/2021	1988	RET ABN	UG-SERVICE
38353011	GRET	SVC	2/14/2023	1988	RET ABN	UG-SERVICE
43028883	GRET	SVC	5/15/2024	1988	RET ABN	UG-SERVICE
38352963	GRET	SVC	2/17/2023	1988	RET ABN	UG-SERVICE
43680029	GRET	SVC	10/31/2024	1988	RET ABN	UG-SERVICE
43868034	GRET	SVC	11/25/2024	1988	RET ABN	UG-SERVICE
43086380	GRET	SVC	5/20/2024	1988	RET ABN	UG-SERVICE
38333914	GRET	SVC	4/8/2021	1988	RET ABN	UG-SERVICE
41339575	GRET	SVC	3/19/2023	1988	RET ABN	UG-SERVICE
38353002	GRET	SVC	2/14/2023	1988	RET ABN	UG-SERVICE
39735614	GRET	SVC	1/27/2022	1988	RET ABN	UG-SERVICE
39831200	GRET	SVC	8/3/2022	1988	RET ABN	UG-SERVICE
36085780	GRET	SVC	2/28/2020	1988	RET ABN	UG-SERVICE
38356735	GRET	SVC	2/17/2023	1988	RET ABN	UG-SERVICE
40461419	GRET	SVC	7/22/2022	1988	RET ABN	UG-SERVICE
41411401	GRET	SVC	4/2/2024	1988	RET ABN	UG-SERVICE
41784366	GRET	SVC	4/25/2024	1988	RET ABN	UG-SERVICE
38352964	GRET	SVC	2/17/2023	1988	RET ABN	UG-SERVICE
40150983	GRET	SVC	4/27/2022	1988	RET ABN	UG-SERVICE
41473285	GRET	SVC	4/6/2023	1988	RET ABN	UG-SERVICE
41480838	GRET	SVC	4/8/2023	1988	RET ABN	UG-SERVICE
42115092	GRET	SVC	9/15/2023	1988	RET ABN	UG-SERVICE
39579981	GRET	SVC	12/27/2021	1988	RET ABN	UG-SERVICE
43070081	GRET	SVC	5/17/2024	1988	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42272964	GRET	SVC	12/21/2023	1988	RET ABN	UG-SERVICE
38536246	GRET	SVC	5/26/2021	1988	RET ABN	UG-SERVICE
41859584	GRET	SVC	7/12/2023	1988	RET ABN	UG-SERVICE
43635664	GRET	SVC	9/27/2024	1988	RET ABN	UG-SERVICE
41485401	GRET	SVC	4/10/2023	1988	RET ABN	UG-SERVICE
40701884	GRET	SVC	9/15/2022	1988	RET ABN	UG-SERVICE
43516694	GRET	SVC	9/4/2024	1988	RET ABN	UG-SERVICE
39843561	GRET	SVC	3/1/2022	1988	RET ABN	UG-SERVICE
36173692	GRET	SVC	3/24/2020	1988	RET ABN	UG-SERVICE
38134101	GRET	SVC	2/15/2021	1988	RET ABN	UG-SERVICE
39654874	GRET	SVC	6/28/2022	1988	RET ABN	UG-SERVICE
41484635	GRET	SVC	4/14/2023	1988	RET ABN	UG-SERVICE
40860141	GRET	SVC	10/25/2022	1988	RET ABN	UG-SERVICE
38776342	GRET	SVC	7/16/2021	1988	RET ABN	UG-SERVICE
38536250	GRET	SVC	5/26/2021	1988	RET ABN	UG-SERVICE
41347538	GRET	SVC	3/17/2023	1988	RET ABN	UG-SERVICE
40353605	GRET	SVC	6/27/2022	1988	RET ABN	UG-SERVICE
41411428	GRET	SVC	11/2/2023	1988	RET ABN	UG-SERVICE
43173752	GRET	SVC	7/17/2024	1988	RET ABN	UG-SERVICE
41655778	GRET	SVC	5/22/2023	1988	RET ABN	UG-SERVICE
38681133	GRET	SVC	6/28/2021	1988	RET ABN	UG-SERVICE
40952592	GRET	SVC	11/17/2022	1988	RET ABN	UG-SERVICE
37809726	GRET	SVC	11/21/2020	1988	RET ABN	UG-SERVICE
42833095	GRET	SVC	7/22/2024	1988	RET ABN	UG-SERVICE
41484824	GRET	SVC	4/18/2023	1988	RET ABN	UG-SERVICE
39390980	GRET	SVC	11/22/2021	1988	RET ABN	UG-SERVICE
42902622	GRET	SVC	4/10/2024	1988	RET ABN	UG-SERVICE
41483261	GRET	SVC	4/11/2023	1988	RET ABN	UG-SERVICE
42878215	GRET	SVC	4/1/2024	1988	RET ABN	UG-SERVICE
43388730	GRET	SVC	8/8/2024	1988	RET ABN	UG-SERVICE
38352939	GRET	SVC	2/17/2023	1988	RET ABN	UG-SERVICE
41339786	GRET	SVC	3/20/2023	1988	RET ABN	UG-SERVICE
39255672	GRET	SVC	10/6/2021	1988	RET ABN	UG-SERVICE
41427597	GRET	SVC	4/11/2023	1988	RET ABN	UG-SERVICE
43907132	GRET	SVC	12/2/2024	1988	RET ABN	UG-SERVICE
40897519	GRET	SVC	10/20/2022	1988	RET ABN	UG-SERVICE
42233736	GRET	SVC	10/17/2023	1988	RET ABN	UG-SERVICE
41183431	GRET	SVC	1/21/2023	1988	RET ABN	UG-SERVICE
36119470	GRET	SVC	3/11/2020	1988	RET ABN	UG-SERVICE
37561228	GRET	SVC	11/18/2020	1988	RET ABN	UG-SERVICE
41728023	GRET	SVC	6/8/2023	1988	RET ABN	UG-SERVICE
41918029	GRET	SVC	7/25/2023	1988	RET ABN	UG-SERVICE
43648056	GRET	SVC	10/8/2024	1988	RET ABN	UG-SERVICE
36330193	GRET	SVC	5/13/2020	1988	RET ABN	UG-SERVICE
41339783	GRET	SVC	3/19/2023	1988	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40371068	GRET	SVC	7/6/2022	1988	RET ABN	UG-SERVICE
38409136	GRET	SVC	5/11/2021	1988	RET ABN	UG-SERVICE
43704279	GRET	SVC	10/18/2024	1988	RET ABN	UG-SERVICE
40005608	GRET	SVC	5/4/2022	1988	RET ABN	UG-SERVICE
38353010	GRET	SVC	2/14/2023	1988	RET ABN	UG-SERVICE
38352962	GRET	SVC	2/17/2023	1988	RET ABN	UG-SERVICE
39979951	GRET	SVC	4/12/2022	1988	RET ABN	UG-SERVICE
40869760	GRET	SVC	11/14/2022	1988	RET ABN	UG-SERVICE
39780198	GRET	SVC	2/10/2022	1988	RET ABN	UG-SERVICE
38353009	GRET	SVC	2/14/2023	1988	RET ABN	UG-SERVICE
42902291	GRET	SVC	4/10/2024	1988	RET ABN	UG-SERVICE
39903260	GRET	SVC	3/17/2022	1988	RET ABN	UG-SERVICE
40360328	GRET	SVC	6/30/2022	1989	RET ABN	UG-SERVICE
40806360	GRET	SVC	10/13/2022	1989	RET ABN	UG-SERVICE
38326366	GRET	SVC	4/7/2021	1989	RET ABN	UG-SERVICE
43826495	GRET	SVC	11/21/2024	1989	RET ABN	UG-SERVICE
36045098	GRET	SVC	2/17/2020	1989	RET ABN	UG-SERVICE
41528451	GRET	SVC	4/26/2023	1989	RET ABN	UG-SERVICE
39657989	GRET	SVC	2/11/2022	1989	RET ABN	UG-SERVICE
41411417	GRET	SVC	11/2/2023	1989	RET ABN	UG-SERVICE
42097440	GRET	SVC	9/12/2023	1989	RET ABN	UG-SERVICE
43711682	GRET	SVC	10/17/2024	1989	RET ABN	UG-SERVICE
42338142	GRET	SVC	11/5/2023	1989	RET ABN	UG-SERVICE
36397955	GRET	SVC	5/31/2020	1989	RET ABN	UG-SERVICE
35965101	GRET	SVC	1/25/2020	1989	RET ABN	UG-SERVICE
43606775	GRET	SVC	9/23/2024	1989	RET ABN	UG-SERVICE
43364867	GRET	SVC	11/15/2024	1989	RET ABN	UG-SERVICE
40524623	GRET	SVC	8/20/2022	1989	RET ABN	UG-SERVICE
42841262	GRET	SVC	3/20/2024	1989	RET ABN	UG-SERVICE
40861132	GRET	SVC	11/3/2022	1989	RET ABN	UG-SERVICE
43889223	GRET	SVC	12/2/2024	1989	RET ABN	UG-SERVICE
38326368	GRET	SVC	4/7/2021	1989	RET ABN	UG-SERVICE
40954338	GRET	SVC	11/25/2022	1989	RET ABN	UG-SERVICE
42672485	GRET	SVC	2/7/2024	1989	RET ABN	UG-SERVICE
39531120	GRET	SVC	11/11/2021	1989	RET ABN	UG-SERVICE
38326367	GRET	SVC	4/7/2021	1989	RET ABN	UG-SERVICE
42833107	GRET	SVC	3/20/2024	1989	RET ABN	UG-SERVICE
39306862	GRET	SVC	10/25/2021	1989	RET ABN	UG-SERVICE
43741572	GRET	SVC	10/23/2024	1989	RET ABN	UG-SERVICE
42338153	GRET	SVC	11/5/2023	1989	RET ABN	UG-SERVICE
40988811	GRET	SVC	11/29/2022	1989	RET ABN	UG-SERVICE
42338155	GRET	SVC	11/5/2023	1989	RET ABN	UG-SERVICE
40974231	GRET	SVC	11/30/2022	1989	RET ABN	UG-SERVICE
40664487	GRET	SVC	9/6/2022	1989	RET ABN	UG-SERVICE
36953283	GRET	SVC	9/17/2020	1989	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36177524	GRET	SVC	2/14/2020	1989	RET ABN	UG-SERVICE
43547702	GRET	SVC	10/21/2024	1989	RET ABN	UG-SERVICE
40845456	GRET	SVC	10/25/2022	1989	RET ABN	UG-SERVICE
36967478	GRET	SVC	9/21/2020	1989	RET ABN	UG-SERVICE
38326365	GRET	SVC	4/7/2021	1989	RET ABN	UG-SERVICE
40361069	GRET	SVC	6/29/2022	1989	RET ABN	UG-SERVICE
36732249	GRET	SVC	8/3/2020	1989	RET ABN	UG-SERVICE
39436428	GRET	SVC	11/18/2021	1989	RET ABN	UG-SERVICE
43324191	GRET	SVC	12/17/2024	1989	RET ABN	UG-SERVICE
42484631	GRET	SVC	12/9/2023	1989	RET ABN	UG-SERVICE
40282633	GRET	SVC	6/8/2022	1989	RET ABN	UG-SERVICE
36918313	GRET	SVC	9/14/2020	1989	RET ABN	UG-SERVICE
40385554	GRET	SVC	7/7/2022	1989	RET ABN	UG-SERVICE
40757102	GRET	SVC	10/3/2022	1989	RET ABN	UG-SERVICE
35985008	GRET	SVC	2/5/2020	1989	RET ABN	UG-SERVICE
36804284	GRET	SVC	9/15/2020	1989	RET ABN	UG-SERVICE
42338143	GRET	SVC	11/5/2023	1989	RET ABN	UG-SERVICE
42921460	GRET	SVC	5/20/2024	1989	RET ABN	UG-SERVICE
42337785	GRET	SVC	11/5/2023	1989	RET ABN	UG-SERVICE
39394755	GRET	SVC	11/9/2021	1989	RET ABN	UG-SERVICE
40282639	GRET	SVC	6/7/2022	1989	RET ABN	UG-SERVICE
40370779	GRET	SVC	7/6/2022	1989	RET ABN	UG-SERVICE
40309945	GRET	SVC	6/15/2022	1989	RET ABN	UG-SERVICE
41635508	GRET	SVC	5/18/2023	1989	RET ABN	UG-SERVICE
41272666	GRET	SVC	2/13/2023	1989	RET ABN	UG-SERVICE
43280669	GRET	SVC	11/25/2024	1989	RET ABN	UG-SERVICE
39423117	GRET	SVC	6/27/2022	1989	RET ABN	UG-SERVICE
37928572	GRET	SVC	1/4/2021	1989	RET ABN	UG-SERVICE
40282857	GRET	SVC	6/13/2022	1989	RET ABN	UG-SERVICE
41768371	GRET	SVC	6/23/2023	1989	RET ABN	UG-SERVICE
36603046	GRET	SVC	7/8/2020	1989	RET ABN	UG-SERVICE
42653097	GRET	SVC	2/6/2024	1989	RET ABN	UG-SERVICE
43930219	GRET	SVC	12/11/2024	1989	RET ABN	UG-SERVICE
40846907	GRET	SVC	10/22/2022	1989	RET ABN	UG-SERVICE
43280670	GRET	SVC	11/25/2024	1989	RET ABN	UG-SERVICE
42338149	GRET	SVC	11/5/2023	1989	RET ABN	UG-SERVICE
42763040	GRET	SVC	3/1/2024	1989	RET ABN	UG-SERVICE
43972041	GRET	SVC	12/23/2024	1989	RET ABN	UG-SERVICE
43195851	GRET	SVC	6/18/2024	1989	RET ABN	UG-SERVICE
42344385	GRET	SVC	11/9/2023	1989	RET ABN	UG-SERVICE
43075712	GRET	SVC	5/24/2024	1989	RET ABN	UG-SERVICE
40973100	GRET	SVC	11/30/2022	1989	RET ABN	UG-SERVICE
36369084	GRET	SVC	5/23/2020	1989	RET ABN	UG-SERVICE
36925972	GRET	SVC	9/14/2020	1989	RET ABN	UG-SERVICE
38532479	GRET	SVC	6/11/2021	1989	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41881436	GRET	SVC	7/18/2023	1989	RET ABN	UG-SERVICE
38813221	GRET	SVC	8/2/2021	1989	RET ABN	UG-SERVICE
41433911	GRET	SVC	3/27/2023	1989	RET ABN	UG-SERVICE
38376263	GRET	SVC	4/20/2021	1989	RET ABN	UG-SERVICE
43506885	GRET	SVC	9/27/2024	1989	RET ABN	UG-SERVICE
38613459	GRET	SVC	8/5/2021	1989	RET ABN	UG-SERVICE
42534000	GRET	SVC	1/4/2024	1990	RET ABN	UG-SERVICE
38413345	GRET	SVC	5/25/2021	1990	RET ABN	UG-SERVICE
41397684	GRET	SVC	3/15/2023	1990	RET ABN	UG-SERVICE
39084496	GRET	SVC	9/7/2021	1990	RET ABN	UG-SERVICE
41427450	GRET	SVC	3/21/2023	1990	RET ABN	UG-SERVICE
43600748	GRET	SVC	9/23/2024	1990	RET ABN	UG-SERVICE
41543906	GRET	SVC	4/24/2023	1990	RET ABN	UG-SERVICE
42236828	GRET	SVC	10/16/2023	1990	RET ABN	UG-SERVICE
43353453	GRET	SVC	11/21/2024	1990	RET ABN	UG-SERVICE
40981807	GRET	SVC	11/28/2022	1990	RET ABN	UG-SERVICE
41129074	GRET	SVC	1/5/2023	1990	RET ABN	UG-SERVICE
40491493	GRET	SVC	7/27/2022	1990	RET ABN	UG-SERVICE
36199499	GRET	SVC	4/22/2020	1990	RET ABN	UG-SERVICE
40978232	GRET	SVC	11/28/2022	1990	RET ABN	UG-SERVICE
36125170	GRET	SVC	6/13/2020	1990	RET ABN	UG-SERVICE
40981882	GRET	SVC	11/28/2022	1990	RET ABN	UG-SERVICE
43398030	GRET	SVC	8/6/2024	1990	RET ABN	UG-SERVICE
41447891	GRET	SVC	3/30/2023	1990	RET ABN	UG-SERVICE
43330190	GRET	SVC	7/18/2024	1990	RET ABN	UG-SERVICE
40278530	GRET	SVC	6/10/2022	1990	RET ABN	UG-SERVICE
38698665	GRET	SVC	8/10/2021	1990	RET ABN	UG-SERVICE
40507607	GRET	SVC	9/9/2022	1990	RET ABN	UG-SERVICE
42823916	GRET	SVC	4/15/2024	1990	RET ABN	UG-SERVICE
36281347	GRET	SVC	4/29/2020	1990	RET ABN	UG-SERVICE
41320813	GRET	SVC	2/28/2023	1990	RET ABN	UG-SERVICE
41767341	GRET	SVC	6/19/2023	1990	RET ABN	UG-SERVICE
41447525	GRET	SVC	3/30/2023	1990	RET ABN	UG-SERVICE
43765822	GRET	SVC	10/30/2024	1990	RET ABN	UG-SERVICE
40621518	GRET	SVC	8/31/2022	1990	RET ABN	UG-SERVICE
40594519	GRET	SVC	9/16/2022	1990	RET ABN	UG-SERVICE
39378868	GRET	SVC	12/2/2021	1990	RET ABN	UG-SERVICE
42020315	GRET	SVC	8/21/2023	1990	RET ABN	UG-SERVICE
38517629	GRET	SVC	4/12/2021	1990	RET ABN	UG-SERVICE
43353452	GRET	SVC	11/20/2024	1990	RET ABN	UG-SERVICE
40075583	GRET	SVC	4/26/2022	1990	RET ABN	UG-SERVICE
40347345	GRET	SVC	6/27/2022	1990	RET ABN	UG-SERVICE
42362055	GRET	SVC	11/9/2023	1990	RET ABN	UG-SERVICE
40658820	GRET	SVC	8/31/2022	1990	RET ABN	UG-SERVICE
40222107	GRET	SVC	5/18/2022	1990	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43480988	GRET	SVC	11/8/2024	1990	RET ABN	UG-SERVICE
38283684	GRET	SVC	3/29/2021	1990	RET ABN	UG-SERVICE
43486706	GRET	SVC	8/26/2024	1990	RET ABN	UG-SERVICE
36998793	GRET	SVC	9/30/2020	1990	RET ABN	UG-SERVICE
37810891	GRET	SVC	11/25/2020	1990	RET ABN	UG-SERVICE
41447893	GRET	SVC	3/30/2023	1990	RET ABN	UG-SERVICE
43084799	GRET	SVC	5/22/2024	1990	RET ABN	UG-SERVICE
37424443	GRET	SVC	11/24/2020	1990	RET ABN	UG-SERVICE
36758848	GRET	SVC	7/27/2020	1990	RET ABN	UG-SERVICE
40896368	GRET	SVC	11/21/2022	1990	RET ABN	UG-SERVICE
41920514	GRET	SVC	8/4/2023	1990	RET ABN	UG-SERVICE
41447165	GRET	SVC	3/28/2023	1990	RET ABN	UG-SERVICE
41295790	GRET	SVC	2/20/2023	1990	RET ABN	UG-SERVICE
42163979	GRET	SVC	9/26/2023	1990	RET ABN	UG-SERVICE
40223284	GRET	SVC	6/5/2022	1990	RET ABN	UG-SERVICE
41283320	GRET	SVC	2/15/2023	1990	RET ABN	UG-SERVICE
43353801	GRET	SVC	12/3/2024	1990	RET ABN	UG-SERVICE
42992788	GRET	SVC	4/29/2024	1990	RET ABN	UG-SERVICE
41324893	GRET	SVC	2/28/2023	1990	RET ABN	UG-SERVICE
42045510	GRET	SVC	9/5/2023	1990	RET ABN	UG-SERVICE
40266841	GRET	SVC	7/5/2022	1990	RET ABN	UG-SERVICE
41568304	GRET	SVC	4/23/2023	1990	RET ABN	UG-SERVICE
42534948	GRET	SVC	2/5/2024	1990	RET ABN	UG-SERVICE
38352930	GRET	SVC	2/17/2023	1990	RET ABN	UG-SERVICE
36051642	GRET	SVC	2/22/2020	1990	RET ABN	UG-SERVICE
38441385	GRET	SVC	1/6/2022	1990	RET ABN	UG-SERVICE
41544072	GRET	SVC	4/26/2023	1990	RET ABN	UG-SERVICE
40223294	GRET	SVC	5/31/2022	1990	RET ABN	UG-SERVICE
41015444	GRET	SVC	12/16/2022	1990	RET ABN	UG-SERVICE
41428821	GRET	SVC	3/28/2023	1990	RET ABN	UG-SERVICE
43203102	GRET	SVC	6/24/2024	1990	RET ABN	UG-SERVICE
38697861	GRET	SVC	7/7/2021	1990	RET ABN	UG-SERVICE
38044256	GRET	SVC	1/16/2021	1990	RET ABN	UG-SERVICE
42745580	GRET	SVC	3/5/2024	1990	RET ABN	UG-SERVICE
41447886	GRET	SVC	3/30/2023	1990	RET ABN	UG-SERVICE
38050812	GRET	SVC	1/25/2021	1990	RET ABN	UG-SERVICE
41317496	GRET	SVC	3/3/2023	1990	RET ABN	UG-SERVICE
40241979	GRET	SVC	5/21/2022	1990	RET ABN	UG-SERVICE
40514680	GRET	SVC	7/30/2022	1990	RET ABN	UG-SERVICE
41418432	GRET	SVC	3/20/2023	1990	RET ABN	UG-SERVICE
41398461	GRET	SVC	3/13/2023	1990	RET ABN	UG-SERVICE
39932756	GRET	SVC	4/1/2022	1990	RET ABN	UG-SERVICE
36108718	GRET	SVC	3/10/2020	1990	RET ABN	UG-SERVICE
41411510	GRET	SVC	4/2/2024	1990	RET ABN	UG-SERVICE
42320050	GRET	SVC	11/3/2023	1990	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41419857	GRET	SVC	3/21/2023	1990	RET ABN	UG-SERVICE
43634479	GRET	SVC	10/3/2024	1990	RET ABN	UG-SERVICE
42449339	GRET	SVC	12/5/2023	1990	RET ABN	UG-SERVICE
41896733	GRET	SVC	7/18/2023	1990	RET ABN	UG-SERVICE
41425508	GRET	SVC	3/31/2023	1990	RET ABN	UG-SERVICE
41273858	GRET	SVC	2/14/2023	1990	RET ABN	UG-SERVICE
40334904	GRET	SVC	10/6/2022	1990	RET ABN	UG-SERVICE
41282918	GRET	SVC	2/15/2023	1990	RET ABN	UG-SERVICE
42226640	GRET	SVC	10/16/2023	1990	RET ABN	UG-SERVICE
43318037	GRET	SVC	8/12/2024	1990	RET ABN	UG-SERVICE
40683519	GRET	SVC	9/14/2022	1990	RET ABN	UG-SERVICE
39161965	GRET	SVC	9/13/2021	1990	RET ABN	UG-SERVICE
41235835	GRET	SVC	2/4/2023	1990	RET ABN	UG-SERVICE
43268084	GRET	SVC	7/9/2024	1990	RET ABN	UG-SERVICE
41961264	GRET	SVC	8/8/2023	1990	RET ABN	UG-SERVICE
42361115	GRET	SVC	11/13/2023	1990	RET ABN	UG-SERVICE
41670040	GRET	SVC	5/20/2023	1990	RET ABN	UG-SERVICE
40557697	GRET	SVC	8/19/2022	1990	RET ABN	UG-SERVICE
43529746	GRET	SVC	11/7/2024	1990	RET ABN	UG-SERVICE
36061274	GRET	SVC	2/22/2020	1990	RET ABN	UG-SERVICE
41288524	GRET	SVC	3/17/2023	1990	RET ABN	UG-SERVICE
40400410	GRET	SVC	7/14/2022	1990	RET ABN	UG-SERVICE
36626255	GRET	SVC	6/29/2020	1990	RET ABN	UG-SERVICE
37951728	GRET	SVC	12/22/2020	1990	RET ABN	UG-SERVICE
38168857	GRET	SVC	2/24/2021	1990	RET ABN	UG-SERVICE
35960295	GRET	SVC	1/29/2020	1990	RET ABN	UG-SERVICE
37847687	GRET	SVC	12/1/2020	1990	RET ABN	UG-SERVICE
39337455	GRET	SVC	10/26/2021	1990	RET ABN	UG-SERVICE
43210020	GRET	SVC	7/1/2024	1990	RET ABN	UG-SERVICE
40807464	GRET	SVC	10/11/2022	1990	RET ABN	UG-SERVICE
37145164	GRET	SVC	10/26/2020	1990	RET ABN	UG-SERVICE
43328055	GRET	SVC	7/15/2024	1990	RET ABN	UG-SERVICE
41418436	GRET	SVC	3/20/2023	1990	RET ABN	UG-SERVICE
41418538	GRET	SVC	3/20/2023	1990	RET ABN	UG-SERVICE
43353808	GRET	SVC	12/17/2024	1990	RET ABN	UG-SERVICE
43353807	GRET	SVC	12/17/2024	1990	RET ABN	UG-SERVICE
39893102	GRET	SVC	7/11/2022	1991	RET ABN	UG-SERVICE
36409445	GRET	SVC	6/8/2020	1991	RET ABN	UG-SERVICE
42430283	GRET	SVC	11/26/2023	1991	RET ABN	UG-SERVICE
40327028	GRET	SVC	6/21/2022	1991	RET ABN	UG-SERVICE
35983294	GRET	SVC	3/2/2020	1991	RET ABN	UG-SERVICE
37914954	GRET	SVC	12/17/2020	1991	RET ABN	UG-SERVICE
43481043	GRET	SVC	10/25/2024	1991	RET ABN	UG-SERVICE
42353448	GRET	SVC	11/13/2023	1991	RET ABN	UG-SERVICE
41144784	GRET	SVC	1/11/2023	1991	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43713034	GRET	SVC	10/21/2024	1991	RET ABN	UG-SERVICE
36625393	GRET	SVC	7/11/2020	1991	RET ABN	UG-SERVICE
38357401	GRET	SVC	2/14/2023	1991	RET ABN	UG-SERVICE
38647500	GRET	SVC	6/22/2021	1991	RET ABN	UG-SERVICE
43318170	GRET	SVC	8/9/2024	1991	RET ABN	UG-SERVICE
40860216	GRET	SVC	11/3/2022	1991	RET ABN	UG-SERVICE
42904493	GRET	SVC	4/7/2024	1991	RET ABN	UG-SERVICE
41733397	GRET	SVC	6/12/2023	1991	RET ABN	UG-SERVICE
43345647	GRET	SVC	7/22/2024	1991	RET ABN	UG-SERVICE
43529732	GRET	SVC	11/22/2024	1991	RET ABN	UG-SERVICE
38352828	GRET	SVC	2/17/2023	1991	RET ABN	UG-SERVICE
40883285	GRET	SVC	10/30/2022	1991	RET ABN	UG-SERVICE
40571828	GRET	SVC	8/16/2022	1991	RET ABN	UG-SERVICE
36962757	GRET	SVC	9/21/2020	1991	RET ABN	UG-SERVICE
36356345	GRET	SVC	5/18/2020	1991	RET ABN	UG-SERVICE
36199822	GRET	SVC	5/1/2020	1991	RET ABN	UG-SERVICE
41222791	GRET	SVC	1/31/2023	1991	RET ABN	UG-SERVICE
36511655	GRET	SVC	6/18/2020	1991	RET ABN	UG-SERVICE
41304549	GRET	SVC	3/6/2023	1991	RET ABN	UG-SERVICE
41428831	GRET	SVC	3/23/2023	1991	RET ABN	UG-SERVICE
38913622	GRET	SVC	8/9/2021	1991	RET ABN	UG-SERVICE
40858949	GRET	SVC	10/24/2022	1991	RET ABN	UG-SERVICE
41144636	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
41803088	GRET	SVC	7/7/2023	1991	RET ABN	UG-SERVICE
42112489	GRET	SVC	9/12/2023	1991	RET ABN	UG-SERVICE
39544010	GRET	SVC	12/14/2021	1991	RET ABN	UG-SERVICE
40990263	GRET	SVC	11/18/2022	1991	RET ABN	UG-SERVICE
42953403	GRET	SVC	4/17/2024	1991	RET ABN	UG-SERVICE
41144491	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
40949368	GRET	SVC	11/16/2022	1991	RET ABN	UG-SERVICE
41582634	GRET	SVC	5/3/2023	1991	RET ABN	UG-SERVICE
40190769	GRET	SVC	5/21/2022	1991	RET ABN	UG-SERVICE
43329557	GRET	SVC	7/19/2024	1991	RET ABN	UG-SERVICE
36659846	GRET	SVC	7/21/2020	1991	RET ABN	UG-SERVICE
38938944	GRET	SVC	8/15/2021	1991	RET ABN	UG-SERVICE
43000634	GRET	SVC	5/23/2024	1991	RET ABN	UG-SERVICE
40883588	GRET	SVC	11/9/2022	1991	RET ABN	UG-SERVICE
38352829	GRET	SVC	2/17/2023	1991	RET ABN	UG-SERVICE
36683352	GRET	SVC	7/27/2020	1991	RET ABN	UG-SERVICE
41321352	GRET	SVC	3/16/2023	1991	RET ABN	UG-SERVICE
41144604	GRET	SVC	1/7/2023	1991	RET ABN	UG-SERVICE
36363706	GRET	SVC	5/19/2020	1991	RET ABN	UG-SERVICE
41144755	GRET	SVC	1/11/2023	1991	RET ABN	UG-SERVICE
40991251	GRET	SVC	11/18/2022	1991	RET ABN	UG-SERVICE
37958000	GRET	SVC	12/29/2020	1991	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42105047	GRET	SVC	9/13/2023	1991	RET ABN	UG-SERVICE
43529729	GRET	SVC	12/22/2024	1991	RET ABN	UG-SERVICE
41142029	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
41482052	GRET	SVC	4/9/2023	1991	RET ABN	UG-SERVICE
42462806	GRET	SVC	12/9/2023	1991	RET ABN	UG-SERVICE
43364876	GRET	SVC	12/12/2024	1991	RET ABN	UG-SERVICE
36267690	GRET	SVC	3/24/2020	1991	RET ABN	UG-SERVICE
36302290	GRET	SVC	5/5/2020	1991	RET ABN	UG-SERVICE
41424367	GRET	SVC	3/24/2023	1991	RET ABN	UG-SERVICE
41143808	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
36234314	GRET	SVC	5/15/2020	1991	RET ABN	UG-SERVICE
43260047	GRET	SVC	8/12/2024	1991	RET ABN	UG-SERVICE
42872613	GRET	SVC	4/2/2024	1991	RET ABN	UG-SERVICE
38603828	GRET	SVC	6/15/2021	1991	RET ABN	UG-SERVICE
41015443	GRET	SVC	12/4/2022	1991	RET ABN	UG-SERVICE
39330552	GRET	SVC	10/26/2021	1991	RET ABN	UG-SERVICE
41321340	GRET	SVC	3/15/2023	1991	RET ABN	UG-SERVICE
41143388	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
41321345	GRET	SVC	3/15/2023	1991	RET ABN	UG-SERVICE
42873152	GRET	SVC	4/2/2024	1991	RET ABN	UG-SERVICE
41421864	GRET	SVC	3/23/2023	1991	RET ABN	UG-SERVICE
39543628	GRET	SVC	12/14/2021	1991	RET ABN	UG-SERVICE
42195837	GRET	SVC	10/9/2023	1991	RET ABN	UG-SERVICE
38906642	GRET	SVC	8/31/2021	1991	RET ABN	UG-SERVICE
40302997	GRET	SVC	6/13/2022	1991	RET ABN	UG-SERVICE
41321354	GRET	SVC	3/16/2023	1991	RET ABN	UG-SERVICE
40859701	GRET	SVC	11/30/2022	1991	RET ABN	UG-SERVICE
41065389	GRET	SVC	12/14/2022	1991	RET ABN	UG-SERVICE
40860841	GRET	SVC	10/28/2022	1991	RET ABN	UG-SERVICE
43529375	GRET	SVC	11/24/2024	1991	RET ABN	UG-SERVICE
37251258	GRET	SVC	11/2/2020	1991	RET ABN	UG-SERVICE
43857177	GRET	SVC	11/20/2024	1991	RET ABN	UG-SERVICE
42145812	GRET	SVC	9/25/2023	1991	RET ABN	UG-SERVICE
42216031	GRET	SVC	10/10/2023	1991	RET ABN	UG-SERVICE
38352827	GRET	SVC	2/17/2023	1991	RET ABN	UG-SERVICE
38098231	GRET	SVC	2/7/2021	1991	RET ABN	UG-SERVICE
43329564	GRET	SVC	7/19/2024	1991	RET ABN	UG-SERVICE
38326248	GRET	SVC	4/9/2021	1991	RET ABN	UG-SERVICE
40036272	GRET	SVC	4/19/2022	1991	RET ABN	UG-SERVICE
41144462	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
41083867	GRET	SVC	12/21/2022	1991	RET ABN	UG-SERVICE
41877226	GRET	SVC	7/17/2023	1991	RET ABN	UG-SERVICE
43324307	GRET	SVC	10/17/2024	1991	RET ABN	UG-SERVICE
42562269	GRET	SVC	1/12/2024	1991	RET ABN	UG-SERVICE
41320413	GRET	SVC	3/3/2023	1991	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42025605	GRET	SVC	8/22/2023	1991	RET ABN	UG-SERVICE
39743323	GRET	SVC	1/27/2022	1991	RET ABN	UG-SERVICE
40775520	GRET	SVC	10/4/2022	1991	RET ABN	UG-SERVICE
36016960	GRET	SVC	2/11/2020	1991	RET ABN	UG-SERVICE
40899890	GRET	SVC	11/8/2022	1991	RET ABN	UG-SERVICE
40395847	GRET	SVC	7/6/2022	1991	RET ABN	UG-SERVICE
40571973	GRET	SVC	8/16/2022	1991	RET ABN	UG-SERVICE
39657988	GRET	SVC	2/5/2022	1991	RET ABN	UG-SERVICE
41321122	GRET	SVC	3/16/2023	1991	RET ABN	UG-SERVICE
43358252	GRET	SVC	7/19/2024	1991	RET ABN	UG-SERVICE
40162498	GRET	SVC	5/18/2022	1991	RET ABN	UG-SERVICE
41182810	GRET	SVC	1/18/2023	1991	RET ABN	UG-SERVICE
36487200	GRET	SVC	6/18/2020	1991	RET ABN	UG-SERVICE
41143459	GRET	SVC	1/11/2023	1991	RET ABN	UG-SERVICE
41464722	GRET	SVC	4/3/2023	1991	RET ABN	UG-SERVICE
40868641	GRET	SVC	11/3/2022	1991	RET ABN	UG-SERVICE
35844797	GRET	SVC	2/4/2020	1991	RET ABN	UG-SERVICE
38352830	GRET	SVC	2/17/2023	1991	RET ABN	UG-SERVICE
38402399	GRET	SVC	4/23/2021	1991	RET ABN	UG-SERVICE
41482054	GRET	SVC	4/8/2023	1991	RET ABN	UG-SERVICE
36301314	GRET	SVC	5/5/2020	1991	RET ABN	UG-SERVICE
41064586	GRET	SVC	12/15/2022	1991	RET ABN	UG-SERVICE
43325562	GRET	SVC	7/15/2024	1991	RET ABN	UG-SERVICE
36597389	GRET	SVC	6/27/2020	1991	RET ABN	UG-SERVICE
40883299	GRET	SVC	10/30/2022	1991	RET ABN	UG-SERVICE
41065407	GRET	SVC	12/14/2022	1991	RET ABN	UG-SERVICE
41144071	GRET	SVC	1/9/2023	1991	RET ABN	UG-SERVICE
41247249	GRET	SVC	2/7/2023	1991	RET ABN	UG-SERVICE
41143964	GRET	SVC	1/10/2023	1991	RET ABN	UG-SERVICE
39544351	GRET	SVC	12/13/2021	1991	RET ABN	UG-SERVICE
41143554	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
38146655	GRET	SVC	2/17/2021	1991	RET ABN	UG-SERVICE
36901871	GRET	SVC	9/9/2020	1991	RET ABN	UG-SERVICE
41144319	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
36283868	GRET	SVC	5/12/2020	1991	RET ABN	UG-SERVICE
41675410	GRET	SVC	5/30/2023	1991	RET ABN	UG-SERVICE
43329720	GRET	SVC	7/19/2024	1991	RET ABN	UG-SERVICE
36356885	GRET	SVC	5/18/2020	1991	RET ABN	UG-SERVICE
39874650	GRET	SVC	3/11/2022	1991	RET ABN	UG-SERVICE
38441559	GRET	SVC	1/6/2022	1991	RET ABN	UG-SERVICE
38480827	GRET	SVC	5/11/2021	1991	RET ABN	UG-SERVICE
37935135	GRET	SVC	12/19/2020	1991	RET ABN	UG-SERVICE
42588325	GRET	SVC	1/24/2024	1991	RET ABN	UG-SERVICE
41143738	GRET	SVC	7/31/2023	1991	RET ABN	UG-SERVICE
43955127	GRET	SVC	12/30/2024	1991	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41321353	GRET	SVC	3/16/2023	1991	RET ABN	UG-SERVICE
40752909	GRET	SVC	9/26/2022	1991	RET ABN	UG-SERVICE
41144786	GRET	SVC	1/11/2023	1991	RET ABN	UG-SERVICE
36739594	GRET	SVC	8/4/2020	1991	RET ABN	UG-SERVICE
38146652	GRET	SVC	2/17/2021	1991	RET ABN	UG-SERVICE
42425332	GRET	SVC	5/29/2024	1991	RET ABN	UG-SERVICE
40142745	GRET	SVC	5/11/2022	1991	RET ABN	UG-SERVICE
43318485	GRET	SVC	9/26/2024	1991	RET ABN	UG-SERVICE
41428828	GRET	SVC	3/23/2023	1991	RET ABN	UG-SERVICE
38146653	GRET	SVC	2/17/2021	1991	RET ABN	UG-SERVICE
41479993	GRET	SVC	4/10/2023	1991	RET ABN	UG-SERVICE
43481258	GRET	SVC	11/1/2024	1991	RET ABN	UG-SERVICE
41139511	GRET	SVC	1/13/2023	1991	RET ABN	UG-SERVICE
42187329	GRET	SVC	10/5/2023	1991	RET ABN	UG-SERVICE
40883288	GRET	SVC	10/30/2022	1991	RET ABN	UG-SERVICE
38232683	GRET	SVC	3/15/2021	1991	RET ABN	UG-SERVICE
41321129	GRET	SVC	3/15/2023	1991	RET ABN	UG-SERVICE
41430970	GRET	SVC	3/29/2023	1992	RET ABN	UG-SERVICE
43462114	GRET	SVC	9/3/2024	1992	RET ABN	UG-SERVICE
41411236	GRET	SVC	4/2/2024	1992	RET ABN	UG-SERVICE
41324884	GRET	SVC	3/1/2023	1992	RET ABN	UG-SERVICE
41243169	GRET	SVC	2/5/2023	1992	RET ABN	UG-SERVICE
41032256	GRET	SVC	12/15/2022	1992	RET ABN	UG-SERVICE
43481091	GRET	SVC	10/31/2024	1992	RET ABN	UG-SERVICE
40286467	GRET	SVC	6/11/2022	1992	RET ABN	UG-SERVICE
37291022	GRET	SVC	11/9/2020	1992	RET ABN	UG-SERVICE
40385556	GRET	SVC	7/6/2022	1992	RET ABN	UG-SERVICE
39154112	GRET	SVC	9/20/2021	1992	RET ABN	UG-SERVICE
43717068	GRET	SVC	10/25/2024	1992	RET ABN	UG-SERVICE
41180365	GRET	SVC	1/19/2023	1992	RET ABN	UG-SERVICE
42520346	GRET	SVC	12/26/2023	1992	RET ABN	UG-SERVICE
38910599	GRET	SVC	8/11/2021	1992	RET ABN	UG-SERVICE
37843371	GRET	SVC	11/30/2020	1992	RET ABN	UG-SERVICE
40827593	GRET	SVC	10/17/2022	1992	RET ABN	UG-SERVICE
40952735	GRET	SVC	11/18/2022	1992	RET ABN	UG-SERVICE
43481183	GRET	SVC	11/20/2024	1992	RET ABN	UG-SERVICE
39803732	GRET	SVC	3/22/2022	1992	RET ABN	UG-SERVICE
40813403	GRET	SVC	10/15/2022	1992	RET ABN	UG-SERVICE
41222784	GRET	SVC	3/3/2023	1992	RET ABN	UG-SERVICE
37887981	GRET	SVC	12/5/2020	1992	RET ABN	UG-SERVICE
43318038	GRET	SVC	7/29/2024	1992	RET ABN	UG-SERVICE
40468999	GRET	SVC	7/22/2022	1992	RET ABN	UG-SERVICE
41205592	GRET	SVC	1/27/2023	1992	RET ABN	UG-SERVICE
40395840	GRET	SVC	7/6/2022	1992	RET ABN	UG-SERVICE
39476682	GRET	SVC	11/26/2021	1992	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41483269	GRET	SVC	4/13/2023	1992	RET ABN	UG-SERVICE
41143413	GRET	SVC	1/10/2023	1992	RET ABN	UG-SERVICE
41144751	GRET	SVC	1/12/2023	1992	RET ABN	UG-SERVICE
43902683	GRET	SVC	12/5/2024	1992	RET ABN	UG-SERVICE
36881227	GRET	SVC	8/29/2020	1992	RET ABN	UG-SERVICE
36834327	GRET	SVC	8/27/2020	1992	RET ABN	UG-SERVICE
40831607	GRET	SVC	10/19/2022	1992	RET ABN	UG-SERVICE
43529748	GRET	SVC	12/4/2024	1992	RET ABN	UG-SERVICE
41179464	GRET	SVC	1/18/2023	1992	RET ABN	UG-SERVICE
41937404	GRET	SVC	8/1/2023	1992	RET ABN	UG-SERVICE
42265988	GRET	SVC	10/23/2023	1992	RET ABN	UG-SERVICE
40867634	GRET	SVC	11/3/2022	1992	RET ABN	UG-SERVICE
39461251	GRET	SVC	11/24/2021	1992	RET ABN	UG-SERVICE
43591085	GRET	SVC	9/16/2024	1992	RET ABN	UG-SERVICE
43627285	GRET	SVC	9/30/2024	1992	RET ABN	UG-SERVICE
41873064	GRET	SVC	7/11/2023	1992	RET ABN	UG-SERVICE
41347204	GRET	SVC	3/6/2023	1992	RET ABN	UG-SERVICE
39487063	GRET	SVC	12/20/2021	1992	RET ABN	UG-SERVICE
41144816	GRET	SVC	1/12/2023	1992	RET ABN	UG-SERVICE
41420314	GRET	SVC	3/24/2023	1992	RET ABN	UG-SERVICE
42277344	GRET	SVC	10/23/2023	1992	RET ABN	UG-SERVICE
43899043	GRET	SVC	12/4/2024	1992	RET ABN	UG-SERVICE
42760798	GRET	SVC	8/1/2024	1992	RET ABN	UG-SERVICE
38747325	GRET	SVC	7/20/2021	1992	RET ABN	UG-SERVICE
35865564	GRET	SVC	1/4/2020	1992	RET ABN	UG-SERVICE
42004114	GRET	SVC	8/16/2023	1992	RET ABN	UG-SERVICE
41242848	GRET	SVC	3/27/2023	1992	RET ABN	UG-SERVICE
38315072	GRET	SVC	2/26/2021	1992	RET ABN	UG-SERVICE
42506615	GRET	SVC	12/27/2023	1992	RET ABN	UG-SERVICE
42658671	GRET	SVC	2/4/2024	1992	RET ABN	UG-SERVICE
41143610	GRET	SVC	1/10/2023	1992	RET ABN	UG-SERVICE
41429207	GRET	SVC	3/22/2023	1992	RET ABN	UG-SERVICE
41177079	GRET	SVC	1/18/2023	1992	RET ABN	UG-SERVICE
40973551	GRET	SVC	12/5/2022	1992	RET ABN	UG-SERVICE
36878132	GRET	SVC	9/1/2020	1992	RET ABN	UG-SERVICE
41144495	GRET	SVC	1/12/2023	1992	RET ABN	UG-SERVICE
41568141	GRET	SVC	4/26/2023	1992	RET ABN	UG-SERVICE
42290060	GRET	SVC	10/30/2023	1992	RET ABN	UG-SERVICE
41429214	GRET	SVC	3/22/2023	1992	RET ABN	UG-SERVICE
40898338	GRET	SVC	11/10/2022	1992	RET ABN	UG-SERVICE
41143375	GRET	SVC	4/26/2023	1992	RET ABN	UG-SERVICE
41418435	GRET	SVC	3/21/2023	1992	RET ABN	UG-SERVICE
42905382	GRET	SVC	4/7/2024	1992	RET ABN	UG-SERVICE
41143373	GRET	SVC	1/12/2023	1992	RET ABN	UG-SERVICE
40899525	GRET	SVC	11/10/2022	1992	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40420603	GRET	SVC	6/27/2022	1992	RET ABN	UG-SERVICE
41317140	GRET	SVC	3/2/2023	1992	RET ABN	UG-SERVICE
40308199	GRET	SVC	6/13/2022	1992	RET ABN	UG-SERVICE
40772093	GRET	SVC	10/3/2022	1992	RET ABN	UG-SERVICE
40952953	GRET	SVC	11/18/2022	1992	RET ABN	UG-SERVICE
39070846	GRET	SVC	8/30/2021	1992	RET ABN	UG-SERVICE
41143735	GRET	SVC	7/31/2023	1992	RET ABN	UG-SERVICE
39832165	GRET	SVC	2/24/2022	1992	RET ABN	UG-SERVICE
41429212	GRET	SVC	3/22/2023	1992	RET ABN	UG-SERVICE
42773918	GRET	SVC	2/21/2024	1992	RET ABN	UG-SERVICE
41177539	GRET	SVC	1/20/2023	1992	RET ABN	UG-SERVICE
43481180	GRET	SVC	11/20/2024	1992	RET ABN	UG-SERVICE
42816107	GRET	SVC	3/11/2024	1992	RET ABN	UG-SERVICE
42626582	GRET	SVC	1/31/2024	1992	RET ABN	UG-SERVICE
40241954	GRET	SVC	5/21/2022	1992	RET ABN	UG-SERVICE
41330187	GRET	SVC	3/2/2023	1992	RET ABN	UG-SERVICE
40870056	GRET	SVC	11/9/2022	1992	RET ABN	UG-SERVICE
43481099	GRET	SVC	11/20/2024	1992	RET ABN	UG-SERVICE
35970017	GRET	SVC	2/3/2020	1992	RET ABN	UG-SERVICE
41143703	GRET	SVC	1/12/2023	1992	RET ABN	UG-SERVICE
43529740	GRET	SVC	12/13/2024	1992	RET ABN	UG-SERVICE
40683517	GRET	SVC	10/21/2022	1992	RET ABN	UG-SERVICE
42353320	GRET	SVC	11/13/2023	1992	RET ABN	UG-SERVICE
41904630	GRET	SVC	7/25/2023	1992	RET ABN	UG-SERVICE
42774030	GRET	SVC	2/21/2024	1992	RET ABN	UG-SERVICE
42015112	GRET	SVC	8/21/2023	1992	RET ABN	UG-SERVICE
40396046	GRET	SVC	7/6/2022	1992	RET ABN	UG-SERVICE
40813635	GRET	SVC	10/21/2022	1992	RET ABN	UG-SERVICE
38917203	GRET	SVC	8/13/2021	1992	RET ABN	UG-SERVICE
36609816	GRET	SVC	7/13/2020	1992	RET ABN	UG-SERVICE
39320982	GRET	SVC	10/19/2021	1992	RET ABN	UG-SERVICE
42479754	GRET	SVC	12/15/2023	1992	RET ABN	UG-SERVICE
38302240	GRET	SVC	5/26/2021	1992	RET ABN	UG-SERVICE
43108074	GRET	SVC	5/29/2024	1992	RET ABN	UG-SERVICE
42313855	GRET	SVC	10/31/2023	1992	RET ABN	UG-SERVICE
38276821	GRET	SVC	3/25/2021	1992	RET ABN	UG-SERVICE
42669945	GRET	SVC	2/3/2024	1992	RET ABN	UG-SERVICE
39876268	GRET	SVC	3/14/2022	1992	RET ABN	UG-SERVICE
41316946	GRET	SVC	3/2/2023	1992	RET ABN	UG-SERVICE
41334394	GRET	SVC	3/8/2023	1992	RET ABN	UG-SERVICE
41143633	GRET	SVC	7/31/2023	1992	RET ABN	UG-SERVICE
36888540	GRET	SVC	9/29/2020	1992	RET ABN	UG-SERVICE
36306734	GRET	SVC	5/7/2020	1992	RET ABN	UG-SERVICE
43481256	GRET	SVC	11/20/2024	1992	RET ABN	UG-SERVICE
41427192	GRET	SVC	3/23/2023	1992	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40898981	GRET	SVC	11/10/2022	1992	RET ABN	UG-SERVICE
39487066	GRET	SVC	12/20/2021	1992	RET ABN	UG-SERVICE
40973242	GRET	SVC	12/9/2022	1992	RET ABN	UG-SERVICE
42487565	GRET	SVC	4/23/2024	1992	RET ABN	UG-SERVICE
36218872	GRET	SVC	4/23/2020	1992	RET ABN	UG-SERVICE
42539236	GRET	SVC	12/27/2023	1992	RET ABN	UG-SERVICE
41177533	GRET	SVC	1/19/2023	1992	RET ABN	UG-SERVICE
40883298	GRET	SVC	10/30/2022	1992	RET ABN	UG-SERVICE
41144453	GRET	SVC	7/31/2023	1992	RET ABN	UG-SERVICE
41143729	GRET	SVC	4/25/2023	1992	RET ABN	UG-SERVICE
41422538	GRET	SVC	3/24/2023	1992	RET ABN	UG-SERVICE
40584964	GRET	SVC	8/19/2022	1992	RET ABN	UG-SERVICE
41428836	GRET	SVC	3/22/2023	1992	RET ABN	UG-SERVICE
43481181	GRET	SVC	11/20/2024	1992	RET ABN	UG-SERVICE
40396049	GRET	SVC	7/6/2022	1992	RET ABN	UG-SERVICE
41177525	GRET	SVC	1/19/2023	1992	RET ABN	UG-SERVICE
40694438	GRET	SVC	9/28/2022	1992	RET ABN	UG-SERVICE
40690733	GRET	SVC	9/14/2022	1992	RET ABN	UG-SERVICE
37032864	GRET	SVC	10/6/2020	1992	RET ABN	UG-SERVICE
40952583	GRET	SVC	11/17/2022	1992	RET ABN	UG-SERVICE
37887897	GRET	SVC	12/5/2020	1992	RET ABN	UG-SERVICE
43481097	GRET	SVC	11/20/2024	1992	RET ABN	UG-SERVICE
38862869	GRET	SVC	8/4/2021	1992	RET ABN	UG-SERVICE
43901346	GRET	SVC	12/13/2024	1992	RET ABN	UG-SERVICE
43414289	GRET	SVC	8/13/2024	1992	RET ABN	UG-SERVICE
41324891	GRET	SVC	3/1/2023	1992	RET ABN	UG-SERVICE
36089527	GRET	SVC	3/4/2020	1992	RET ABN	UG-SERVICE
41007068	GRET	SVC	12/9/2022	1992	RET ABN	UG-SERVICE
42409788	GRET	SVC	11/22/2023	1992	RET ABN	UG-SERVICE
43469644	GRET	SVC	8/23/2024	1992	RET ABN	UG-SERVICE
41411482	GRET	SVC	11/2/2023	1992	RET ABN	UG-SERVICE
41650006	GRET	SVC	5/14/2023	1992	RET ABN	UG-SERVICE
41177536	GRET	SVC	1/20/2023	1992	RET ABN	UG-SERVICE
39837492	GRET	SVC	2/28/2022	1992	RET ABN	UG-SERVICE
41245809	GRET	SVC	2/11/2023	1992	RET ABN	UG-SERVICE
42487444	GRET	SVC	4/15/2024	1992	RET ABN	UG-SERVICE
43347163	GRET	SVC	7/26/2024	1992	RET ABN	UG-SERVICE
41428834	GRET	SVC	3/22/2023	1992	RET ABN	UG-SERVICE
36199251	GRET	SVC	5/18/2020	1992	RET ABN	UG-SERVICE
40973553	GRET	SVC	12/9/2022	1992	RET ABN	UG-SERVICE
41258479	GRET	SVC	3/17/2023	1992	RET ABN	UG-SERVICE
40353366	GRET	SVC	6/27/2022	1992	RET ABN	UG-SERVICE
43607356	GRET	SVC	10/8/2024	1992	RET ABN	UG-SERVICE
40899522	GRET	SVC	11/10/2022	1992	RET ABN	UG-SERVICE
38052661	GRET	SVC	1/30/2021	1992	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41243171	GRET	SVC	2/5/2023	1992	RET ABN	UG-SERVICE
40916722	GRET	SVC	11/28/2022	1992	RET ABN	UG-SERVICE
43662628	GRET	SVC	10/9/2024	1992	RET ABN	UG-SERVICE
41177703	GRET	SVC	1/20/2023	1992	RET ABN	UG-SERVICE
38713758	GRET	SVC	7/20/2021	1992	RET ABN	UG-SERVICE
36712372	GRET	SVC	8/4/2020	1992	RET ABN	UG-SERVICE
42353480	GRET	SVC	11/13/2023	1992	RET ABN	UG-SERVICE
41144787	GRET	SVC	1/12/2023	1992	RET ABN	UG-SERVICE
38882775	GRET	SVC	8/10/2021	1992	RET ABN	UG-SERVICE
40466749	GRET	SVC	7/25/2022	1992	RET ABN	UG-SERVICE
43856858	GRET	SVC	11/20/2024	1992	RET ABN	UG-SERVICE
43244752	GRET	SVC	9/19/2024	1992	RET ABN	UG-SERVICE
39984699	GRET	SVC	10/14/2022	1993	RET ABN	UG-SERVICE
36380971	GRET	SVC	6/9/2020	1993	RET ABN	UG-SERVICE
43957767	GRET	SVC	12/10/2024	1993	RET ABN	UG-SERVICE
41031151	GRET	SVC	12/7/2022	1993	RET ABN	UG-SERVICE
36262294	GRET	SVC	4/27/2020	1993	RET ABN	UG-SERVICE
37863208	GRET	SVC	11/22/2020	1993	RET ABN	UG-SERVICE
38739429	GRET	SVC	7/12/2021	1993	RET ABN	UG-SERVICE
41497869	GRET	SVC	4/10/2023	1993	RET ABN	UG-SERVICE
42207700	GRET	SVC	10/9/2023	1993	RET ABN	UG-SERVICE
38857281	GRET	SVC	8/4/2021	1993	RET ABN	UG-SERVICE
37935104	GRET	SVC	12/20/2020	1993	RET ABN	UG-SERVICE
41407556	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
43327227	GRET	SVC	8/22/2024	1993	RET ABN	UG-SERVICE
39937838	GRET	SVC	2/14/2022	1993	RET ABN	UG-SERVICE
41179724	GRET	SVC	1/18/2023	1993	RET ABN	UG-SERVICE
40913278	GRET	SVC	11/16/2022	1993	RET ABN	UG-SERVICE
40643028	GRET	SVC	9/2/2022	1993	RET ABN	UG-SERVICE
43241683	GRET	SVC	9/19/2024	1993	RET ABN	UG-SERVICE
43205832	GRET	SVC	6/17/2024	1993	RET ABN	UG-SERVICE
40352156	GRET	SVC	6/27/2022	1993	RET ABN	UG-SERVICE
41035751	GRET	SVC	12/13/2022	1993	RET ABN	UG-SERVICE
42111992	GRET	SVC	9/14/2023	1993	RET ABN	UG-SERVICE
43480989	GRET	SVC	11/8/2024	1993	RET ABN	UG-SERVICE
42344241	GRET	SVC	11/12/2023	1993	RET ABN	UG-SERVICE
36778382	GRET	SVC	8/13/2020	1993	RET ABN	UG-SERVICE
41411585	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
39984698	GRET	SVC	5/2/2022	1993	RET ABN	UG-SERVICE
41146290	GRET	SVC	1/9/2023	1993	RET ABN	UG-SERVICE
43506820	GRET	SVC	9/25/2024	1993	RET ABN	UG-SERVICE
40900096	GRET	SVC	11/7/2022	1993	RET ABN	UG-SERVICE
38493263	GRET	SVC	5/18/2021	1993	RET ABN	UG-SERVICE
39903271	GRET	SVC	3/18/2022	1993	RET ABN	UG-SERVICE
38191772	GRET	SVC	3/8/2021	1993	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42205741	GRET	SVC	10/13/2023	1993	RET ABN	UG-SERVICE
36837125	GRET	SVC	8/27/2020	1993	RET ABN	UG-SERVICE
43026498	GRET	SVC	5/8/2024	1993	RET ABN	UG-SERVICE
38779477	GRET	SVC	7/15/2021	1993	RET ABN	UG-SERVICE
39665676	GRET	SVC	8/3/2022	1993	RET ABN	UG-SERVICE
40952498	GRET	SVC	11/20/2022	1993	RET ABN	UG-SERVICE
41427198	GRET	SVC	3/23/2023	1993	RET ABN	UG-SERVICE
41411596	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
36427762	GRET	SVC	6/6/2020	1993	RET ABN	UG-SERVICE
38040119	GRET	SVC	5/4/2021	1993	RET ABN	UG-SERVICE
40989593	GRET	SVC	11/17/2022	1993	RET ABN	UG-SERVICE
41185240	GRET	SVC	1/19/2023	1993	RET ABN	UG-SERVICE
42227547	GRET	SVC	10/31/2023	1993	RET ABN	UG-SERVICE
43241279	GRET	SVC	9/19/2024	1993	RET ABN	UG-SERVICE
41411655	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
40425799	GRET	SVC	7/13/2022	1993	RET ABN	UG-SERVICE
40749752	GRET	SVC	9/29/2022	1993	RET ABN	UG-SERVICE
40883287	GRET	SVC	10/30/2022	1993	RET ABN	UG-SERVICE
37896727	GRET	SVC	12/9/2020	1993	RET ABN	UG-SERVICE
38376930	GRET	SVC	1/22/2021	1993	RET ABN	UG-SERVICE
41770798	GRET	SVC	6/23/2023	1993	RET ABN	UG-SERVICE
43982688	GRET	SVC	12/12/2024	1993	RET ABN	UG-SERVICE
41497865	GRET	SVC	4/6/2023	1993	RET ABN	UG-SERVICE
36152589	GRET	SVC	3/24/2020	1993	RET ABN	UG-SERVICE
41420312	GRET	SVC	3/23/2023	1993	RET ABN	UG-SERVICE
41320579	GRET	SVC	3/3/2023	1993	RET ABN	UG-SERVICE
38568738	GRET	SVC	6/9/2021	1993	RET ABN	UG-SERVICE
39098295	GRET	SVC	9/8/2021	1993	RET ABN	UG-SERVICE
43957768	GRET	SVC	12/9/2024	1993	RET ABN	UG-SERVICE
41497626	GRET	SVC	4/17/2023	1993	RET ABN	UG-SERVICE
41035836	GRET	SVC	12/3/2022	1993	RET ABN	UG-SERVICE
36984588	GRET	SVC	9/21/2020	1993	RET ABN	UG-SERVICE
41401756	GRET	SVC	3/15/2023	1993	RET ABN	UG-SERVICE
38153161	GRET	SVC	2/23/2021	1993	RET ABN	UG-SERVICE
36992556	GRET	SVC	9/30/2020	1993	RET ABN	UG-SERVICE
42586960	GRET	SVC	1/12/2024	1993	RET ABN	UG-SERVICE
40644077	GRET	SVC	9/3/2022	1993	RET ABN	UG-SERVICE
36002277	GRET	SVC	2/8/2020	1993	RET ABN	UG-SERVICE
42589413	GRET	SVC	1/26/2024	1993	RET ABN	UG-SERVICE
38783978	GRET	SVC	7/15/2021	1993	RET ABN	UG-SERVICE
42048234	GRET	SVC	8/30/2023	1993	RET ABN	UG-SERVICE
40952485	GRET	SVC	11/20/2022	1993	RET ABN	UG-SERVICE
42259859	GRET	SVC	11/6/2023	1993	RET ABN	UG-SERVICE
40748422	GRET	SVC	10/4/2022	1993	RET ABN	UG-SERVICE
39484906	GRET	SVC	11/29/2021	1993	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41035832	GRET	SVC	12/8/2022	1993	RET ABN	UG-SERVICE
43021641	GRET	SVC	4/22/2024	1993	RET ABN	UG-SERVICE
43481182	GRET	SVC	11/20/2024	1993	RET ABN	UG-SERVICE
43623426	GRET	SVC	12/6/2024	1993	RET ABN	UG-SERVICE
39266989	GRET	SVC	10/4/2021	1993	RET ABN	UG-SERVICE
39184089	GRET	SVC	9/22/2021	1993	RET ABN	UG-SERVICE
41411593	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
43957764	GRET	SVC	12/19/2024	1993	RET ABN	UG-SERVICE
43957763	GRET	SVC	12/11/2024	1993	RET ABN	UG-SERVICE
39739691	GRET	SVC	2/10/2022	1993	RET ABN	UG-SERVICE
41082585	GRET	SVC	12/21/2022	1993	RET ABN	UG-SERVICE
39786419	GRET	SVC	2/21/2022	1993	RET ABN	UG-SERVICE
38133227	GRET	SVC	2/15/2021	1993	RET ABN	UG-SERVICE
43241680	GRET	SVC	9/19/2024	1993	RET ABN	UG-SERVICE
39352989	GRET	SVC	10/28/2021	1993	RET ABN	UG-SERVICE
42344678	GRET	SVC	11/6/2023	1993	RET ABN	UG-SERVICE
36882130	GRET	SVC	9/1/2020	1993	RET ABN	UG-SERVICE
41768365	GRET	SVC	6/23/2023	1993	RET ABN	UG-SERVICE
42170232	GRET	SVC	10/16/2023	1993	RET ABN	UG-SERVICE
41016209	GRET	SVC	12/12/2022	1993	RET ABN	UG-SERVICE
40514003	GRET	SVC	8/2/2022	1993	RET ABN	UG-SERVICE
42511205	GRET	SVC	4/15/2024	1993	RET ABN	UG-SERVICE
40370774	GRET	SVC	7/6/2022	1993	RET ABN	UG-SERVICE
39254599	GRET	SVC	10/5/2021	1993	RET ABN	UG-SERVICE
41411589	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
40327786	GRET	SVC	9/30/2022	1993	RET ABN	UG-SERVICE
42426287	GRET	SVC	11/28/2023	1993	RET ABN	UG-SERVICE
36397063	GRET	SVC	6/4/2020	1993	RET ABN	UG-SERVICE
43241682	GRET	SVC	9/19/2024	1993	RET ABN	UG-SERVICE
36826472	GRET	SVC	8/24/2020	1993	RET ABN	UG-SERVICE
40952329	GRET	SVC	11/18/2022	1993	RET ABN	UG-SERVICE
38153564	GRET	SVC	2/10/2021	1993	RET ABN	UG-SERVICE
35924715	GRET	SVC	1/16/2020	1993	RET ABN	UG-SERVICE
43957760	GRET	SVC	12/9/2024	1993	RET ABN	UG-SERVICE
41083459	GRET	SVC	1/7/2023	1993	RET ABN	UG-SERVICE
40883591	GRET	SVC	11/8/2022	1993	RET ABN	UG-SERVICE
38793267	GRET	SVC	7/22/2021	1993	RET ABN	UG-SERVICE
42589550	GRET	SVC	1/26/2024	1993	RET ABN	UG-SERVICE
41006861	GRET	SVC	12/7/2022	1993	RET ABN	UG-SERVICE
39903766	GRET	SVC	3/18/2022	1993	RET ABN	UG-SERVICE
39906731	GRET	SVC	6/3/2022	1993	RET ABN	UG-SERVICE
41411954	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
39825103	GRET	SVC	2/22/2022	1993	RET ABN	UG-SERVICE
39302358	GRET	SVC	10/18/2021	1993	RET ABN	UG-SERVICE
43498333	GRET	SVC	8/26/2024	1993	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
37528691	GRET	SVC	11/18/2020	1993	RET ABN	UG-SERVICE
38779079	GRET	SVC	7/15/2021	1993	RET ABN	UG-SERVICE
39838385	GRET	SVC	2/21/2022	1993	RET ABN	UG-SERVICE
42116060	GRET	SVC	9/15/2023	1993	RET ABN	UG-SERVICE
37059285	GRET	SVC	10/28/2020	1993	RET ABN	UG-SERVICE
39306786	GRET	SVC	10/25/2021	1993	RET ABN	UG-SERVICE
38817197	GRET	SVC	7/21/2021	1993	RET ABN	UG-SERVICE
41872475	GRET	SVC	7/12/2023	1993	RET ABN	UG-SERVICE
43481246	GRET	SVC	9/28/2024	1993	RET ABN	UG-SERVICE
43481255	GRET	SVC	11/20/2024	1993	RET ABN	UG-SERVICE
36868129	GRET	SVC	8/29/2020	1993	RET ABN	UG-SERVICE
39691376	GRET	SVC	1/18/2022	1993	RET ABN	UG-SERVICE
39060316	GRET	SVC	9/16/2021	1993	RET ABN	UG-SERVICE
40153194	GRET	SVC	5/10/2022	1993	RET ABN	UG-SERVICE
41411653	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
42517560	GRET	SVC	12/27/2023	1993	RET ABN	UG-SERVICE
41584965	GRET	SVC	5/1/2023	1993	RET ABN	UG-SERVICE
43241684	GRET	SVC	9/19/2024	1993	RET ABN	UG-SERVICE
36436503	GRET	SVC	6/6/2020	1993	RET ABN	UG-SERVICE
39895906	GRET	SVC	3/16/2022	1993	RET ABN	UG-SERVICE
38851993	GRET	SVC	11/2/2021	1993	RET ABN	UG-SERVICE
38207650	GRET	SVC	3/15/2021	1993	RET ABN	UG-SERVICE
42208707	GRET	SVC	10/10/2023	1993	RET ABN	UG-SERVICE
41573436	GRET	SVC	5/1/2023	1993	RET ABN	UG-SERVICE
43957762	GRET	SVC	12/11/2024	1993	RET ABN	UG-SERVICE
36769541	GRET	SVC	7/4/2020	1993	RET ABN	UG-SERVICE
42956492	GRET	SVC	4/20/2024	1993	RET ABN	UG-SERVICE
43318026	GRET	SVC	7/29/2024	1993	RET ABN	UG-SERVICE
42336298	GRET	SVC	4/16/2024	1993	RET ABN	UG-SERVICE
36709888	GRET	SVC	8/4/2020	1993	RET ABN	UG-SERVICE
40395344	GRET	SVC	7/5/2022	1993	RET ABN	UG-SERVICE
42245667	GRET	SVC	10/4/2023	1993	RET ABN	UG-SERVICE
40595240	GRET	SVC	8/14/2022	1993	RET ABN	UG-SERVICE
41411919	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
39785597	GRET	SVC	2/21/2022	1993	RET ABN	UG-SERVICE
41036020	GRET	SVC	12/7/2022	1993	RET ABN	UG-SERVICE
43957765	GRET	SVC	12/19/2024	1993	RET ABN	UG-SERVICE
39191278	GRET	SVC	9/24/2021	1993	RET ABN	UG-SERVICE
43506884	GRET	SVC	9/25/2024	1993	RET ABN	UG-SERVICE
38632600	GRET	SVC	6/14/2021	1993	RET ABN	UG-SERVICE
39177676	GRET	SVC	9/21/2021	1993	RET ABN	UG-SERVICE
41390581	GRET	SVC	3/17/2023	1993	RET ABN	UG-SERVICE
41677520	GRET	SVC	5/30/2023	1993	RET ABN	UG-SERVICE
43250695	GRET	SVC	12/26/2024	1993	RET ABN	UG-SERVICE
36793069	GRET	SVC	8/18/2020	1993	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41497335	GRET	SVC	4/6/2023	1993	RET ABN	UG-SERVICE
38441439	GRET	SVC	1/6/2022	1993	RET ABN	UG-SERVICE
36886591	GRET	SVC	7/7/2021	1993	RET ABN	UG-SERVICE
42588548	GRET	SVC	1/31/2024	1993	RET ABN	UG-SERVICE
42317372	GRET	SVC	10/24/2023	1993	RET ABN	UG-SERVICE
43241688	GRET	SVC	9/19/2024	1993	RET ABN	UG-SERVICE
41088874	GRET	SVC	12/22/2022	1993	RET ABN	UG-SERVICE
41411587	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
43978376	GRET	SVC	12/23/2024	1993	RET ABN	UG-SERVICE
39552702	GRET	SVC	12/17/2021	1993	RET ABN	UG-SERVICE
41184946	GRET	SVC	1/19/2023	1993	RET ABN	UG-SERVICE
41411595	GRET	SVC	4/2/2024	1993	RET ABN	UG-SERVICE
40277457	GRET	SVC	4/27/2023	1993	RET ABN	UG-SERVICE
41101692	GRET	SVC	1/30/2023	1993	RET ABN	UG-SERVICE
43241278	GRET	SVC	9/17/2024	1993	RET ABN	UG-SERVICE
43957769	GRET	SVC	12/9/2024	1993	RET ABN	UG-SERVICE
41727358	GRET	SVC	6/16/2023	1993	RET ABN	UG-SERVICE
41187076	GRET	SVC	1/18/2023	1993	RET ABN	UG-SERVICE
41083458	GRET	SVC	1/4/2023	1993	RET ABN	UG-SERVICE
42201247	GRET	SVC	10/9/2023	1993	RET ABN	UG-SERVICE
37924849	GRET	SVC	12/16/2020	1993	RET ABN	UG-SERVICE
35868779	GRET	SVC	2/11/2020	1993	RET ABN	UG-SERVICE
37934852	GRET	SVC	12/19/2020	1993	RET ABN	UG-SERVICE
39984017	GRET	SVC	6/9/2022	1993	RET ABN	UG-SERVICE
41928924	GRET	SVC	7/19/2023	1993	RET ABN	UG-SERVICE
42156958	GRET	SVC	9/27/2023	1993	RET ABN	UG-SERVICE
41507925	GRET	SVC	4/13/2023	1993	RET ABN	UG-SERVICE
37048150	GRET	SVC	10/5/2020	1993	RET ABN	UG-SERVICE
36710983	GRET	SVC	8/3/2020	1993	RET ABN	UG-SERVICE
40558161	GRET	SVC	8/12/2022	1993	RET ABN	UG-SERVICE
40813750	GRET	SVC	10/17/2022	1993	RET ABN	UG-SERVICE
39890620	GRET	SVC	3/14/2022	1993	RET ABN	UG-SERVICE
42442496	GRET	SVC	12/2/2023	1993	RET ABN	UG-SERVICE
41392507	GRET	SVC	3/26/2023	1993	RET ABN	UG-SERVICE
43957771	GRET	SVC	12/9/2024	1993	RET ABN	UG-SERVICE
42505488	GRET	SVC	12/26/2023	1993	RET ABN	UG-SERVICE
38779467	GRET	SVC	7/15/2021	1993	RET ABN	UG-SERVICE
41933546	GRET	SVC	10/13/2023	1993	RET ABN	UG-SERVICE
40199012	GRET	SVC	5/31/2022	1993	RET ABN	UG-SERVICE
43191348	GRET	SVC	6/25/2024	1993	RET ABN	UG-SERVICE
40732875	GRET	SVC	10/1/2022	1993	RET ABN	UG-SERVICE
36221953	GRET	SVC	4/23/2020	1993	RET ABN	UG-SERVICE
42658316	GRET	SVC	2/5/2024	1993	RET ABN	UG-SERVICE
40318182	GRET	SVC	6/17/2022	1993	RET ABN	UG-SERVICE
43498111	GRET	SVC	8/26/2024	1993	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
37098566	GRET	SVC	10/29/2020	1993	RET ABN	UG-SERVICE
42137945	GRET	SVC	9/22/2023	1993	RET ABN	UG-SERVICE
41083721	GRET	SVC	12/21/2022	1993	RET ABN	UG-SERVICE
41813702	GRET	SVC	6/29/2023	1994	RET ABN	UG-SERVICE
40943969	GRET	SVC	11/28/2022	1994	RET ABN	UG-SERVICE
43492538	GRET	SVC	12/3/2024	1994	RET ABN	UG-SERVICE
40395859	GRET	SVC	7/6/2022	1994	RET ABN	UG-SERVICE
41099795	GRET	SVC	1/5/2023	1994	RET ABN	UG-SERVICE
43951150	GRET	SVC	12/17/2024	1994	RET ABN	UG-SERVICE
38783975	GRET	SVC	7/13/2021	1994	RET ABN	UG-SERVICE
43529376	GRET	SVC	10/27/2024	1994	RET ABN	UG-SERVICE
43529753	GRET	SVC	12/22/2024	1994	RET ABN	UG-SERVICE
42322524	GRET	SVC	4/2/2024	1994	RET ABN	UG-SERVICE
41877018	GRET	SVC	7/18/2023	1994	RET ABN	UG-SERVICE
39681495	GRET	SVC	1/14/2022	1994	RET ABN	UG-SERVICE
38900666	GRET	SVC	10/12/2021	1994	RET ABN	UG-SERVICE
39753654	GRET	SVC	1/26/2022	1994	RET ABN	UG-SERVICE
40987271	GRET	SVC	11/30/2022	1994	RET ABN	UG-SERVICE
36177525	GRET	SVC	2/14/2020	1994	RET ABN	UG-SERVICE
36470402	GRET	SVC	6/22/2020	1994	RET ABN	UG-SERVICE
41426054	GRET	SVC	3/24/2023	1994	RET ABN	UG-SERVICE
42344007	GRET	SVC	4/2/2024	1994	RET ABN	UG-SERVICE
39854795	GRET	SVC	3/9/2022	1994	RET ABN	UG-SERVICE
37929078	GRET	SVC	12/16/2020	1994	RET ABN	UG-SERVICE
37120664	GRET	SVC	10/24/2020	1994	RET ABN	UG-SERVICE
42418511	GRET	SVC	10/14/2023	1994	RET ABN	UG-SERVICE
43020926	GRET	SVC	5/24/2024	1994	RET ABN	UG-SERVICE
38875200	GRET	SVC	8/4/2021	1994	RET ABN	UG-SERVICE
43135174	GRET	SVC	6/4/2024	1994	RET ABN	UG-SERVICE
41411424	GRET	SVC	11/2/2023	1994	RET ABN	UG-SERVICE
41244977	GRET	SVC	2/6/2023	1994	RET ABN	UG-SERVICE
41195734	GRET	SVC	1/24/2023	1994	RET ABN	UG-SERVICE
37987403	GRET	SVC	1/5/2021	1994	RET ABN	UG-SERVICE
38499745	GRET	SVC	5/18/2021	1994	RET ABN	UG-SERVICE
43909723	GRET	SVC	12/6/2024	1994	RET ABN	UG-SERVICE
43365780	GRET	SVC	12/3/2024	1994	RET ABN	UG-SERVICE
43529730	GRET	SVC	11/27/2024	1994	RET ABN	UG-SERVICE
41288879	GRET	SVC	3/17/2023	1994	RET ABN	UG-SERVICE
41207591	GRET	SVC	1/24/2023	1994	RET ABN	UG-SERVICE
37120663	GRET	SVC	10/24/2020	1994	RET ABN	UG-SERVICE
42825292	GRET	SVC	3/11/2024	1994	RET ABN	UG-SERVICE
43529378	GRET	SVC	11/2/2024	1994	RET ABN	UG-SERVICE
41185660	GRET	SVC	1/26/2023	1994	RET ABN	UG-SERVICE
43623435	GRET	SVC	12/2/2024	1994	RET ABN	UG-SERVICE
41288866	GRET	SVC	3/17/2023	1994	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40723313	GRET	SVC	10/7/2022	1994	RET ABN	UG-SERVICE
36998791	GRET	SVC	9/28/2020	1994	RET ABN	UG-SERVICE
40864102	GRET	SVC	10/31/2022	1994	RET ABN	UG-SERVICE
41552451	GRET	SVC	4/28/2023	1994	RET ABN	UG-SERVICE
36576775	GRET	SVC	8/6/2020	1994	RET ABN	UG-SERVICE
39390797	GRET	SVC	11/19/2021	1994	RET ABN	UG-SERVICE
38779469	GRET	SVC	7/13/2021	1994	RET ABN	UG-SERVICE
40116597	GRET	SVC	5/6/2022	1994	RET ABN	UG-SERVICE
38189719	GRET	SVC	3/15/2021	1994	RET ABN	UG-SERVICE
42506402	GRET	SVC	12/28/2023	1994	RET ABN	UG-SERVICE
41211396	GRET	SVC	1/30/2023	1994	RET ABN	UG-SERVICE
41649933	GRET	SVC	5/16/2023	1994	RET ABN	UG-SERVICE
39721214	GRET	SVC	1/25/2022	1994	RET ABN	UG-SERVICE
40222490	GRET	SVC	5/31/2022	1994	RET ABN	UG-SERVICE
41085376	GRET	SVC	1/4/2023	1994	RET ABN	UG-SERVICE
36605914	GRET	SVC	7/9/2020	1994	RET ABN	UG-SERVICE
39455877	GRET	SVC	11/22/2021	1994	RET ABN	UG-SERVICE
40318192	GRET	SVC	6/17/2022	1994	RET ABN	UG-SERVICE
38146654	GRET	SVC	2/17/2021	1994	RET ABN	UG-SERVICE
38095982	GRET	SVC	2/15/2021	1994	RET ABN	UG-SERVICE
36485802	GRET	SVC	6/20/2020	1994	RET ABN	UG-SERVICE
43617825	GRET	SVC	9/24/2024	1994	RET ABN	UG-SERVICE
36707376	GRET	SVC	7/21/2020	1994	RET ABN	UG-SERVICE
36142355	GRET	SVC	3/17/2020	1994	RET ABN	UG-SERVICE
41427447	GRET	SVC	3/21/2023	1994	RET ABN	UG-SERVICE
43042233	GRET	SVC	5/14/2024	1994	RET ABN	UG-SERVICE
42705990	GRET	SVC	2/14/2024	1994	RET ABN	UG-SERVICE
42855625	GRET	SVC	3/26/2024	1994	RET ABN	UG-SERVICE
43529726	GRET	SVC	11/27/2024	1994	RET ABN	UG-SERVICE
41139009	GRET	SVC	1/21/2023	1994	RET ABN	UG-SERVICE
43529731	GRET	SVC	11/2/2024	1994	RET ABN	UG-SERVICE
43300973	GRET	SVC	7/13/2024	1994	RET ABN	UG-SERVICE
39224492	GRET	SVC	9/30/2021	1994	RET ABN	UG-SERVICE
41317489	GRET	SVC	3/3/2023	1994	RET ABN	UG-SERVICE
39966172	GRET	SVC	2/22/2022	1994	RET ABN	UG-SERVICE
39299440	GRET	SVC	10/18/2021	1994	RET ABN	UG-SERVICE
43323975	GRET	SVC	7/24/2024	1994	RET ABN	UG-SERVICE
43731861	GRET	SVC	10/21/2024	1994	RET ABN	UG-SERVICE
36505784	GRET	SVC	6/23/2020	1994	RET ABN	UG-SERVICE
41123319	GRET	SVC	1/4/2023	1994	RET ABN	UG-SERVICE
41057669	GRET	SVC	12/14/2022	1994	RET ABN	UG-SERVICE
39630749	GRET	SVC	1/4/2022	1994	RET ABN	UG-SERVICE
39333382	GRET	SVC	11/2/2021	1994	RET ABN	UG-SERVICE
40973116	GRET	SVC	11/18/2022	1994	RET ABN	UG-SERVICE
43529744	GRET	SVC	12/6/2024	1994	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39666486	GRET	SVC	11/18/2022	1994	RET ABN	UG-SERVICE
43493327	GRET	SVC	10/22/2024	1994	RET ABN	UG-SERVICE
43826770	GRET	SVC	11/12/2024	1994	RET ABN	UG-SERVICE
43529728	GRET	SVC	10/27/2024	1994	RET ABN	UG-SERVICE
39277584	GRET	SVC	10/11/2021	1994	RET ABN	UG-SERVICE
42135700	GRET	SVC	9/20/2023	1994	RET ABN	UG-SERVICE
42113245	GRET	SVC	9/11/2023	1994	RET ABN	UG-SERVICE
38298837	GRET	SVC	3/25/2021	1994	RET ABN	UG-SERVICE
41425309	GRET	SVC	3/21/2023	1994	RET ABN	UG-SERVICE
37525595	GRET	SVC	11/16/2020	1994	RET ABN	UG-SERVICE
39070007	GRET	SVC	8/30/2021	1994	RET ABN	UG-SERVICE
43507270	GRET	SVC	9/9/2024	1994	RET ABN	UG-SERVICE
37082844	GRET	SVC	10/16/2020	1994	RET ABN	UG-SERVICE
43529751	GRET	SVC	12/13/2024	1994	RET ABN	UG-SERVICE
39666491	GRET	SVC	11/18/2022	1994	RET ABN	UG-SERVICE
40239927	GRET	SVC	5/28/2022	1994	RET ABN	UG-SERVICE
43529752	GRET	SVC	12/21/2024	1994	RET ABN	UG-SERVICE
38458599	GRET	SVC	5/5/2021	1994	RET ABN	UG-SERVICE
41277358	GRET	SVC	2/14/2023	1994	RET ABN	UG-SERVICE
42159014	GRET	SVC	9/22/2023	1994	RET ABN	UG-SERVICE
43529379	GRET	SVC	11/24/2024	1994	RET ABN	UG-SERVICE
40456748	GRET	SVC	7/18/2022	1994	RET ABN	UG-SERVICE
40498173	GRET	SVC	7/27/2022	1994	RET ABN	UG-SERVICE
43529720	GRET	SVC	11/24/2024	1994	RET ABN	UG-SERVICE
39398834	GRET	SVC	11/8/2021	1994	RET ABN	UG-SERVICE
41113796	GRET	SVC	12/28/2022	1994	RET ABN	UG-SERVICE
36009496	GRET	SVC	2/10/2020	1994	RET ABN	UG-SERVICE
40396838	GRET	SVC	7/11/2022	1994	RET ABN	UG-SERVICE
39992844	GRET	SVC	4/11/2022	1994	RET ABN	UG-SERVICE
41770913	GRET	SVC	8/7/2023	1994	RET ABN	UG-SERVICE
37020751	GRET	SVC	10/10/2020	1994	RET ABN	UG-SERVICE
36633102	GRET	SVC	7/14/2020	1994	RET ABN	UG-SERVICE
42695250	GRET	SVC	2/10/2024	1994	RET ABN	UG-SERVICE
36724026	GRET	SVC	8/4/2020	1994	RET ABN	UG-SERVICE
39744802	GRET	SVC	2/8/2022	1994	RET ABN	UG-SERVICE
38002843	GRET	SVC	1/11/2021	1994	RET ABN	UG-SERVICE
36576604	GRET	SVC	8/6/2020	1994	RET ABN	UG-SERVICE
41286923	GRET	SVC	2/15/2023	1994	RET ABN	UG-SERVICE
40847366	GRET	SVC	11/20/2022	1994	RET ABN	UG-SERVICE
38454097	GRET	SVC	5/7/2021	1994	RET ABN	UG-SERVICE
36120513	GRET	SVC	3/13/2020	1994	RET ABN	UG-SERVICE
36980371	GRET	SVC	9/21/2020	1994	RET ABN	UG-SERVICE
36791124	GRET	SVC	9/4/2020	1994	RET ABN	UG-SERVICE
43529725	GRET	SVC	11/27/2024	1994	RET ABN	UG-SERVICE
40561703	GRET	SVC	8/17/2022	1994	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43251087	GRET	SVC	6/24/2024	1994	RET ABN	UG-SERVICE
39820706	GRET	SVC	2/22/2022	1994	RET ABN	UG-SERVICE
40655356	GRET	SVC	10/21/2022	1994	RET ABN	UG-SERVICE
41428827	GRET	SVC	3/23/2023	1995	RET ABN	UG-SERVICE
42654196	GRET	SVC	2/2/2024	1995	RET ABN	UG-SERVICE
37070438	GRET	SVC	8/19/2020	1995	RET ABN	UG-SERVICE
42817716	GRET	SVC	4/17/2024	1995	RET ABN	UG-SERVICE
42419488	GRET	SVC	11/27/2023	1995	RET ABN	UG-SERVICE
41015454	GRET	SVC	12/16/2022	1995	RET ABN	UG-SERVICE
36672044	GRET	SVC	8/7/2020	1995	RET ABN	UG-SERVICE
41242177	GRET	SVC	3/1/2023	1995	RET ABN	UG-SERVICE
41760937	GRET	SVC	8/2/2023	1995	RET ABN	UG-SERVICE
40048048	GRET	SVC	4/22/2022	1995	RET ABN	UG-SERVICE
43705926	GRET	SVC	10/14/2024	1995	RET ABN	UG-SERVICE
43150812	GRET	SVC	6/6/2024	1995	RET ABN	UG-SERVICE
43245087	GRET	SVC	9/11/2024	1995	RET ABN	UG-SERVICE
42834263	GRET	SVC	7/23/2024	1995	RET ABN	UG-SERVICE
39903275	GRET	SVC	3/15/2022	1995	RET ABN	UG-SERVICE
41429218	GRET	SVC	3/24/2023	1995	RET ABN	UG-SERVICE
40749609	GRET	SVC	9/29/2022	1995	RET ABN	UG-SERVICE
36301953	GRET	SVC	5/13/2020	1995	RET ABN	UG-SERVICE
40870524	GRET	SVC	11/9/2022	1995	RET ABN	UG-SERVICE
41951085	GRET	SVC	8/4/2023	1995	RET ABN	UG-SERVICE
40551322	GRET	SVC	8/16/2022	1995	RET ABN	UG-SERVICE
41402081	GRET	SVC	3/15/2023	1995	RET ABN	UG-SERVICE
40396055	GRET	SVC	7/6/2022	1995	RET ABN	UG-SERVICE
40855837	GRET	SVC	10/22/2022	1995	RET ABN	UG-SERVICE
41244979	GRET	SVC	2/4/2023	1995	RET ABN	UG-SERVICE
42695047	GRET	SVC	2/14/2024	1995	RET ABN	UG-SERVICE
38521182	GRET	SVC	6/4/2021	1995	RET ABN	UG-SERVICE
36946066	GRET	SVC	9/15/2020	1995	RET ABN	UG-SERVICE
41375577	GRET	SVC	3/13/2023	1995	RET ABN	UG-SERVICE
40461409	GRET	SVC	7/21/2022	1995	RET ABN	UG-SERVICE
37490029	GRET	SVC	12/11/2020	1995	RET ABN	UG-SERVICE
39646756	GRET	SVC	4/11/2022	1995	RET ABN	UG-SERVICE
36399235	GRET	SVC	6/1/2020	1995	RET ABN	UG-SERVICE
40952499	GRET	SVC	11/19/2022	1995	RET ABN	UG-SERVICE
41279174	GRET	SVC	2/24/2023	1995	RET ABN	UG-SERVICE
43323976	GRET	SVC	7/25/2024	1995	RET ABN	UG-SERVICE
35959607	GRET	SVC	1/28/2020	1995	RET ABN	UG-SERVICE
39494528	GRET	SVC	12/14/2021	1995	RET ABN	UG-SERVICE
40174364	GRET	SVC	6/6/2022	1995	RET ABN	UG-SERVICE
40201045	GRET	SVC	6/6/2022	1995	RET ABN	UG-SERVICE
40661475	GRET	SVC	9/22/2022	1995	RET ABN	UG-SERVICE
41708455	GRET	SVC	6/5/2023	1995	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40013196	GRET	SVC	4/19/2022	1995	RET ABN	UG-SERVICE
43481122	GRET	SVC	10/28/2024	1995	RET ABN	UG-SERVICE
42611333	GRET	SVC	1/24/2024	1995	RET ABN	UG-SERVICE
39581789	GRET	SVC	12/26/2021	1995	RET ABN	UG-SERVICE
39554828	GRET	SVC	12/28/2021	1995	RET ABN	UG-SERVICE
41242172	GRET	SVC	3/2/2023	1995	RET ABN	UG-SERVICE
43862404	GRET	SVC	11/22/2024	1995	RET ABN	UG-SERVICE
42534910	GRET	SVC	1/4/2024	1995	RET ABN	UG-SERVICE
41332048	GRET	SVC	3/1/2023	1995	RET ABN	UG-SERVICE
41428823	GRET	SVC	3/27/2023	1995	RET ABN	UG-SERVICE
41513273	GRET	SVC	4/16/2023	1995	RET ABN	UG-SERVICE
38713913	GRET	SVC	7/7/2021	1995	RET ABN	UG-SERVICE
43535155	GRET	SVC	9/30/2024	1995	RET ABN	UG-SERVICE
42276448	GRET	SVC	10/26/2023	1995	RET ABN	UG-SERVICE
41223589	GRET	SVC	2/3/2023	1995	RET ABN	UG-SERVICE
41969540	GRET	SVC	8/1/2024	1995	RET ABN	UG-SERVICE
40951421	GRET	SVC	1/5/2023	1995	RET ABN	UG-SERVICE
41834504	GRET	SVC	7/21/2023	1995	RET ABN	UG-SERVICE
40841472	GRET	SVC	10/20/2022	1995	RET ABN	UG-SERVICE
41418707	GRET	SVC	3/22/2023	1995	RET ABN	UG-SERVICE
41175947	GRET	SVC	1/17/2023	1995	RET ABN	UG-SERVICE
42336324	GRET	SVC	4/16/2024	1995	RET ABN	UG-SERVICE
40913346	GRET	SVC	11/7/2022	1995	RET ABN	UG-SERVICE
36101932	GRET	SVC	2/8/2020	1995	RET ABN	UG-SERVICE
38109797	GRET	SVC	12/29/2020	1995	RET ABN	UG-SERVICE
38122800	GRET	SVC	2/10/2021	1995	RET ABN	UG-SERVICE
40862490	GRET	SVC	10/28/2022	1995	RET ABN	UG-SERVICE
40506086	GRET	SVC	8/2/2022	1995	RET ABN	UG-SERVICE
42959506	GRET	SVC	4/22/2024	1995	RET ABN	UG-SERVICE
42336327	GRET	SVC	4/19/2024	1995	RET ABN	UG-SERVICE
37143043	GRET	SVC	11/13/2020	1995	RET ABN	UG-SERVICE
36829570	GRET	SVC	8/27/2020	1995	RET ABN	UG-SERVICE
43633875	GRET	SVC	10/16/2024	1995	RET ABN	UG-SERVICE
43410047	GRET	SVC	8/28/2024	1995	RET ABN	UG-SERVICE
42560751	GRET	SVC	1/9/2024	1995	RET ABN	UG-SERVICE
39368598	GRET	SVC	11/2/2021	1995	RET ABN	UG-SERVICE
38567222	GRET	SVC	6/1/2021	1995	RET ABN	UG-SERVICE
41423930	GRET	SVC	3/22/2023	1995	RET ABN	UG-SERVICE
41015754	GRET	SVC	12/14/2022	1995	RET ABN	UG-SERVICE
41545676	GRET	SVC	4/23/2023	1995	RET ABN	UG-SERVICE
42226971	GRET	SVC	10/12/2023	1995	RET ABN	UG-SERVICE
42706083	GRET	SVC	2/6/2024	1995	RET ABN	UG-SERVICE
38429962	GRET	SVC	4/29/2021	1995	RET ABN	UG-SERVICE
39847437	GRET	SVC	3/2/2022	1995	RET ABN	UG-SERVICE
40801474	GRET	SVC	10/12/2022	1995	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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42483429	GRET	SVC	4/15/2024	1995	RET ABN	UG-SERVICE
37102731	GRET	SVC	10/30/2020	1995	RET ABN	UG-SERVICE
42873783	GRET	SVC	4/1/2024	1995	RET ABN	UG-SERVICE
37041376	GRET	SVC	10/8/2020	1995	RET ABN	UG-SERVICE
35835931	GRET	SVC	1/2/2020	1995	RET ABN	UG-SERVICE
37979445	GRET	SVC	1/5/2021	1995	RET ABN	UG-SERVICE
35997397	GRET	SVC	2/10/2020	1995	RET ABN	UG-SERVICE
40813407	GRET	SVC	10/14/2022	1995	RET ABN	UG-SERVICE
40282845	GRET	SVC	6/9/2022	1995	RET ABN	UG-SERVICE
39636945	GRET	SVC	1/3/2022	1995	RET ABN	UG-SERVICE
39831207	GRET	SVC	8/3/2022	1995	RET ABN	UG-SERVICE
41183047	GRET	SVC	1/17/2023	1995	RET ABN	UG-SERVICE
43624700	GRET	SVC	9/30/2024	1995	RET ABN	UG-SERVICE
43812801	GRET	SVC	11/9/2024	1995	RET ABN	UG-SERVICE
43506833	GRET	SVC	9/16/2024	1995	RET ABN	UG-SERVICE
41428826	GRET	SVC	3/24/2023	1995	RET ABN	UG-SERVICE
39468936	GRET	SVC	12/27/2021	1995	RET ABN	UG-SERVICE
39830357	GRET	SVC	8/3/2022	1995	RET ABN	UG-SERVICE
41183046	GRET	SVC	1/17/2023	1995	RET ABN	UG-SERVICE
38766883	GRET	SVC	7/11/2021	1995	RET ABN	UG-SERVICE
40859973	GRET	SVC	11/3/2022	1995	RET ABN	UG-SERVICE
38252498	GRET	SVC	5/3/2021	1995	RET ABN	UG-SERVICE
39318304	GRET	SVC	10/18/2021	1995	RET ABN	UG-SERVICE
40855333	GRET	SVC	10/23/2022	1995	RET ABN	UG-SERVICE
36708021	GRET	SVC	7/28/2020	1995	RET ABN	UG-SERVICE
39658081	GRET	SVC	2/11/2022	1995	RET ABN	UG-SERVICE
41774605	GRET	SVC	6/19/2023	1995	RET ABN	UG-SERVICE
37981636	GRET	SVC	1/5/2021	1995	RET ABN	UG-SERVICE
40853497	GRET	SVC	10/28/2022	1995	RET ABN	UG-SERVICE
36255380	GRET	SVC	3/11/2020	1995	RET ABN	UG-SERVICE
41279363	GRET	SVC	2/15/2023	1995	RET ABN	UG-SERVICE
40092706	GRET	SVC	5/2/2022	1995	RET ABN	UG-SERVICE
38399319	GRET	SVC	4/21/2021	1995	RET ABN	UG-SERVICE
42881713	GRET	SVC	5/8/2024	1995	RET ABN	UG-SERVICE
41887923	GRET	SVC	8/23/2023	1995	RET ABN	UG-SERVICE
41423345	GRET	SVC	3/24/2023	1995	RET ABN	UG-SERVICE
43934140	GRET	SVC	12/21/2024	1995	RET ABN	UG-SERVICE
41589611	GRET	SVC	4/19/2023	1995	RET ABN	UG-SERVICE
43459327	GRET	SVC	8/26/2024	1995	RET ABN	UG-SERVICE
42407919	GRET	SVC	11/19/2023	1995	RET ABN	UG-SERVICE
43650873	GRET	SVC	9/28/2024	1995	RET ABN	UG-SERVICE
43678006	GRET	SVC	10/17/2024	1995	RET ABN	UG-SERVICE
41290031	GRET	SVC	8/31/2023	1995	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41868410	GRET	SVC	7/14/2023	1995	RET ABN	UG-SERVICE
41423927	GRET	SVC	3/22/2023	1995	RET ABN	UG-SERVICE
41322893	GRET	SVC	2/28/2023	1995	RET ABN	UG-SERVICE
38256071	GRET	SVC	3/22/2021	1995	RET ABN	UG-SERVICE
41145679	GRET	SVC	1/13/2023	1995	RET ABN	UG-SERVICE
40545203	GRET	SVC	8/9/2022	1995	RET ABN	UG-SERVICE
39795647	GRET	SVC	2/15/2022	1995	RET ABN	UG-SERVICE
43905495	GRET	SVC	12/23/2024	1996	RET ABN	UG-SERVICE
42938843	GRET	SVC	4/16/2024	1996	RET ABN	UG-SERVICE
42586939	GRET	SVC	1/17/2024	1996	RET ABN	UG-SERVICE
40525193	GRET	SVC	8/8/2022	1996	RET ABN	UG-SERVICE
36184262	GRET	SVC	3/30/2020	1996	RET ABN	UG-SERVICE
40654144	GRET	SVC	9/7/2022	1996	RET ABN	UG-SERVICE
43364924	GRET	SVC	12/2/2024	1996	RET ABN	UG-SERVICE
41545257	GRET	SVC	4/24/2023	1996	RET ABN	UG-SERVICE
40522172	GRET	SVC	9/1/2022	1996	RET ABN	UG-SERVICE
36036302	GRET	SVC	1/9/2020	1996	RET ABN	UG-SERVICE
41102022	GRET	SVC	1/5/2023	1996	RET ABN	UG-SERVICE
38271025	GRET	SVC	3/23/2021	1996	RET ABN	UG-SERVICE
38568364	GRET	SVC	8/18/2021	1996	RET ABN	UG-SERVICE
42087142	GRET	SVC	9/9/2023	1996	RET ABN	UG-SERVICE
38402622	GRET	SVC	4/22/2021	1996	RET ABN	UG-SERVICE
41061141	GRET	SVC	11/30/2022	1996	RET ABN	UG-SERVICE
43428601	GRET	SVC	9/6/2024	1996	RET ABN	UG-SERVICE
40551342	GRET	SVC	8/17/2022	1996	RET ABN	UG-SERVICE
41179720	GRET	SVC	1/17/2023	1996	RET ABN	UG-SERVICE
41407818	GRET	SVC	4/2/2024	1996	RET ABN	UG-SERVICE
43357267	GRET	SVC	7/26/2024	1996	RET ABN	UG-SERVICE
39367029	GRET	SVC	10/22/2021	1996	RET ABN	UG-SERVICE
36963476	GRET	SVC	9/21/2020	1996	RET ABN	UG-SERVICE
43971349	GRET	SVC	12/26/2024	1996	RET ABN	UG-SERVICE
40425685	GRET	SVC	7/12/2022	1996	RET ABN	UG-SERVICE
36310706	GRET	SVC	6/6/2020	1996	RET ABN	UG-SERVICE
36730565	GRET	SVC	8/3/2020	1996	RET ABN	UG-SERVICE
42037856	GRET	SVC	8/27/2023	1996	RET ABN	UG-SERVICE
43950611	GRET	SVC	12/17/2024	1996	RET ABN	UG-SERVICE
43861085	GRET	SVC	12/2/2024	1996	RET ABN	UG-SERVICE
38512754	GRET	SVC	5/17/2021	1996	RET ABN	UG-SERVICE
40481466	GRET	SVC	7/21/2022	1996	RET ABN	UG-SERVICE
39311784	GRET	SVC	11/21/2021	1996	RET ABN	UG-SERVICE
42177914	GRET	SVC	10/6/2023	1996	RET ABN	UG-SERVICE
41664559	GRET	SVC	5/23/2023	1996	RET ABN	UG-SERVICE
42406042	GRET	SVC	11/29/2023	1996	RET ABN	UG-SERVICE
40610690	GRET	SVC	8/23/2022	1996	RET ABN	UG-SERVICE
39795741	GRET	SVC	2/15/2022	1996	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41826324	GRET	SVC	7/26/2023	1996	RET ABN	UG-SERVICE
38352961	GRET	SVC	2/17/2023	1996	RET ABN	UG-SERVICE
42514886	GRET	SVC	2/27/2024	1996	RET ABN	UG-SERVICE
40380288	GRET	SVC	5/23/2022	1996	RET ABN	UG-SERVICE
42372478	GRET	SVC	7/31/2024	1996	RET ABN	UG-SERVICE
36730127	GRET	SVC	8/3/2020	1996	RET ABN	UG-SERVICE
41287836	GRET	SVC	2/16/2023	1996	RET ABN	UG-SERVICE
40999434	GRET	SVC	11/30/2022	1996	RET ABN	UG-SERVICE
37883740	GRET	SVC	12/6/2020	1996	RET ABN	UG-SERVICE
41106614	GRET	SVC	12/27/2022	1996	RET ABN	UG-SERVICE
43916749	GRET	SVC	12/10/2024	1996	RET ABN	UG-SERVICE
35993672	GRET	SVC	2/10/2020	1996	RET ABN	UG-SERVICE
39470796	GRET	SVC	11/30/2021	1996	RET ABN	UG-SERVICE
37934865	GRET	SVC	12/13/2020	1996	RET ABN	UG-SERVICE
42514888	GRET	SVC	2/27/2024	1996	RET ABN	UG-SERVICE
36877204	GRET	SVC	9/3/2020	1996	RET ABN	UG-SERVICE
36480011	GRET	SVC	5/28/2020	1996	RET ABN	UG-SERVICE
40241209	GRET	SVC	5/25/2022	1996	RET ABN	UG-SERVICE
42193971	GRET	SVC	10/9/2023	1996	RET ABN	UG-SERVICE
41767756	GRET	SVC	6/24/2023	1996	RET ABN	UG-SERVICE
40668509	GRET	SVC	9/12/2022	1996	RET ABN	UG-SERVICE
41273851	GRET	SVC	2/13/2023	1996	RET ABN	UG-SERVICE
43071543	GRET	SVC	5/14/2024	1996	RET ABN	UG-SERVICE
41576705	GRET	SVC	5/1/2023	1996	RET ABN	UG-SERVICE
38489445	GRET	SVC	5/12/2021	1996	RET ABN	UG-SERVICE
43364923	GRET	SVC	10/15/2024	1996	RET ABN	UG-SERVICE
42437187	GRET	SVC	12/2/2023	1996	RET ABN	UG-SERVICE
42514885	GRET	SVC	2/27/2024	1996	RET ABN	UG-SERVICE
42514881	GRET	SVC	2/27/2024	1996	RET ABN	UG-SERVICE
39780070	GRET	SVC	2/8/2022	1996	RET ABN	UG-SERVICE
41440502	GRET	SVC	3/27/2023	1996	RET ABN	UG-SERVICE
36691476	GRET	SVC	8/20/2020	1996	RET ABN	UG-SERVICE
41245284	GRET	SVC	2/5/2023	1996	RET ABN	UG-SERVICE
42070933	GRET	SVC	10/6/2023	1996	RET ABN	UG-SERVICE
41274146	GRET	SVC	2/24/2023	1996	RET ABN	UG-SERVICE
39279671	GRET	SVC	10/13/2021	1996	RET ABN	UG-SERVICE
38033806	GRET	SVC	1/21/2021	1996	RET ABN	UG-SERVICE
43244754	GRET	SVC	9/18/2024	1996	RET ABN	UG-SERVICE
42405485	GRET	SVC	11/22/2023	1996	RET ABN	UG-SERVICE
39536369	GRET	SVC	12/14/2021	1996	RET ABN	UG-SERVICE
43318034	GRET	SVC	8/14/2024	1996	RET ABN	UG-SERVICE
41825568	GRET	SVC	7/3/2023	1996	RET ABN	UG-SERVICE
40576551	GRET	SVC	11/21/2022	1996	RET ABN	UG-SERVICE
40987514	GRET	SVC	12/5/2022	1996	RET ABN	UG-SERVICE
42142331	GRET	SVC	10/3/2023	1996	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36730532	GRET	SVC	8/27/2020	1996	RET ABN	UG-SERVICE
41254088	GRET	SVC	2/10/2023	1996	RET ABN	UG-SERVICE
39809219	GRET	SVC	8/3/2022	1996	RET ABN	UG-SERVICE
40332290	GRET	SVC	6/20/2022	1996	RET ABN	UG-SERVICE
43356324	GRET	SVC	7/26/2024	1996	RET ABN	UG-SERVICE
42152239	GRET	SVC	9/25/2023	1996	RET ABN	UG-SERVICE
36152825	GRET	SVC	3/18/2020	1996	RET ABN	UG-SERVICE
37958743	GRET	SVC	12/29/2020	1996	RET ABN	UG-SERVICE
39084028	GRET	SVC	9/12/2021	1996	RET ABN	UG-SERVICE
42692586	GRET	SVC	2/12/2024	1996	RET ABN	UG-SERVICE
42514517	GRET	SVC	2/27/2024	1996	RET ABN	UG-SERVICE
41436546	GRET	SVC	3/26/2023	1996	RET ABN	UG-SERVICE
35994086	GRET	SVC	2/10/2020	1996	RET ABN	UG-SERVICE
35994083	GRET	SVC	2/10/2020	1996	RET ABN	UG-SERVICE
36900245	GRET	SVC	9/8/2020	1996	RET ABN	UG-SERVICE
40576820	GRET	SVC	8/17/2022	1996	RET ABN	UG-SERVICE
42514887	GRET	SVC	3/1/2024	1996	RET ABN	UG-SERVICE
41424021	GRET	SVC	8/7/2023	1996	RET ABN	UG-SERVICE
43916748	GRET	SVC	12/10/2024	1996	RET ABN	UG-SERVICE
42514882	GRET	SVC	2/27/2024	1996	RET ABN	UG-SERVICE
41503107	GRET	SVC	4/13/2023	1996	RET ABN	UG-SERVICE
41791634	GRET	SVC	6/25/2023	1996	RET ABN	UG-SERVICE
42270558	GRET	SVC	10/28/2023	1996	RET ABN	UG-SERVICE
43318486	GRET	SVC	7/19/2024	1996	RET ABN	UG-SERVICE
41906846	GRET	SVC	8/21/2023	1996	RET ABN	UG-SERVICE
36031413	GRET	SVC	2/20/2020	1996	RET ABN	UG-SERVICE
43330520	GRET	SVC	7/16/2024	1996	RET ABN	UG-SERVICE
39162854	GRET	SVC	9/29/2021	1996	RET ABN	UG-SERVICE
35866461	GRET	SVC	1/6/2020	1996	RET ABN	UG-SERVICE
36374976	GRET	SVC	6/1/2020	1996	RET ABN	UG-SERVICE
42227344	GRET	SVC	10/16/2023	1996	RET ABN	UG-SERVICE
39947534	GRET	SVC	3/31/2022	1996	RET ABN	UG-SERVICE
36908265	GRET	SVC	9/8/2020	1996	RET ABN	UG-SERVICE
42514884	GRET	SVC	2/27/2024	1996	RET ABN	UG-SERVICE
42819755	GRET	SVC	3/11/2024	1997	RET ABN	UG-SERVICE
43506837	GRET	SVC	10/3/2024	1997	RET ABN	UG-SERVICE
36184089	GRET	SVC	4/23/2020	1997	RET ABN	UG-SERVICE
42105249	GRET	SVC	9/13/2023	1997	RET ABN	UG-SERVICE
42010596	GRET	SVC	8/18/2023	1997	RET ABN	UG-SERVICE
39423758	GRET	SVC	6/27/2022	1997	RET ABN	UG-SERVICE
37033927	GRET	SVC	11/3/2020	1997	RET ABN	UG-SERVICE
36692253	GRET	SVC	8/6/2020	1997	RET ABN	UG-SERVICE
36835574	GRET	SVC	9/21/2020	1997	RET ABN	UG-SERVICE
40954748	GRET	SVC	11/21/2022	1997	RET ABN	UG-SERVICE
43902245	GRET	SVC	11/30/2024	1997	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39432443	GRET	SVC	11/17/2021	1997	RET ABN	UG-SERVICE
37973319	GRET	SVC	1/25/2021	1997	RET ABN	UG-SERVICE
38134204	GRET	SVC	2/17/2021	1997	RET ABN	UG-SERVICE
36146234	GRET	SVC	3/18/2020	1997	RET ABN	UG-SERVICE
43798077	GRET	SVC	11/7/2024	1997	RET ABN	UG-SERVICE
41872715	GRET	SVC	7/11/2023	1997	RET ABN	UG-SERVICE
36060667	GRET	SVC	3/20/2020	1997	RET ABN	UG-SERVICE
35816991	GRET	SVC	6/15/2021	1997	RET ABN	UG-SERVICE
42796846	GRET	SVC	4/4/2024	1997	RET ABN	UG-SERVICE
42412883	GRET	SVC	11/20/2023	1997	RET ABN	UG-SERVICE
41471664	GRET	SVC	4/4/2023	1997	RET ABN	UG-SERVICE
39280351	GRET	SVC	10/15/2021	1997	RET ABN	UG-SERVICE
41430973	GRET	SVC	3/28/2023	1997	RET ABN	UG-SERVICE
43475964	GRET	SVC	8/26/2024	1997	RET ABN	UG-SERVICE
40487332	GRET	SVC	7/27/2022	1997	RET ABN	UG-SERVICE
41399043	GRET	SVC	3/13/2023	1997	RET ABN	UG-SERVICE
40064748	GRET	SVC	4/29/2022	1997	RET ABN	UG-SERVICE
38437787	GRET	SVC	5/2/2021	1997	RET ABN	UG-SERVICE
40879834	GRET	SVC	10/28/2022	1997	RET ABN	UG-SERVICE
43418899	GRET	SVC	7/31/2024	1997	RET ABN	UG-SERVICE
39338467	GRET	SVC	11/1/2021	1997	RET ABN	UG-SERVICE
43610452	GRET	SVC	9/22/2024	1997	RET ABN	UG-SERVICE
37020175	GRET	SVC	10/1/2020	1997	RET ABN	UG-SERVICE
40824074	GRET	SVC	10/18/2022	1997	RET ABN	UG-SERVICE
39150297	GRET	SVC	9/13/2021	1997	RET ABN	UG-SERVICE
40802935	GRET	SVC	10/13/2022	1997	RET ABN	UG-SERVICE
41399041	GRET	SVC	3/13/2023	1997	RET ABN	UG-SERVICE
39816673	GRET	SVC	2/21/2022	1997	RET ABN	UG-SERVICE
39504173	GRET	SVC	12/6/2021	1997	RET ABN	UG-SERVICE
38240753	GRET	SVC	3/23/2021	1997	RET ABN	UG-SERVICE
36364821	GRET	SVC	6/5/2020	1997	RET ABN	UG-SERVICE
40883585	GRET	SVC	11/7/2022	1997	RET ABN	UG-SERVICE
40871925	GRET	SVC	11/8/2022	1997	RET ABN	UG-SERVICE
41426043	GRET	SVC	3/21/2023	1997	RET ABN	UG-SERVICE
40479240	GRET	SVC	7/25/2022	1997	RET ABN	UG-SERVICE
42297504	GRET	SVC	10/30/2023	1997	RET ABN	UG-SERVICE
40802345	GRET	SVC	10/10/2022	1997	RET ABN	UG-SERVICE
36838651	GRET	SVC	8/29/2020	1997	RET ABN	UG-SERVICE
36540298	GRET	SVC	7/15/2020	1997	RET ABN	UG-SERVICE
38239062	GRET	SVC	3/13/2021	1997	RET ABN	UG-SERVICE
42216810	GRET	SVC	12/6/2023	1997	RET ABN	UG-SERVICE
41129510	GRET	SVC	1/3/2023	1997	RET ABN	UG-SERVICE
36038825	GRET	SVC	2/18/2020	1997	RET ABN	UG-SERVICE
36400479	GRET	SVC	6/5/2020	1997	RET ABN	UG-SERVICE
42216817	GRET	SVC	12/12/2023	1997	RET ABN	UG-SERVICE

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43533818	GRET	SVC	9/6/2024	1997	RET ABN	UG-SERVICE
42216818	GRET	SVC	12/12/2023	1997	RET ABN	UG-SERVICE
36202195	GRET	SVC	4/23/2020	1997	RET ABN	UG-SERVICE
41504298	GRET	SVC	4/14/2023	1997	RET ABN	UG-SERVICE
40784654	GRET	SVC	10/10/2022	1997	RET ABN	UG-SERVICE
42740575	GRET	SVC	2/20/2024	1997	RET ABN	UG-SERVICE
38132322	GRET	SVC	2/4/2021	1997	RET ABN	UG-SERVICE
41213829	GRET	SVC	12/11/2023	1997	RET ABN	UG-SERVICE
36704815	GRET	SVC	7/28/2020	1997	RET ABN	UG-SERVICE
41337380	GRET	SVC	3/6/2023	1997	RET ABN	UG-SERVICE
40871924	GRET	SVC	10/28/2022	1997	RET ABN	UG-SERVICE
41006860	GRET	SVC	12/9/2022	1997	RET ABN	UG-SERVICE
43495960	GRET	SVC	8/29/2024	1997	RET ABN	UG-SERVICE
39783820	GRET	SVC	2/17/2022	1997	RET ABN	UG-SERVICE
41006557	GRET	SVC	12/9/2022	1997	RET ABN	UG-SERVICE
39665275	GRET	SVC	8/3/2022	1997	RET ABN	UG-SERVICE
37422619	GRET	SVC	11/20/2020	1997	RET ABN	UG-SERVICE
38968696	GRET	SVC	8/30/2021	1997	RET ABN	UG-SERVICE
36252177	GRET	SVC	5/5/2020	1997	RET ABN	UG-SERVICE
41568419	GRET	SVC	4/28/2023	1997	RET ABN	UG-SERVICE
40919279	GRET	SVC	11/8/2022	1997	RET ABN	UG-SERVICE
43804914	GRET	SVC	11/21/2024	1997	RET ABN	UG-SERVICE
41088416	GRET	SVC	1/18/2023	1997	RET ABN	UG-SERVICE
40479242	GRET	SVC	7/25/2022	1997	RET ABN	UG-SERVICE
38406800	GRET	SVC	5/9/2021	1997	RET ABN	UG-SERVICE
41694326	GRET	SVC	10/6/2023	1997	RET ABN	UG-SERVICE
39992586	GRET	SVC	4/11/2022	1997	RET ABN	UG-SERVICE
40314683	GRET	SVC	6/15/2022	1997	RET ABN	UG-SERVICE
41006555	GRET	SVC	12/9/2022	1997	RET ABN	UG-SERVICE
42162126	GRET	SVC	9/23/2023	1997	RET ABN	UG-SERVICE
41969493	GRET	SVC	8/1/2024	1997	RET ABN	UG-SERVICE
43324305	GRET	SVC	7/24/2024	1997	RET ABN	UG-SERVICE
43506888	GRET	SVC	9/18/2024	1997	RET ABN	UG-SERVICE
41280027	GRET	SVC	3/3/2023	1997	RET ABN	UG-SERVICE
43396869	GRET	SVC	8/19/2024	1997	RET ABN	UG-SERVICE
41750595	GRET	SVC	6/10/2023	1997	RET ABN	UG-SERVICE
35868778	GRET	SVC	2/11/2020	1997	RET ABN	UG-SERVICE
38727537	GRET	SVC	7/12/2021	1997	RET ABN	UG-SERVICE
39386496	GRET	SVC	11/15/2021	1997	RET ABN	UG-SERVICE
38950424	GRET	SVC	8/17/2021	1997	RET ABN	UG-SERVICE
37606013	GRET	SVC	12/14/2020	1997	RET ABN	UG-SERVICE
41411155	GRET	SVC	4/2/2024	1997	RET ABN	UG-SERVICE
40629974	GRET	SVC	9/2/2022	1997	RET ABN	UG-SERVICE
39966710	GRET	SVC	5/26/2022	1997	RET ABN	UG-SERVICE
43583403	GRET	SVC	9/19/2024	1997	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40954747	GRET	SVC	11/21/2022	1997	RET ABN	UG-SERVICE
42405319	GRET	SVC	11/20/2023	1997	RET ABN	UG-SERVICE
42261815	GRET	SVC	10/23/2023	1997	RET ABN	UG-SERVICE
40954445	GRET	SVC	12/12/2022	1997	RET ABN	UG-SERVICE
36371116	GRET	SVC	5/28/2020	1997	RET ABN	UG-SERVICE
43926050	GRET	SVC	12/11/2024	1997	RET ABN	UG-SERVICE
38875855	GRET	SVC	8/6/2021	1997	RET ABN	UG-SERVICE
40856523	GRET	SVC	10/30/2022	1997	RET ABN	UG-SERVICE
41876593	GRET	SVC	7/10/2023	1997	RET ABN	UG-SERVICE
41450868	GRET	SVC	7/12/2023	1997	RET ABN	UG-SERVICE
42433828	GRET	SVC	12/3/2023	1997	RET ABN	UG-SERVICE
41427496	GRET	SVC	3/28/2023	1997	RET ABN	UG-SERVICE
41213872	GRET	SVC	12/11/2023	1997	RET ABN	UG-SERVICE
43106678	GRET	SVC	5/28/2024	1997	RET ABN	UG-SERVICE
36569971	GRET	SVC	8/12/2020	1997	RET ABN	UG-SERVICE
39183553	GRET	SVC	9/23/2021	1997	RET ABN	UG-SERVICE
37867609	GRET	SVC	11/30/2020	1997	RET ABN	UG-SERVICE
39666090	GRET	SVC	8/3/2022	1997	RET ABN	UG-SERVICE
36392804	GRET	SVC	6/9/2020	1997	RET ABN	UG-SERVICE
41188707	GRET	SVC	1/18/2023	1998	RET ABN	UG-SERVICE
41528624	GRET	SVC	4/23/2023	1998	RET ABN	UG-SERVICE
38767419	GRET	SVC	7/20/2021	1998	RET ABN	UG-SERVICE
40563766	GRET	SVC	8/25/2022	1998	RET ABN	UG-SERVICE
36596097	GRET	SVC	7/29/2020	1998	RET ABN	UG-SERVICE
36826768	GRET	SVC	8/24/2020	1998	RET ABN	UG-SERVICE
41247252	GRET	SVC	2/8/2023	1998	RET ABN	UG-SERVICE
41576608	GRET	SVC	5/2/2023	1998	RET ABN	UG-SERVICE
42681619	GRET	SVC	2/12/2024	1998	RET ABN	UG-SERVICE
43318487	GRET	SVC	8/9/2024	1998	RET ABN	UG-SERVICE
41188703	GRET	SVC	1/20/2023	1998	RET ABN	UG-SERVICE
41195084	GRET	SVC	1/24/2023	1998	RET ABN	UG-SERVICE
42806300	GRET	SVC	3/12/2024	1998	RET ABN	UG-SERVICE
41253572	GRET	SVC	2/6/2023	1998	RET ABN	UG-SERVICE
38940808	GRET	SVC	8/19/2021	1998	RET ABN	UG-SERVICE
41036021	GRET	SVC	1/27/2023	1998	RET ABN	UG-SERVICE
37288381	GRET	SVC	11/9/2020	1998	RET ABN	UG-SERVICE
38791174	GRET	SVC	7/20/2021	1998	RET ABN	UG-SERVICE
41128958	GRET	SVC	1/4/2023	1998	RET ABN	UG-SERVICE
41068184	GRET	SVC	1/10/2023	1998	RET ABN	UG-SERVICE
37000459	GRET	SVC	11/3/2020	1998	RET ABN	UG-SERVICE
36745032	GRET	SVC	7/23/2020	1998	RET ABN	UG-SERVICE
39262300	GRET	SVC	10/26/2021	1998	RET ABN	UG-SERVICE
36792648	GRET	SVC	8/17/2020	1998	RET ABN	UG-SERVICE
39274158	GRET	SVC	10/14/2021	1998	RET ABN	UG-SERVICE
36480152	GRET	SVC	6/19/2020	1998	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41242473	GRET	SVC	2/21/2023	1998	RET ABN	UG-SERVICE
36915601	GRET	SVC	9/8/2020	1998	RET ABN	UG-SERVICE
39610822	GRET	SVC	12/26/2021	1998	RET ABN	UG-SERVICE
43090426	GRET	SVC	5/20/2024	1998	RET ABN	UG-SERVICE
41188567	GRET	SVC	1/19/2023	1998	RET ABN	UG-SERVICE
41472143	GRET	SVC	4/8/2023	1998	RET ABN	UG-SERVICE
40402788	GRET	SVC	7/12/2022	1998	RET ABN	UG-SERVICE
39978074	GRET	SVC	4/6/2022	1998	RET ABN	UG-SERVICE
41242608	GRET	SVC	2/21/2023	1998	RET ABN	UG-SERVICE
42787554	GRET	SVC	3/6/2024	1998	RET ABN	UG-SERVICE
41195093	GRET	SVC	1/27/2023	1998	RET ABN	UG-SERVICE
36435516	GRET	SVC	6/15/2020	1998	RET ABN	UG-SERVICE
40352474	GRET	SVC	7/1/2022	1998	RET ABN	UG-SERVICE
37934848	GRET	SVC	12/19/2020	1998	RET ABN	UG-SERVICE
35980848	GRET	SVC	2/6/2020	1998	RET ABN	UG-SERVICE
39904134	GRET	SVC	3/16/2022	1998	RET ABN	UG-SERVICE
36709896	GRET	SVC	8/5/2020	1998	RET ABN	UG-SERVICE
40141056	GRET	SVC	5/5/2022	1998	RET ABN	UG-SERVICE
41127312	GRET	SVC	1/5/2023	1998	RET ABN	UG-SERVICE
40812721	GRET	SVC	10/12/2022	1998	RET ABN	UG-SERVICE
41847581	GRET	SVC	7/13/2023	1998	RET ABN	UG-SERVICE
40669280	GRET	SVC	9/12/2022	1998	RET ABN	UG-SERVICE
38206744	GRET	SVC	3/13/2021	1998	RET ABN	UG-SERVICE
41188573	GRET	SVC	1/18/2023	1998	RET ABN	UG-SERVICE
38862872	GRET	SVC	8/4/2021	1998	RET ABN	UG-SERVICE
41246607	GRET	SVC	2/6/2023	1998	RET ABN	UG-SERVICE
41083456	GRET	SVC	1/4/2023	1998	RET ABN	UG-SERVICE
38481828	GRET	SVC	5/13/2021	1998	RET ABN	UG-SERVICE
38862875	GRET	SVC	8/4/2021	1998	RET ABN	UG-SERVICE
38769079	GRET	SVC	8/4/2021	1998	RET ABN	UG-SERVICE
41016211	GRET	SVC	12/12/2022	1998	RET ABN	UG-SERVICE
41195087	GRET	SVC	1/24/2023	1998	RET ABN	UG-SERVICE
42269392	GRET	SVC	11/3/2023	1998	RET ABN	UG-SERVICE
40514013	GRET	SVC	9/15/2022	1998	RET ABN	UG-SERVICE
42347999	GRET	SVC	11/20/2023	1998	RET ABN	UG-SERVICE
43469742	GRET	SVC	8/24/2024	1998	RET ABN	UG-SERVICE
41598850	GRET	SVC	5/25/2023	1998	RET ABN	UG-SERVICE
42383762	GRET	SVC	11/17/2023	1998	RET ABN	UG-SERVICE
40282165	GRET	SVC	6/13/2022	1998	RET ABN	UG-SERVICE
36302109	GRET	SVC	5/4/2020	1998	RET ABN	UG-SERVICE
37971361	GRET	SVC	12/29/2020	1998	RET ABN	UG-SERVICE
35933672	GRET	SVC	1/22/2020	1998	RET ABN	UG-SERVICE
39305036	GRET	SVC	10/25/2021	1998	RET ABN	UG-SERVICE
36914878	GRET	SVC	9/16/2020	1998	RET ABN	UG-SERVICE
41300695	GRET	SVC	2/28/2023	1998	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39125203	GRET	SVC	9/14/2021	1998	RET ABN	UG-SERVICE
43409641	GRET	SVC	8/5/2024	1998	RET ABN	UG-SERVICE
39831571	GRET	SVC	8/3/2022	1998	RET ABN	UG-SERVICE
37842345	GRET	SVC	11/30/2020	1998	RET ABN	UG-SERVICE
41194834	GRET	SVC	1/22/2023	1998	RET ABN	UG-SERVICE
40731660	GRET	SVC	9/30/2022	1998	RET ABN	UG-SERVICE
41338302	GRET	SVC	3/1/2023	1998	RET ABN	UG-SERVICE
36710941	GRET	SVC	8/3/2020	1998	RET ABN	UG-SERVICE
41912317	GRET	SVC	7/27/2023	1998	RET ABN	UG-SERVICE
43650607	GRET	SVC	9/30/2024	1998	RET ABN	UG-SERVICE
42925411	GRET	SVC	4/25/2024	1998	RET ABN	UG-SERVICE
41242468	GRET	SVC	3/2/2023	1998	RET ABN	UG-SERVICE
41536200	GRET	SVC	4/18/2023	1998	RET ABN	UG-SERVICE
41974091	GRET	SVC	8/9/2023	1998	RET ABN	UG-SERVICE
43705212	GRET	SVC	10/12/2024	1998	RET ABN	UG-SERVICE
40469681	GRET	SVC	7/14/2022	1998	RET ABN	UG-SERVICE
41969578	GRET	SVC	8/1/2024	1998	RET ABN	UG-SERVICE
41188706	GRET	SVC	1/20/2023	1998	RET ABN	UG-SERVICE
42905583	GRET	SVC	4/1/2024	1998	RET ABN	UG-SERVICE
38862878	GRET	SVC	8/4/2021	1998	RET ABN	UG-SERVICE
41194837	GRET	SVC	1/21/2023	1998	RET ABN	UG-SERVICE
41974945	GRET	SVC	8/16/2023	1998	RET ABN	UG-SERVICE
41194830	GRET	SVC	1/22/2023	1998	RET ABN	UG-SERVICE
41188563	GRET	SVC	1/19/2023	1998	RET ABN	UG-SERVICE
41301033	GRET	SVC	2/20/2023	1998	RET ABN	UG-SERVICE
43464740	GRET	SVC	8/20/2024	1998	RET ABN	UG-SERVICE
41241354	GRET	SVC	3/7/2023	1998	RET ABN	UG-SERVICE
37051179	GRET	SVC	10/9/2020	1998	RET ABN	UG-SERVICE
41253571	GRET	SVC	2/6/2023	1998	RET ABN	UG-SERVICE
36792651	GRET	SVC	8/17/2020	1998	RET ABN	UG-SERVICE
39305663	GRET	SVC	10/18/2021	1998	RET ABN	UG-SERVICE
41194611	GRET	SVC	1/24/2023	1998	RET ABN	UG-SERVICE
42270913	GRET	SVC	10/23/2023	1998	RET ABN	UG-SERVICE
39484323	GRET	SVC	11/30/2021	1998	RET ABN	UG-SERVICE
38954562	GRET	SVC	8/20/2021	1998	RET ABN	UG-SERVICE
41383474	GRET	SVC	3/14/2023	1998	RET ABN	UG-SERVICE
40220224	GRET	SVC	5/26/2022	1998	RET ABN	UG-SERVICE
40093182	GRET	SVC	5/2/2022	1998	RET ABN	UG-SERVICE
38624921	GRET	SVC	5/1/2021	1998	RET ABN	UG-SERVICE
42570377	GRET	SVC	1/18/2024	1998	RET ABN	UG-SERVICE
35973634	GRET	SVC	2/3/2020	1998	RET ABN	UG-SERVICE
37934613	GRET	SVC	12/19/2020	1998	RET ABN	UG-SERVICE
39305039	GRET	SVC	10/25/2021	1998	RET ABN	UG-SERVICE
41503110	GRET	SVC	4/13/2023	1998	RET ABN	UG-SERVICE
41195082	GRET	SVC	1/21/2023	1998	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36914879	GRET	SVC	9/16/2020	1998	RET ABN	UG-SERVICE
39878518	GRET	SVC	6/2/2022	1998	RET ABN	UG-SERVICE
41188571	GRET	SVC	1/18/2023	1998	RET ABN	UG-SERVICE
41195088	GRET	SVC	1/24/2023	1998	RET ABN	UG-SERVICE
41067838	GRET	SVC	1/21/2023	1998	RET ABN	UG-SERVICE
39212890	GRET	SVC	9/28/2021	1998	RET ABN	UG-SERVICE
42914143	GRET	SVC	4/19/2024	1998	RET ABN	UG-SERVICE
42375997	GRET	SVC	11/22/2023	1999	RET ABN	UG-SERVICE
38875933	GRET	SVC	8/5/2021	1999	RET ABN	UG-SERVICE
43611901	GRET	SVC	10/2/2024	1999	RET ABN	UG-SERVICE
41830501	GRET	SVC	9/27/2023	1999	RET ABN	UG-SERVICE
42067507	GRET	SVC	9/6/2023	1999	RET ABN	UG-SERVICE
42216804	GRET	SVC	12/5/2023	1999	RET ABN	UG-SERVICE
40492265	GRET	SVC	8/11/2022	1999	RET ABN	UG-SERVICE
38947394	GRET	SVC	8/26/2021	1999	RET ABN	UG-SERVICE
36684436	GRET	SVC	7/26/2020	1999	RET ABN	UG-SERVICE
42216594	GRET	SVC	12/4/2023	1999	RET ABN	UG-SERVICE
39160109	GRET	SVC	9/12/2021	1999	RET ABN	UG-SERVICE
42453892	GRET	SVC	12/6/2023	1999	RET ABN	UG-SERVICE
38865033	GRET	SVC	8/3/2021	1999	RET ABN	UG-SERVICE
42023961	GRET	SVC	8/21/2023	1999	RET ABN	UG-SERVICE
43610587	GRET	SVC	12/6/2024	1999	RET ABN	UG-SERVICE
39444953	GRET	SVC	12/8/2021	1999	RET ABN	UG-SERVICE
39169287	GRET	SVC	6/3/2021	1999	RET ABN	UG-SERVICE
36016317	GRET	SVC	5/6/2020	1999	RET ABN	UG-SERVICE
38220190	GRET	SVC	3/15/2021	1999	RET ABN	UG-SERVICE
43529804	GRET	SVC	12/13/2024	1999	RET ABN	UG-SERVICE
36567677	GRET	SVC	6/30/2020	1999	RET ABN	UG-SERVICE
42216805	GRET	SVC	12/5/2023	1999	RET ABN	UG-SERVICE
42068096	GRET	SVC	9/13/2023	1999	RET ABN	UG-SERVICE
41428833	GRET	SVC	3/23/2023	1999	RET ABN	UG-SERVICE
43481197	GRET	SVC	11/23/2024	1999	RET ABN	UG-SERVICE
39414253	GRET	SVC	9/30/2021	1999	RET ABN	UG-SERVICE
35863418	GRET	SVC	1/7/2020	1999	RET ABN	UG-SERVICE
41282911	GRET	SVC	2/24/2023	1999	RET ABN	UG-SERVICE
43035947	GRET	SVC	6/7/2024	1999	RET ABN	UG-SERVICE
42660372	GRET	SVC	3/7/2024	1999	RET ABN	UG-SERVICE
39878723	GRET	SVC	6/2/2022	1999	RET ABN	UG-SERVICE
41282906	GRET	SVC	2/21/2023	1999	RET ABN	UG-SERVICE
43378910	GRET	SVC	8/5/2024	1999	RET ABN	UG-SERVICE
40500606	GRET	SVC	8/3/2022	1999	RET ABN	UG-SERVICE
39562050	GRET	SVC	11/8/2021	1999	RET ABN	UG-SERVICE
38358930	GRET	SVC	4/12/2021	1999	RET ABN	UG-SERVICE
39666612	GRET	SVC	11/18/2022	1999	RET ABN	UG-SERVICE
37898367	GRET	SVC	12/8/2020	1999	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43032811	GRET	SVC	7/27/2024	1999	RET ABN	UG-SERVICE
43547058	GRET	SVC	9/15/2024	1999	RET ABN	UG-SERVICE
41140303	GRET	SVC	1/5/2023	1999	RET ABN	UG-SERVICE
42881813	GRET	SVC	4/4/2024	1999	RET ABN	UG-SERVICE
41785388	GRET	SVC	6/22/2023	1999	RET ABN	UG-SERVICE
37892197	GRET	SVC	12/6/2020	1999	RET ABN	UG-SERVICE
37040165	GRET	SVC	10/22/2020	1999	RET ABN	UG-SERVICE
42467509	GRET	SVC	3/4/2024	1999	RET ABN	UG-SERVICE
37879007	GRET	SVC	12/5/2020	1999	RET ABN	UG-SERVICE
40813400	GRET	SVC	10/21/2022	1999	RET ABN	UG-SERVICE
41727399	GRET	SVC	6/8/2023	1999	RET ABN	UG-SERVICE
40018957	GRET	SVC	4/19/2022	1999	RET ABN	UG-SERVICE
36672939	GRET	SVC	7/27/2020	1999	RET ABN	UG-SERVICE
39217533	GRET	SVC	8/20/2021	1999	RET ABN	UG-SERVICE
43481189	GRET	SVC	10/15/2024	1999	RET ABN	UG-SERVICE
37077690	GRET	SVC	10/11/2020	1999	RET ABN	UG-SERVICE
41425689	GRET	SVC	3/26/2023	1999	RET ABN	UG-SERVICE
38642523	GRET	SVC	6/18/2021	1999	RET ABN	UG-SERVICE
43529756	GRET	SVC	12/16/2024	1999	RET ABN	UG-SERVICE
43364877	GRET	SVC	12/13/2024	1999	RET ABN	UG-SERVICE
40416195	GRET	SVC	6/27/2022	1999	RET ABN	UG-SERVICE
37895426	GRET	SVC	12/6/2020	1999	RET ABN	UG-SERVICE
42380213	GRET	SVC	11/29/2023	1999	RET ABN	UG-SERVICE
40446586	GRET	SVC	7/18/2022	1999	RET ABN	UG-SERVICE
42216816	GRET	SVC	12/7/2023	1999	RET ABN	UG-SERVICE
37892560	GRET	SVC	12/6/2020	1999	RET ABN	UG-SERVICE
35870559	GRET	SVC	1/13/2020	1999	RET ABN	UG-SERVICE
39666144	GRET	SVC	8/3/2022	1999	RET ABN	UG-SERVICE
41095697	GRET	SVC	1/17/2023	1999	RET ABN	UG-SERVICE
43145278	GRET	SVC	6/6/2024	1999	RET ABN	UG-SERVICE
40046869	GRET	SVC	12/22/2021	1999	RET ABN	UG-SERVICE
37892199	GRET	SVC	12/6/2020	1999	RET ABN	UG-SERVICE
39657986	GRET	SVC	3/28/2022	1999	RET ABN	UG-SERVICE
37925872	GRET	SVC	12/16/2020	1999	RET ABN	UG-SERVICE
41284193	GRET	SVC	2/15/2023	1999	RET ABN	UG-SERVICE
37077695	GRET	SVC	10/11/2020	1999	RET ABN	UG-SERVICE
43346349	GRET	SVC	7/23/2024	1999	RET ABN	UG-SERVICE
36881818	GRET	SVC	7/31/2020	1999	RET ABN	UG-SERVICE
42315524	GRET	SVC	10/25/2023	1999	RET ABN	UG-SERVICE
40722553	GRET	SVC	9/20/2022	1999	RET ABN	UG-SERVICE
39873511	GRET	SVC	3/15/2022	1999	RET ABN	UG-SERVICE
40613623	GRET	SVC	8/30/2022	1999	RET ABN	UG-SERVICE
40989692	GRET	SVC	12/2/2022	1999	RET ABN	UG-SERVICE
41242477	GRET	SVC	2/10/2023	1999	RET ABN	UG-SERVICE
39510760	GRET	SVC	12/9/2021	1999	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
35535542	GRET	SVC	1/9/2020	1999	RET ABN	UG-SERVICE
40155145	GRET	SVC	5/17/2022	1999	RET ABN	UG-SERVICE
39327948	GRET	SVC	10/27/2021	1999	RET ABN	UG-SERVICE
38191559	GRET	SVC	3/17/2021	1999	RET ABN	UG-SERVICE
36881999	GRET	SVC	8/30/2020	1999	RET ABN	UG-SERVICE
43901506	GRET	SVC	12/13/2024	1999	RET ABN	UG-SERVICE
38879126	GRET	SVC	8/9/2021	1999	RET ABN	UG-SERVICE
40524690	GRET	SVC	8/5/2022	1999	RET ABN	UG-SERVICE
40867635	GRET	SVC	11/7/2022	1999	RET ABN	UG-SERVICE
42434593	GRET	SVC	11/29/2023	1999	RET ABN	UG-SERVICE
36562307	GRET	SVC	7/1/2020	1999	RET ABN	UG-SERVICE
38108091	GRET	SVC	12/22/2021	1999	RET ABN	UG-SERVICE
43481190	GRET	SVC	10/26/2024	1999	RET ABN	UG-SERVICE
42216806	GRET	SVC	12/6/2023	1999	RET ABN	UG-SERVICE
38522082	GRET	SVC	5/21/2021	1999	RET ABN	UG-SERVICE
36495443	GRET	SVC	6/23/2020	1999	RET ABN	UG-SERVICE
41425681	GRET	SVC	3/26/2023	1999	RET ABN	UG-SERVICE
38303368	GRET	SVC	3/26/2021	2000	RET ABN	UG-SERVICE
37707370	GRET	SVC	11/24/2020	2000	RET ABN	UG-SERVICE
36919699	GRET	SVC	9/17/2020	2000	RET ABN	UG-SERVICE
42041818	GRET	SVC	8/28/2023	2000	RET ABN	UG-SERVICE
43889066	GRET	SVC	12/3/2024	2000	RET ABN	UG-SERVICE
36868331	GRET	SVC	8/30/2020	2000	RET ABN	UG-SERVICE
42771048	GRET	SVC	3/1/2024	2000	RET ABN	UG-SERVICE
43623429	GRET	SVC	12/16/2024	2000	RET ABN	UG-SERVICE
42589740	GRET	SVC	1/24/2024	2000	RET ABN	UG-SERVICE
38824668	GRET	SVC	7/28/2021	2000	RET ABN	UG-SERVICE
40802927	GRET	SVC	10/12/2022	2000	RET ABN	UG-SERVICE
36880252	GRET	SVC	9/1/2020	2000	RET ABN	UG-SERVICE
39670256	GRET	SVC	1/10/2022	2000	RET ABN	UG-SERVICE
36433745	GRET	SVC	6/10/2020	2000	RET ABN	UG-SERVICE
39025562	GRET	SVC	9/1/2021	2000	RET ABN	UG-SERVICE
40332125	GRET	SVC	7/8/2022	2000	RET ABN	UG-SERVICE
41968577	GRET	SVC	9/12/2023	2000	RET ABN	UG-SERVICE
43005048	GRET	SVC	9/19/2024	2000	RET ABN	UG-SERVICE
41436809	GRET	SVC	4/13/2023	2000	RET ABN	UG-SERVICE
40802837	GRET	SVC	10/10/2022	2000	RET ABN	UG-SERVICE
38884420	GRET	SVC	7/30/2021	2000	RET ABN	UG-SERVICE
42980534	GRET	SVC	4/23/2024	2000	RET ABN	UG-SERVICE
41064388	GRET	SVC	12/8/2022	2000	RET ABN	UG-SERVICE
41008796	GRET	SVC	12/5/2022	2000	RET ABN	UG-SERVICE
40722885	GRET	SVC	9/21/2022	2000	RET ABN	UG-SERVICE
41030225	GRET	SVC	12/8/2022	2000	RET ABN	UG-SERVICE
37424279	GRET	SVC	11/12/2020	2000	RET ABN	UG-SERVICE
37897527	GRET	SVC	12/11/2020	2000	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40812991	GRET	SVC	10/21/2022	2000	RET ABN	UG-SERVICE
39610702	GRET	SVC	9/21/2021	2000	RET ABN	UG-SERVICE
35844431	GRET	SVC	1/2/2020	2000	RET ABN	UG-SERVICE
43361452	GRET	SVC	7/30/2024	2000	RET ABN	UG-SERVICE
36421667	GRET	SVC	5/19/2020	2000	RET ABN	UG-SERVICE
37078266	GRET	SVC	10/14/2020	2000	RET ABN	UG-SERVICE
43344414	GRET	SVC	7/19/2024	2000	RET ABN	UG-SERVICE
38194555	GRET	SVC	3/12/2021	2000	RET ABN	UG-SERVICE
41431156	GRET	SVC	3/29/2023	2000	RET ABN	UG-SERVICE
42499932	GRET	SVC	12/13/2023	2000	RET ABN	UG-SERVICE
38791569	GRET	SVC	7/22/2021	2000	RET ABN	UG-SERVICE
35926514	GRET	SVC	2/6/2020	2000	RET ABN	UG-SERVICE
43481244	GRET	SVC	10/25/2024	2000	RET ABN	UG-SERVICE
41398463	GRET	SVC	3/15/2023	2000	RET ABN	UG-SERVICE
42177066	GRET	SVC	9/29/2023	2000	RET ABN	UG-SERVICE
41610596	GRET	SVC	5/9/2023	2000	RET ABN	UG-SERVICE
41436550	GRET	SVC	3/29/2023	2000	RET ABN	UG-SERVICE
43338309	GRET	SVC	7/22/2024	2000	RET ABN	UG-SERVICE
38176405	GRET	SVC	3/1/2021	2000	RET ABN	UG-SERVICE
42033600	GRET	SVC	8/23/2023	2000	RET ABN	UG-SERVICE
42866194	GRET	SVC	3/26/2024	2000	RET ABN	UG-SERVICE
38043897	GRET	SVC	1/20/2021	2000	RET ABN	UG-SERVICE
41283334	GRET	SVC	2/13/2023	2000	RET ABN	UG-SERVICE
40343946	GRET	SVC	6/27/2022	2000	RET ABN	UG-SERVICE
36421668	GRET	SVC	5/19/2020	2000	RET ABN	UG-SERVICE
37505359	GRET	SVC	9/20/2020	2000	RET ABN	UG-SERVICE
40802485	GRET	SVC	10/12/2022	2000	RET ABN	UG-SERVICE
40256570	GRET	SVC	6/14/2022	2000	RET ABN	UG-SERVICE
42600007	GRET	SVC	1/20/2024	2000	RET ABN	UG-SERVICE
36783423	GRET	SVC	8/15/2020	2000	RET ABN	UG-SERVICE
43272061	GRET	SVC	7/11/2024	2000	RET ABN	UG-SERVICE
38194559	GRET	SVC	3/12/2021	2000	RET ABN	UG-SERVICE
41064392	GRET	SVC	12/18/2022	2000	RET ABN	UG-SERVICE
37897528	GRET	SVC	12/11/2020	2000	RET ABN	UG-SERVICE
41498150	GRET	SVC	4/21/2023	2000	RET ABN	UG-SERVICE
36571480	GRET	SVC	6/30/2020	2000	RET ABN	UG-SERVICE
41436806	GRET	SVC	4/13/2023	2000	RET ABN	UG-SERVICE
38194704	GRET	SVC	3/10/2021	2000	RET ABN	UG-SERVICE
40883284	GRET	SVC	11/2/2022	2000	RET ABN	UG-SERVICE
40472864	GRET	SVC	7/27/2022	2000	RET ABN	UG-SERVICE
41116479	GRET	SVC	12/29/2022	2000	RET ABN	UG-SERVICE
43480659	GRET	SVC	10/11/2024	2000	RET ABN	UG-SERVICE
43480657	GRET	SVC	10/25/2024	2000	RET ABN	UG-SERVICE
37971090	GRET	SVC	1/5/2021	2000	RET ABN	UG-SERVICE
36049726	GRET	SVC	2/19/2020	2000	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43633368	GRET	SVC	10/2/2024	2000	RET ABN	UG-SERVICE
40921851	GRET	SVC	11/14/2022	2000	RET ABN	UG-SERVICE
41064380	GRET	SVC	12/8/2022	2000	RET ABN	UG-SERVICE
42810562	GRET	SVC	3/11/2024	2000	RET ABN	UG-SERVICE
40629871	GRET	SVC	8/26/2022	2000	RET ABN	UG-SERVICE
41498146	GRET	SVC	4/21/2023	2000	RET ABN	UG-SERVICE
39611828	GRET	SVC	12/28/2021	2000	RET ABN	UG-SERVICE
40395245	GRET	SVC	7/7/2022	2000	RET ABN	UG-SERVICE
41660704	GRET	SVC	5/23/2023	2000	RET ABN	UG-SERVICE
41895787	GRET	SVC	7/24/2023	2000	RET ABN	UG-SERVICE
41932128	GRET	SVC	6/22/2023	2000	RET ABN	UG-SERVICE
40367262	GRET	SVC	6/29/2022	2000	RET ABN	UG-SERVICE
43318025	GRET	SVC	7/19/2024	2000	RET ABN	UG-SERVICE
37000688	GRET	SVC	9/30/2020	2000	RET ABN	UG-SERVICE
41827231	GRET	SVC	7/5/2023	2000	RET ABN	UG-SERVICE
39915194	GRET	SVC	3/21/2022	2000	RET ABN	UG-SERVICE
39998636	GRET	SVC	4/18/2022	2000	RET ABN	UG-SERVICE
42995220	GRET	SVC	7/10/2024	2000	RET ABN	UG-SERVICE
36740596	GRET	SVC	8/8/2020	2000	RET ABN	UG-SERVICE
38176406	GRET	SVC	3/1/2021	2000	RET ABN	UG-SERVICE
40492805	GRET	SVC	7/27/2022	2000	RET ABN	UG-SERVICE
43849373	GRET	SVC	11/15/2024	2000	RET ABN	UG-SERVICE
39235699	GRET	SVC	9/30/2021	2000	RET ABN	UG-SERVICE
41064387	GRET	SVC	12/18/2022	2000	RET ABN	UG-SERVICE
39621131	GRET	SVC	1/4/2022	2000	RET ABN	UG-SERVICE
36173901	GRET	SVC	6/16/2020	2000	RET ABN	UG-SERVICE
42947563	GRET	SVC	4/16/2024	2000	RET ABN	UG-SERVICE
43796589	GRET	SVC	10/31/2024	2000	RET ABN	UG-SERVICE
41064382	GRET	SVC	12/17/2022	2000	RET ABN	UG-SERVICE
39316948	GRET	SVC	10/14/2021	2000	RET ABN	UG-SERVICE
37897531	GRET	SVC	12/11/2020	2000	RET ABN	UG-SERVICE
43613455	GRET	SVC	9/24/2024	2000	RET ABN	UG-SERVICE
43349767	GRET	SVC	7/24/2024	2001	RET ABN	UG-SERVICE
40900097	GRET	SVC	11/7/2022	2001	RET ABN	UG-SERVICE
41045286	GRET	SVC	12/12/2022	2001	RET ABN	UG-SERVICE
41538999	GRET	SVC	4/19/2023	2001	RET ABN	UG-SERVICE
43318358	GRET	SVC	7/31/2024	2001	RET ABN	UG-SERVICE
36418335	GRET	SVC	6/13/2020	2001	RET ABN	UG-SERVICE
38565574	GRET	SVC	6/1/2021	2001	RET ABN	UG-SERVICE
41388776	GRET	SVC	3/17/2023	2001	RET ABN	UG-SERVICE
38706673	GRET	SVC	7/12/2021	2001	RET ABN	UG-SERVICE
43914918	GRET	SVC	12/9/2024	2001	RET ABN	UG-SERVICE
39392830	GRET	SVC	11/9/2021	2001	RET ABN	UG-SERVICE
42967818	GRET	SVC	4/20/2024	2001	RET ABN	UG-SERVICE
39465548	GRET	SVC	11/22/2021	2001	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42073379	GRET	SVC	9/6/2023	2001	RET ABN	UG-SERVICE
43351576	GRET	SVC	7/29/2024	2001	RET ABN	UG-SERVICE
41465015	GRET	SVC	4/4/2023	2001	RET ABN	UG-SERVICE
38343718	GRET	SVC	4/12/2021	2001	RET ABN	UG-SERVICE
39615246	GRET	SVC	12/30/2021	2001	RET ABN	UG-SERVICE
43152901	GRET	SVC	6/11/2024	2001	RET ABN	UG-SERVICE
41969562	GRET	SVC	8/1/2024	2001	RET ABN	UG-SERVICE
40328438	GRET	SVC	7/12/2022	2001	RET ABN	UG-SERVICE
36881982	GRET	SVC	8/29/2020	2001	RET ABN	UG-SERVICE
40191460	GRET	SVC	5/23/2022	2001	RET ABN	UG-SERVICE
43123265	GRET	SVC	4/19/2024	2001	RET ABN	UG-SERVICE
40656085	GRET	SVC	9/7/2022	2001	RET ABN	UG-SERVICE
41273377	GRET	SVC	2/11/2023	2001	RET ABN	UG-SERVICE
40325461	GRET	SVC	6/21/2022	2001	RET ABN	UG-SERVICE
43499674	GRET	SVC	8/29/2024	2001	RET ABN	UG-SERVICE
41891997	GRET	SVC	7/19/2023	2001	RET ABN	UG-SERVICE
41429934	GRET	SVC	9/13/2023	2001	RET ABN	UG-SERVICE
39661991	GRET	SVC	1/19/2022	2001	RET ABN	UG-SERVICE
38192854	GRET	SVC	3/5/2021	2001	RET ABN	UG-SERVICE
41242470	GRET	SVC	2/16/2023	2001	RET ABN	UG-SERVICE
36997699	GRET	SVC	9/24/2020	2001	RET ABN	UG-SERVICE
36983987	GRET	SVC	9/24/2020	2001	RET ABN	UG-SERVICE
41436448	GRET	SVC	3/29/2023	2001	RET ABN	UG-SERVICE
39554485	GRET	SVC	12/23/2021	2001	RET ABN	UG-SERVICE
41485315	GRET	SVC	4/10/2023	2001	RET ABN	UG-SERVICE
43141890	GRET	SVC	6/5/2024	2001	RET ABN	UG-SERVICE
36862809	GRET	SVC	9/2/2020	2001	RET ABN	UG-SERVICE
43932203	GRET	SVC	12/20/2024	2001	RET ABN	UG-SERVICE
42221056	GRET	SVC	10/16/2023	2001	RET ABN	UG-SERVICE
40118446	GRET	SVC	5/2/2022	2001	RET ABN	UG-SERVICE
41283325	GRET	SVC	3/21/2023	2001	RET ABN	UG-SERVICE
38557584	GRET	SVC	6/7/2021	2001	RET ABN	UG-SERVICE
38604359	GRET	SVC	6/7/2021	2001	RET ABN	UG-SERVICE
36881758	GRET	SVC	8/30/2020	2001	RET ABN	UG-SERVICE
36484469	GRET	SVC	6/22/2020	2001	RET ABN	UG-SERVICE
39318777	GRET	SVC	11/2/2021	2001	RET ABN	UG-SERVICE
39891183	GRET	SVC	3/14/2022	2001	RET ABN	UG-SERVICE
40981283	GRET	SVC	11/30/2022	2001	RET ABN	UG-SERVICE
38302256	GRET	SVC	4/8/2021	2001	RET ABN	UG-SERVICE
38163054	GRET	SVC	2/2/2023	2001	RET ABN	UG-SERVICE
43973883	GRET	SVC	12/26/2024	2001	RET ABN	UG-SERVICE
41007407	GRET	SVC	12/16/2022	2001	RET ABN	UG-SERVICE
42418509	GRET	SVC	11/28/2023	2001	RET ABN	UG-SERVICE
36988776	GRET	SVC	10/1/2020	2001	RET ABN	UG-SERVICE
41721316	GRET	SVC	6/8/2023	2001	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38472023	GRET	SVC	5/10/2021	2001	RET ABN	UG-SERVICE
37087269	GRET	SVC	11/20/2020	2001	RET ABN	UG-SERVICE
42157164	GRET	SVC	9/27/2023	2001	RET ABN	UG-SERVICE
38084821	GRET	SVC	2/3/2021	2001	RET ABN	UG-SERVICE
36698308	GRET	SVC	7/28/2020	2001	RET ABN	UG-SERVICE
43494793	GRET	SVC	9/10/2024	2001	RET ABN	UG-SERVICE
40419926	GRET	SVC	6/28/2022	2001	RET ABN	UG-SERVICE
37673227	GRET	SVC	11/17/2020	2001	RET ABN	UG-SERVICE
36724029	GRET	SVC	8/4/2020	2001	RET ABN	UG-SERVICE
41743295	GRET	SVC	6/12/2023	2001	RET ABN	UG-SERVICE
36306576	GRET	SVC	5/26/2020	2001	RET ABN	UG-SERVICE
42967388	GRET	SVC	4/20/2024	2001	RET ABN	UG-SERVICE
43318354	GRET	SVC	8/1/2024	2001	RET ABN	UG-SERVICE
41179728	GRET	SVC	1/19/2023	2001	RET ABN	UG-SERVICE
41273577	GRET	SVC	2/19/2023	2001	RET ABN	UG-SERVICE
41645975	GRET	SVC	5/17/2023	2001	RET ABN	UG-SERVICE
37886691	GRET	SVC	12/7/2020	2001	RET ABN	UG-SERVICE
41640802	GRET	SVC	5/19/2023	2001	RET ABN	UG-SERVICE
41483265	GRET	SVC	4/11/2023	2001	RET ABN	UG-SERVICE
42942077	GRET	SVC	4/17/2024	2001	RET ABN	UG-SERVICE
38413342	GRET	SVC	4/29/2021	2001	RET ABN	UG-SERVICE
35960480	GRET	SVC	1/28/2020	2001	RET ABN	UG-SERVICE
39971774	GRET	SVC	4/7/2022	2001	RET ABN	UG-SERVICE
38571054	GRET	SVC	6/11/2021	2001	RET ABN	UG-SERVICE
36734782	GRET	SVC	8/4/2020	2001	RET ABN	UG-SERVICE
42940123	GRET	SVC	4/17/2024	2001	RET ABN	UG-SERVICE
42409026	GRET	SVC	11/22/2023	2001	RET ABN	UG-SERVICE
41149794	GRET	SVC	1/10/2023	2001	RET ABN	UG-SERVICE
43861502	GRET	SVC	11/20/2024	2001	RET ABN	UG-SERVICE
41016021	GRET	SVC	12/5/2022	2001	RET ABN	UG-SERVICE
37676416	GRET	SVC	11/18/2020	2001	RET ABN	UG-SERVICE
39330668	GRET	SVC	10/26/2021	2001	RET ABN	UG-SERVICE
40883580	GRET	SVC	10/30/2022	2001	RET ABN	UG-SERVICE
38708008	GRET	SVC	7/9/2021	2001	RET ABN	UG-SERVICE
41933549	GRET	SVC	10/4/2023	2001	RET ABN	UG-SERVICE
39554490	GRET	SVC	12/23/2021	2001	RET ABN	UG-SERVICE
43614554	GRET	SVC	10/1/2024	2001	RET ABN	UG-SERVICE
40943532	GRET	SVC	11/13/2022	2001	RET ABN	UG-SERVICE
38194703	GRET	SVC	3/5/2021	2001	RET ABN	UG-SERVICE
36801154	GRET	SVC	8/18/2020	2001	RET ABN	UG-SERVICE
36881756	GRET	SVC	8/30/2020	2001	RET ABN	UG-SERVICE
41697192	GRET	SVC	5/27/2023	2001	RET ABN	UG-SERVICE
43610591	GRET	SVC	11/21/2024	2001	RET ABN	UG-SERVICE
43326668	GRET	SVC	7/27/2024	2001	RET ABN	UG-SERVICE
42380946	GRET	SVC	2/26/2024	2001	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41242465	GRET	SVC	3/7/2023	2001	RET ABN	UG-SERVICE
37887068	GRET	SVC	12/7/2020	2001	RET ABN	UG-SERVICE
42670287	GRET	SVC	9/19/2024	2001	RET ABN	UG-SERVICE
42909599	GRET	SVC	4/11/2024	2001	RET ABN	UG-SERVICE
38862750	GRET	SVC	8/10/2021	2001	RET ABN	UG-SERVICE
37049087	GRET	SVC	10/13/2020	2001	RET ABN	UG-SERVICE
41420887	GRET	SVC	3/22/2023	2001	RET ABN	UG-SERVICE
43890028	GRET	SVC	12/5/2024	2001	RET ABN	UG-SERVICE
39725649	GRET	SVC	1/26/2022	2001	RET ABN	UG-SERVICE
42325245	GRET	SVC	11/7/2023	2001	RET ABN	UG-SERVICE
43267204	GRET	SVC	7/1/2024	2001	RET ABN	UG-SERVICE
41834508	GRET	SVC	8/1/2023	2001	RET ABN	UG-SERVICE
37146457	GRET	SVC	10/26/2020	2001	RET ABN	UG-SERVICE
39661053	GRET	SVC	1/6/2022	2001	RET ABN	UG-SERVICE
41409365	GRET	SVC	3/20/2023	2001	RET ABN	UG-SERVICE
40870057	GRET	SVC	11/7/2022	2001	RET ABN	UG-SERVICE
37084444	GRET	SVC	10/18/2020	2001	RET ABN	UG-SERVICE
38304357	GRET	SVC	4/5/2021	2002	RET ABN	UG-SERVICE
42399667	GRET	SVC	11/22/2023	2002	RET ABN	UG-SERVICE
37810974	GRET	SVC	11/28/2020	2002	RET ABN	UG-SERVICE
41427445	GRET	SVC	3/20/2023	2002	RET ABN	UG-SERVICE
41389205	GRET	SVC	3/11/2023	2002	RET ABN	UG-SERVICE
41245807	GRET	SVC	2/11/2023	2002	RET ABN	UG-SERVICE
37150059	GRET	SVC	10/27/2020	2002	RET ABN	UG-SERVICE
41411077	GRET	SVC	4/2/2024	2002	RET ABN	UG-SERVICE
37064274	GRET	SVC	10/12/2020	2002	RET ABN	UG-SERVICE
37896321	GRET	SVC	12/9/2020	2002	RET ABN	UG-SERVICE
41867849	GRET	SVC	7/30/2023	2002	RET ABN	UG-SERVICE
41073858	GRET	SVC	12/19/2022	2002	RET ABN	UG-SERVICE
37925617	GRET	SVC	12/15/2020	2002	RET ABN	UG-SERVICE
41428201	GRET	SVC	3/17/2023	2002	RET ABN	UG-SERVICE
40526714	GRET	SVC	8/15/2022	2002	RET ABN	UG-SERVICE
41940284	GRET	SVC	7/30/2023	2002	RET ABN	UG-SERVICE
39199257	GRET	SVC	9/16/2021	2002	RET ABN	UG-SERVICE
41578979	GRET	SVC	5/3/2023	2002	RET ABN	UG-SERVICE
36021539	GRET	SVC	2/27/2020	2002	RET ABN	UG-SERVICE
36253908	GRET	SVC	3/8/2021	2002	RET ABN	UG-SERVICE
41447522	GRET	SVC	3/28/2023	2002	RET ABN	UG-SERVICE
41672471	GRET	SVC	5/21/2023	2002	RET ABN	UG-SERVICE
43481129	GRET	SVC	10/17/2024	2002	RET ABN	UG-SERVICE
36068845	GRET	SVC	2/18/2020	2002	RET ABN	UG-SERVICE
38534793	GRET	SVC	5/25/2021	2002	RET ABN	UG-SERVICE
41749481	GRET	SVC	6/15/2023	2002	RET ABN	UG-SERVICE
40474020	GRET	SVC	7/23/2022	2002	RET ABN	UG-SERVICE
40302688	GRET	SVC	6/14/2022	2002	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
39174443	GRET	SVC	9/21/2021	2002	RET ABN	UG-SERVICE
41195274	GRET	SVC	2/3/2023	2002	RET ABN	UG-SERVICE
36731996	GRET	SVC	8/4/2020	2002	RET ABN	UG-SERVICE
41421866	GRET	SVC	3/22/2023	2002	RET ABN	UG-SERVICE
41379689	GRET	SVC	3/14/2023	2002	RET ABN	UG-SERVICE
43879552	GRET	SVC	11/25/2024	2002	RET ABN	UG-SERVICE
41356754	GRET	SVC	3/11/2023	2002	RET ABN	UG-SERVICE
40802652	GRET	SVC	10/14/2022	2002	RET ABN	UG-SERVICE
43480770	GRET	SVC	9/9/2024	2002	RET ABN	UG-SERVICE
42857255	GRET	SVC	3/25/2024	2002	RET ABN	UG-SERVICE
41774861	GRET	SVC	6/19/2023	2002	RET ABN	UG-SERVICE
39165294	GRET	SVC	10/4/2021	2002	RET ABN	UG-SERVICE
35861527	GRET	SVC	1/6/2020	2002	RET ABN	UG-SERVICE
41933968	GRET	SVC	9/7/2023	2002	RET ABN	UG-SERVICE
40143951	GRET	SVC	5/9/2022	2002	RET ABN	UG-SERVICE
35926820	GRET	SVC	1/20/2020	2002	RET ABN	UG-SERVICE
43126530	GRET	SVC	6/10/2024	2002	RET ABN	UG-SERVICE
43481248	GRET	SVC	10/31/2024	2002	RET ABN	UG-SERVICE
43329575	GRET	SVC	7/23/2024	2002	RET ABN	UG-SERVICE
37751453	GRET	SVC	11/24/2020	2002	RET ABN	UG-SERVICE
38415911	GRET	SVC	4/27/2021	2002	RET ABN	UG-SERVICE
36319105	GRET	SVC	9/14/2020	2002	RET ABN	UG-SERVICE
43480656	GRET	SVC	10/6/2024	2002	RET ABN	UG-SERVICE
40903183	GRET	SVC	11/9/2022	2002	RET ABN	UG-SERVICE
35987870	GRET	SVC	2/5/2020	2002	RET ABN	UG-SERVICE
40890406	GRET	SVC	11/7/2022	2002	RET ABN	UG-SERVICE
42846731	GRET	SVC	3/19/2024	2002	RET ABN	UG-SERVICE
41389215	GRET	SVC	3/11/2023	2002	RET ABN	UG-SERVICE
42766384	GRET	SVC	2/29/2024	2002	RET ABN	UG-SERVICE
41447265	GRET	SVC	3/28/2023	2002	RET ABN	UG-SERVICE
41353730	GRET	SVC	3/8/2023	2002	RET ABN	UG-SERVICE
41431601	GRET	SVC	3/29/2023	2002	RET ABN	UG-SERVICE
41379698	GRET	SVC	3/14/2023	2002	RET ABN	UG-SERVICE
42671362	GRET	SVC	2/9/2024	2002	RET ABN	UG-SERVICE
43120501	GRET	SVC	5/28/2024	2002	RET ABN	UG-SERVICE
38566433	GRET	SVC	6/2/2021	2002	RET ABN	UG-SERVICE
41232992	GRET	SVC	1/27/2023	2002	RET ABN	UG-SERVICE
40661316	GRET	SVC	9/8/2022	2002	RET ABN	UG-SERVICE
40103568	GRET	SVC	5/27/2022	2002	RET ABN	UG-SERVICE
40344678	GRET	SVC	6/24/2022	2002	RET ABN	UG-SERVICE
41827373	GRET	SVC	6/29/2023	2002	RET ABN	UG-SERVICE
41127770	GRET	SVC	1/5/2023	2002	RET ABN	UG-SERVICE
42556959	GRET	SVC	1/10/2024	2002	RET ABN	UG-SERVICE
41356022	GRET	SVC	3/11/2023	2002	RET ABN	UG-SERVICE
39084238	GRET	SVC	9/7/2021	2002	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40159959	GRET	SVC	6/6/2022	2002	RET ABN	UG-SERVICE
42044124	GRET	SVC	9/1/2023	2002	RET ABN	UG-SERVICE
38600943	GRET	SVC	10/10/2021	2002	RET ABN	UG-SERVICE
40092080	GRET	SVC	5/2/2022	2002	RET ABN	UG-SERVICE
41347205	GRET	SVC	3/11/2023	2002	RET ABN	UG-SERVICE
41564462	GRET	SVC	4/25/2023	2002	RET ABN	UG-SERVICE
41175129	GRET	SVC	1/18/2023	2002	RET ABN	UG-SERVICE
40989681	GRET	SVC	12/11/2022	2002	RET ABN	UG-SERVICE
43628634	GRET	SVC	10/3/2024	2002	RET ABN	UG-SERVICE
43245004	GRET	SVC	9/19/2024	2002	RET ABN	UG-SERVICE
42947767	GRET	SVC	4/12/2024	2002	RET ABN	UG-SERVICE
40282726	GRET	SVC	6/7/2022	2002	RET ABN	UG-SERVICE
42332589	GRET	SVC	11/9/2023	2002	RET ABN	UG-SERVICE
43870478	GRET	SVC	12/11/2024	2002	RET ABN	UG-SERVICE
37355647	GRET	SVC	11/4/2020	2002	RET ABN	UG-SERVICE
41427444	GRET	SVC	3/22/2023	2002	RET ABN	UG-SERVICE
36792659	GRET	SVC	8/17/2020	2002	RET ABN	UG-SERVICE
41098638	GRET	SVC	12/28/2022	2002	RET ABN	UG-SERVICE
39982794	GRET	SVC	4/11/2022	2002	RET ABN	UG-SERVICE
37003857	GRET	SVC	9/28/2020	2002	RET ABN	UG-SERVICE
40834140	GRET	SVC	10/17/2022	2002	RET ABN	UG-SERVICE
43347675	GRET	SVC	7/30/2024	2002	RET ABN	UG-SERVICE
41389208	GRET	SVC	3/11/2023	2002	RET ABN	UG-SERVICE
38348342	GRET	SVC	4/11/2021	2002	RET ABN	UG-SERVICE
41749310	GRET	SVC	6/12/2023	2002	RET ABN	UG-SERVICE
41389627	GRET	SVC	3/11/2023	2002	RET ABN	UG-SERVICE
39776978	GRET	SVC	2/10/2022	2002	RET ABN	UG-SERVICE
39853683	GRET	SVC	3/7/2022	2003	RET ABN	UG-SERVICE
38200838	GRET	SVC	3/10/2021	2003	RET ABN	UG-SERVICE
36121800	GRET	SVC	10/12/2020	2003	RET ABN	UG-SERVICE
41064399	GRET	SVC	12/13/2022	2003	RET ABN	UG-SERVICE
38470502	GRET	SVC	5/9/2021	2003	RET ABN	UG-SERVICE
41064581	GRET	SVC	12/13/2022	2003	RET ABN	UG-SERVICE
40630791	GRET	SVC	8/24/2022	2003	RET ABN	UG-SERVICE
40549630	GRET	SVC	8/11/2022	2003	RET ABN	UG-SERVICE
41009843	GRET	SVC	12/5/2022	2003	RET ABN	UG-SERVICE
36142357	GRET	SVC	3/17/2020	2003	RET ABN	UG-SERVICE
42427105	GRET	SVC	9/19/2024	2003	RET ABN	UG-SERVICE
42469806	GRET	SVC	12/11/2023	2003	RET ABN	UG-SERVICE
43480655	GRET	SVC	10/10/2024	2003	RET ABN	UG-SERVICE
40549831	GRET	SVC	8/11/2022	2003	RET ABN	UG-SERVICE
35841979	GRET	SVC	2/5/2020	2003	RET ABN	UG-SERVICE
40572770	GRET	SVC	8/24/2022	2003	RET ABN	UG-SERVICE
36622900	GRET	SVC	7/14/2020	2003	RET ABN	UG-SERVICE
40036010	GRET	SVC	5/9/2022	2003	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
37926602	GRET	SVC	12/13/2020	2003	RET ABN	UG-SERVICE
39715818	GRET	SVC	4/11/2022	2003	RET ABN	UG-SERVICE
43541484	GRET	SVC	9/7/2024	2003	RET ABN	UG-SERVICE
42203265	GRET	SVC	10/9/2023	2003	RET ABN	UG-SERVICE
37044199	GRET	SVC	10/8/2020	2003	RET ABN	UG-SERVICE
40247527	GRET	SVC	6/3/2022	2003	RET ABN	UG-SERVICE
39831648	GRET	SVC	8/3/2022	2003	RET ABN	UG-SERVICE
39724678	GRET	SVC	2/14/2022	2003	RET ABN	UG-SERVICE
42257656	GRET	SVC	10/17/2023	2003	RET ABN	UG-SERVICE
37107895	GRET	SVC	11/3/2020	2003	RET ABN	UG-SERVICE
41056876	GRET	SVC	12/14/2022	2003	RET ABN	UG-SERVICE
39970682	GRET	SVC	6/17/2022	2003	RET ABN	UG-SERVICE
40513377	GRET	SVC	8/2/2022	2003	RET ABN	UG-SERVICE
37935101	GRET	SVC	12/20/2020	2003	RET ABN	UG-SERVICE
43645446	GRET	SVC	10/2/2024	2003	RET ABN	UG-SERVICE
41062120	GRET	SVC	12/15/2022	2003	RET ABN	UG-SERVICE
40549745	GRET	SVC	8/11/2022	2003	RET ABN	UG-SERVICE
36370810	GRET	SVC	5/26/2020	2003	RET ABN	UG-SERVICE
37995172	GRET	SVC	1/7/2021	2003	RET ABN	UG-SERVICE
41407581	GRET	SVC	4/2/2024	2003	RET ABN	UG-SERVICE
40549515	GRET	SVC	8/11/2022	2003	RET ABN	UG-SERVICE
41062957	GRET	SVC	12/13/2022	2003	RET ABN	UG-SERVICE
36482418	GRET	SVC	6/24/2020	2003	RET ABN	UG-SERVICE
38312389	GRET	SVC	10/5/2021	2003	RET ABN	UG-SERVICE
40501628	GRET	SVC	8/1/2022	2003	RET ABN	UG-SERVICE
40549218	GRET	SVC	8/11/2022	2003	RET ABN	UG-SERVICE
38466241	GRET	SVC	5/11/2021	2003	RET ABN	UG-SERVICE
40371595	GRET	SVC	7/6/2022	2003	RET ABN	UG-SERVICE
42300691	GRET	SVC	10/30/2023	2003	RET ABN	UG-SERVICE
41896727	GRET	SVC	7/22/2023	2003	RET ABN	UG-SERVICE
43244858	GRET	SVC	9/19/2024	2003	RET ABN	UG-SERVICE
40498905	GRET	SVC	7/28/2022	2003	RET ABN	UG-SERVICE
36169905	GRET	SVC	4/23/2020	2003	RET ABN	UG-SERVICE
43222767	GRET	SVC	6/24/2024	2003	RET ABN	UG-SERVICE
41258462	GRET	SVC	3/14/2023	2003	RET ABN	UG-SERVICE
42520538	GRET	SVC	12/27/2023	2003	RET ABN	UG-SERVICE
40975075	GRET	SVC	11/28/2022	2003	RET ABN	UG-SERVICE
36982532	GRET	SVC	9/21/2020	2003	RET ABN	UG-SERVICE
36917243	GRET	SVC	9/10/2020	2003	RET ABN	UG-SERVICE
42860042	GRET	SVC	3/27/2024	2003	RET ABN	UG-SERVICE
43529739	GRET	SVC	12/6/2024	2003	RET ABN	UG-SERVICE
39772389	GRET	SVC	2/7/2022	2003	RET ABN	UG-SERVICE
36185118	GRET	SVC	4/23/2020	2003	RET ABN	UG-SERVICE
38720222	GRET	SVC	7/8/2021	2003	RET ABN	UG-SERVICE
43345642	GRET	SVC	7/23/2024	2004	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42356134	GRET	SVC	11/13/2023	2004	RET ABN	UG-SERVICE
38917715	GRET	SVC	9/10/2021	2004	RET ABN	UG-SERVICE
36283351	GRET	SVC	4/28/2020	2004	RET ABN	UG-SERVICE
42073632	GRET	SVC	9/1/2023	2004	RET ABN	UG-SERVICE
40233704	GRET	SVC	6/1/2022	2004	RET ABN	UG-SERVICE
42857414	GRET	SVC	3/25/2024	2004	RET ABN	UG-SERVICE
40599515	GRET	SVC	8/23/2022	2004	RET ABN	UG-SERVICE
39725947	GRET	SVC	1/26/2022	2004	RET ABN	UG-SERVICE
41143393	GRET	SVC	7/31/2023	2004	RET ABN	UG-SERVICE
43439588	GRET	SVC	8/15/2024	2004	RET ABN	UG-SERVICE
40658454	GRET	SVC	9/9/2022	2004	RET ABN	UG-SERVICE
41243163	GRET	SVC	2/5/2023	2004	RET ABN	UG-SERVICE
39449955	GRET	SVC	11/22/2021	2004	RET ABN	UG-SERVICE
43861615	GRET	SVC	12/4/2024	2004	RET ABN	UG-SERVICE
35768208	GRET	SVC	1/8/2020	2004	RET ABN	UG-SERVICE
43480983	GRET	SVC	10/6/2024	2004	RET ABN	UG-SERVICE
37020402	GRET	SVC	10/6/2020	2004	RET ABN	UG-SERVICE
38531959	GRET	SVC	6/24/2021	2004	RET ABN	UG-SERVICE
42586652	GRET	SVC	1/24/2024	2004	RET ABN	UG-SERVICE
42834266	GRET	SVC	8/5/2024	2004	RET ABN	UG-SERVICE
41513768	GRET	SVC	4/17/2023	2004	RET ABN	UG-SERVICE
36473507	GRET	SVC	6/16/2020	2004	RET ABN	UG-SERVICE
41242287	GRET	SVC	2/6/2023	2004	RET ABN	UG-SERVICE
42871432	GRET	SVC	3/30/2024	2004	RET ABN	UG-SERVICE
41063698	GRET	SVC	12/17/2022	2004	RET ABN	UG-SERVICE
41062537	GRET	SVC	12/15/2022	2004	RET ABN	UG-SERVICE
37006649	GRET	SVC	10/6/2020	2004	RET ABN	UG-SERVICE
40271975	GRET	SVC	6/9/2022	2004	RET ABN	UG-SERVICE
40812988	GRET	SVC	10/17/2022	2004	RET ABN	UG-SERVICE
41513769	GRET	SVC	4/17/2023	2004	RET ABN	UG-SERVICE
41062651	GRET	SVC	12/16/2022	2004	RET ABN	UG-SERVICE
41513764	GRET	SVC	4/17/2023	2004	RET ABN	UG-SERVICE
43948545	GRET	SVC	12/18/2024	2004	RET ABN	UG-SERVICE
41513760	GRET	SVC	4/16/2023	2004	RET ABN	UG-SERVICE
36303943	GRET	SVC	5/7/2020	2004	RET ABN	UG-SERVICE
41082594	GRET	SVC	1/12/2023	2004	RET ABN	UG-SERVICE
43041512	GRET	SVC	5/16/2024	2004	RET ABN	UG-SERVICE
42337122	GRET	SVC	11/29/2023	2004	RET ABN	UG-SERVICE
41436449	GRET	SVC	3/29/2023	2004	RET ABN	UG-SERVICE
37521263	GRET	SVC	11/13/2020	2004	RET ABN	UG-SERVICE
37811363	GRET	SVC	11/23/2020	2004	RET ABN	UG-SERVICE
41273663	GRET	SVC	3/16/2023	2004	RET ABN	UG-SERVICE
36730902	GRET	SVC	9/20/2020	2004	RET ABN	UG-SERVICE
36273752	GRET	SVC	5/8/2020	2004	RET ABN	UG-SERVICE
38944874	GRET	SVC	8/7/2021	2004	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40513962	GRET	SVC	8/1/2022	2004	RET ABN	UG-SERVICE
39126371	GRET	SVC	9/15/2021	2004	RET ABN	UG-SERVICE
41082950	GRET	SVC	1/5/2023	2004	RET ABN	UG-SERVICE
36303951	GRET	SVC	5/7/2020	2004	RET ABN	UG-SERVICE
39613259	GRET	SVC	12/29/2021	2004	RET ABN	UG-SERVICE
38060055	GRET	SVC	1/27/2021	2004	RET ABN	UG-SERVICE
41064396	GRET	SVC	12/8/2022	2004	RET ABN	UG-SERVICE
41283626	GRET	SVC	2/21/2023	2004	RET ABN	UG-SERVICE
36760761	GRET	SVC	8/11/2020	2004	RET ABN	UG-SERVICE
40208463	GRET	SVC	5/25/2022	2004	RET ABN	UG-SERVICE
41185736	GRET	SVC	1/27/2023	2004	RET ABN	UG-SERVICE
41082953	GRET	SVC	1/7/2023	2004	RET ABN	UG-SERVICE
40205522	GRET	SVC	5/23/2022	2004	RET ABN	UG-SERVICE
38631228	GRET	SVC	8/4/2021	2004	RET ABN	UG-SERVICE
41513766	GRET	SVC	4/17/2023	2004	RET ABN	UG-SERVICE
36977167	GRET	SVC	9/25/2020	2004	RET ABN	UG-SERVICE
36834103	GRET	SVC	8/29/2020	2004	RET ABN	UG-SERVICE
40652843	GRET	SVC	9/7/2022	2004	RET ABN	UG-SERVICE
41116665	GRET	SVC	1/21/2023	2004	RET ABN	UG-SERVICE
39542353	GRET	SVC	12/15/2021	2004	RET ABN	UG-SERVICE
38126148	GRET	SVC	2/15/2021	2004	RET ABN	UG-SERVICE
36609220	GRET	SVC	7/13/2020	2004	RET ABN	UG-SERVICE
36367091	GRET	SVC	5/27/2020	2004	RET ABN	UG-SERVICE
36304192	GRET	SVC	5/7/2020	2004	RET ABN	UG-SERVICE
41354136	GRET	SVC	3/13/2023	2004	RET ABN	UG-SERVICE
36303948	GRET	SVC	5/7/2020	2004	RET ABN	UG-SERVICE
43480982	GRET	SVC	10/6/2024	2004	RET ABN	UG-SERVICE
36839754	GRET	SVC	8/31/2020	2004	RET ABN	UG-SERVICE
40149164	GRET	SVC	5/17/2022	2004	RET ABN	UG-SERVICE
43618773	GRET	SVC	10/1/2024	2004	RET ABN	UG-SERVICE
41082951	GRET	SVC	1/7/2023	2004	RET ABN	UG-SERVICE
41243166	GRET	SVC	2/5/2023	2004	RET ABN	UG-SERVICE
37933095	GRET	SVC	12/14/2020	2004	RET ABN	UG-SERVICE
42164320	GRET	SVC	9/28/2023	2004	RET ABN	UG-SERVICE
36303952	GRET	SVC	5/7/2020	2004	RET ABN	UG-SERVICE
41436541	GRET	SVC	3/26/2023	2004	RET ABN	UG-SERVICE
39466802	GRET	SVC	11/27/2021	2004	RET ABN	UG-SERVICE
42412971	GRET	SVC	11/27/2023	2004	RET ABN	UG-SERVICE
36379833	GRET	SVC	6/1/2020	2004	RET ABN	UG-SERVICE
40344160	GRET	SVC	6/17/2022	2004	RET ABN	UG-SERVICE
37524106	GRET	SVC	11/13/2020	2004	RET ABN	UG-SERVICE
38807486	GRET	SVC	7/17/2021	2004	RET ABN	UG-SERVICE
43250333	GRET	SVC	12/11/2024	2004	RET ABN	UG-SERVICE
39317784	GRET	SVC	12/7/2021	2004	RET ABN	UG-SERVICE
40899533	GRET	SVC	11/11/2022	2004	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41185739	GRET	SVC	1/19/2023	2004	RET ABN	UG-SERVICE
42804378	GRET	SVC	3/9/2024	2004	RET ABN	UG-SERVICE
40867627	GRET	SVC	12/1/2022	2004	RET ABN	UG-SERVICE
37247562	GRET	SVC	11/2/2020	2004	RET ABN	UG-SERVICE
41144909	GRET	SVC	6/10/2024	2004	RET ABN	UG-SERVICE
41062644	GRET	SVC	12/15/2022	2004	RET ABN	UG-SERVICE
38187064	GRET	SVC	3/3/2021	2004	RET ABN	UG-SERVICE
37845210	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
41187060	GRET	SVC	1/18/2023	2005	RET ABN	UG-SERVICE
39360486	GRET	SVC	11/8/2021	2005	RET ABN	UG-SERVICE
41740862	GRET	SVC	6/13/2023	2005	RET ABN	UG-SERVICE
41117167	GRET	SVC	1/9/2023	2005	RET ABN	UG-SERVICE
38206747	GRET	SVC	3/10/2021	2005	RET ABN	UG-SERVICE
37845209	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
43624426	GRET	SVC	10/2/2024	2005	RET ABN	UG-SERVICE
40609430	GRET	SVC	8/25/2022	2005	RET ABN	UG-SERVICE
43481132	GRET	SVC	10/17/2024	2005	RET ABN	UG-SERVICE
37845208	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
37844978	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
43269460	GRET	SVC	7/6/2024	2005	RET ABN	UG-SERVICE
38206558	GRET	SVC	3/10/2021	2005	RET ABN	UG-SERVICE
36135027	GRET	SVC	3/17/2020	2005	RET ABN	UG-SERVICE
37845203	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
36036306	GRET	SVC	1/9/2020	2005	RET ABN	UG-SERVICE
43343790	GRET	SVC	7/30/2024	2005	RET ABN	UG-SERVICE
37989381	GRET	SVC	1/6/2021	2005	RET ABN	UG-SERVICE
39258151	GRET	SVC	10/12/2021	2005	RET ABN	UG-SERVICE
37844979	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
41289009	GRET	SVC	2/13/2023	2005	RET ABN	UG-SERVICE
37845200	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
37845201	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
36696343	GRET	SVC	7/27/2020	2005	RET ABN	UG-SERVICE
42188716	GRET	SVC	9/21/2023	2005	RET ABN	UG-SERVICE
41401971	GRET	SVC	3/9/2023	2005	RET ABN	UG-SERVICE
43205682	GRET	SVC	6/19/2024	2005	RET ABN	UG-SERVICE
41140329	GRET	SVC	12/31/2022	2005	RET ABN	UG-SERVICE
41083518	GRET	SVC	12/20/2022	2005	RET ABN	UG-SERVICE
42011212	GRET	SVC	8/16/2023	2005	RET ABN	UG-SERVICE
36962408	GRET	SVC	9/21/2020	2005	RET ABN	UG-SERVICE
41223064	GRET	SVC	1/31/2023	2005	RET ABN	UG-SERVICE
41284360	GRET	SVC	2/13/2023	2005	RET ABN	UG-SERVICE
36735977	GRET	SVC	8/10/2020	2005	RET ABN	UG-SERVICE
36827003	GRET	SVC	8/25/2020	2005	RET ABN	UG-SERVICE
37845205	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
43348357	GRET	SVC	7/24/2024	2005	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41062216	GRET	SVC	12/14/2022	2005	RET ABN	UG-SERVICE
38472037	GRET	SVC	5/10/2021	2005	RET ABN	UG-SERVICE
37844977	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
37845206	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
41186311	GRET	SVC	1/28/2023	2005	RET ABN	UG-SERVICE
41064314	GRET	SVC	12/15/2022	2005	RET ABN	UG-SERVICE
36564211	GRET	SVC	6/29/2020	2005	RET ABN	UG-SERVICE
43480997	GRET	SVC	11/16/2024	2005	RET ABN	UG-SERVICE
38520272	GRET	SVC	5/24/2021	2005	RET ABN	UG-SERVICE
41032548	GRET	SVC	12/15/2022	2005	RET ABN	UG-SERVICE
41062525	GRET	SVC	12/15/2022	2005	RET ABN	UG-SERVICE
37083566	GRET	SVC	10/19/2020	2005	RET ABN	UG-SERVICE
42185137	GRET	SVC	10/4/2023	2005	RET ABN	UG-SERVICE
41741068	GRET	SVC	6/13/2023	2005	RET ABN	UG-SERVICE
43480999	GRET	SVC	11/16/2024	2005	RET ABN	UG-SERVICE
37844976	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
42844671	GRET	SVC	3/20/2024	2005	RET ABN	UG-SERVICE
41062211	GRET	SVC	12/14/2022	2005	RET ABN	UG-SERVICE
39361790	GRET	SVC	11/2/2021	2005	RET ABN	UG-SERVICE
38677273	GRET	SVC	6/21/2021	2005	RET ABN	UG-SERVICE
37845204	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
39666497	GRET	SVC	11/18/2022	2005	RET ABN	UG-SERVICE
43075757	GRET	SVC	5/18/2024	2005	RET ABN	UG-SERVICE
43481133	GRET	SVC	11/1/2024	2005	RET ABN	UG-SERVICE
41183051	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
41032545	GRET	SVC	12/4/2022	2005	RET ABN	UG-SERVICE
43053838	GRET	SVC	5/8/2024	2005	RET ABN	UG-SERVICE
41282902	GRET	SVC	3/21/2023	2005	RET ABN	UG-SERVICE
41186308	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
41183057	GRET	SVC	1/20/2023	2005	RET ABN	UG-SERVICE
36744906	GRET	SVC	7/27/2020	2005	RET ABN	UG-SERVICE
37844974	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
41067829	GRET	SVC	12/22/2022	2005	RET ABN	UG-SERVICE
42866971	GRET	SVC	3/28/2024	2005	RET ABN	UG-SERVICE
37845207	GRET	SVC	12/3/2020	2005	RET ABN	UG-SERVICE
41025862	GRET	SVC	4/4/2023	2005	RET ABN	UG-SERVICE
41414164	GRET	SVC	4/2/2023	2005	RET ABN	UG-SERVICE
42957328	GRET	SVC	9/19/2024	2005	RET ABN	UG-SERVICE
41183055	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
35866707	GRET	SVC	1/7/2020	2005	RET ABN	UG-SERVICE
41327963	GRET	SVC	3/1/2023	2005	RET ABN	UG-SERVICE
39495065	GRET	SVC	12/8/2021	2005	RET ABN	UG-SERVICE
39998931	GRET	SVC	4/12/2022	2005	RET ABN	UG-SERVICE
36760744	GRET	SVC	8/10/2020	2005	RET ABN	UG-SERVICE
42628090	GRET	SVC	1/29/2024	2005	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41067832	GRET	SVC	2/4/2023	2005	RET ABN	UG-SERVICE
43329574	GRET	SVC	7/17/2024	2005	RET ABN	UG-SERVICE
41411191	GRET	SVC	4/2/2024	2005	RET ABN	UG-SERVICE
42177396	GRET	SVC	10/4/2023	2005	RET ABN	UG-SERVICE
38360334	GRET	SVC	4/12/2021	2005	RET ABN	UG-SERVICE
38248451	GRET	SVC	3/22/2021	2005	RET ABN	UG-SERVICE
42404191	GRET	SVC	11/20/2023	2005	RET ABN	UG-SERVICE
42076364	GRET	SVC	9/8/2023	2005	RET ABN	UG-SERVICE
38392796	GRET	SVC	4/23/2021	2005	RET ABN	UG-SERVICE
32667124	GRET	SVC	11/1/2020	2005	RET ABN	UG-SERVICE
38259673	GRET	SVC	3/23/2021	2005	RET ABN	UG-SERVICE
42744058	GRET	SVC	2/21/2024	2005	RET ABN	UG-SERVICE
41183045	GRET	SVC	1/17/2023	2005	RET ABN	UG-SERVICE
42652005	GRET	SVC	1/27/2024	2005	RET ABN	UG-SERVICE
43625732	GRET	SVC	9/30/2024	2005	RET ABN	UG-SERVICE
41396611	GRET	SVC	3/14/2023	2005	RET ABN	UG-SERVICE
42856665	GRET	SVC	3/28/2024	2005	RET ABN	UG-SERVICE
42006733	GRET	SVC	8/14/2023	2005	RET ABN	UG-SERVICE
43481252	GRET	SVC	11/20/2024	2005	RET ABN	UG-SERVICE
37052386	GRET	SVC	10/27/2020	2005	RET ABN	UG-SERVICE
42195313	GRET	SVC	10/11/2023	2005	RET ABN	UG-SERVICE
39291666	GRET	SVC	10/6/2021	2005	RET ABN	UG-SERVICE
40202961	GRET	SVC	5/24/2022	2005	RET ABN	UG-SERVICE
41186317	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
40394911	GRET	SVC	7/8/2022	2005	RET ABN	UG-SERVICE
41119750	GRET	SVC	12/31/2022	2005	RET ABN	UG-SERVICE
38305722	GRET	SVC	7/15/2021	2005	RET ABN	UG-SERVICE
41062428	GRET	SVC	12/14/2022	2005	RET ABN	UG-SERVICE
41186062	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
41183048	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
40394311	GRET	SVC	7/6/2022	2005	RET ABN	UG-SERVICE
35909730	GRET	SVC	1/12/2020	2005	RET ABN	UG-SERVICE
39548807	GRET	SVC	12/15/2021	2005	RET ABN	UG-SERVICE
42166505	GRET	SVC	10/17/2023	2005	RET ABN	UG-SERVICE
43611858	GRET	SVC	9/26/2024	2005	RET ABN	UG-SERVICE
43912027	GRET	SVC	12/9/2024	2005	RET ABN	UG-SERVICE
37999544	GRET	SVC	1/12/2021	2005	RET ABN	UG-SERVICE
38069924	GRET	SVC	1/25/2021	2005	RET ABN	UG-SERVICE
43021506	GRET	SVC	5/6/2024	2005	RET ABN	UG-SERVICE
42701523	GRET	SVC	2/13/2024	2005	RET ABN	UG-SERVICE
42896956	GRET	SVC	4/7/2024	2005	RET ABN	UG-SERVICE
40395626	GRET	SVC	6/30/2022	2005	RET ABN	UG-SERVICE
43449545	GRET	SVC	8/20/2024	2005	RET ABN	UG-SERVICE
41594544	GRET	SVC	5/4/2023	2005	RET ABN	UG-SERVICE
41223068	GRET	SVC	1/31/2023	2005	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40462862	GRET	SVC	7/14/2022	2005	RET ABN	UG-SERVICE
38671323	GRET	SVC	6/24/2021	2005	RET ABN	UG-SERVICE
36009163	GRET	SVC	2/12/2020	2005	RET ABN	UG-SERVICE
41186313	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
38693632	GRET	SVC	7/2/2021	2005	RET ABN	UG-SERVICE
41183049	GRET	SVC	1/19/2023	2005	RET ABN	UG-SERVICE
40843791	GRET	SVC	10/20/2022	2005	RET ABN	UG-SERVICE
41309567	GRET	SVC	2/20/2023	2005	RET ABN	UG-SERVICE
43963333	GRET	SVC	12/20/2024	2006	RET ABN	UG-SERVICE
41141838	GRET	SVC	1/9/2023	2006	RET ABN	UG-SERVICE
42670806	GRET	SVC	2/6/2024	2006	RET ABN	UG-SERVICE
38260816	GRET	SVC	3/22/2021	2006	RET ABN	UG-SERVICE
38522085	GRET	SVC	5/21/2021	2006	RET ABN	UG-SERVICE
43988607	GRET	SVC	11/15/2024	2006	RET ABN	UG-SERVICE
39704501	GRET	SVC	1/18/2022	2006	RET ABN	UG-SERVICE
37834464	GRET	SVC	11/30/2020	2006	RET ABN	UG-SERVICE
43341174	GRET	SVC	7/22/2024	2006	RET ABN	UG-SERVICE
41955449	GRET	SVC	7/29/2023	2006	RET ABN	UG-SERVICE
39294222	GRET	SVC	10/22/2021	2006	RET ABN	UG-SERVICE
41408151	GRET	SVC	4/2/2024	2006	RET ABN	UG-SERVICE
38813115	GRET	SVC	7/28/2021	2006	RET ABN	UG-SERVICE
41498362	GRET	SVC	4/12/2023	2006	RET ABN	UG-SERVICE
43806038	GRET	SVC	11/9/2024	2006	RET ABN	UG-SERVICE
42407800	GRET	SVC	11/26/2023	2006	RET ABN	UG-SERVICE
37848585	GRET	SVC	8/14/2020	2006	RET ABN	UG-SERVICE
40863773	GRET	SVC	11/2/2022	2006	RET ABN	UG-SERVICE
42177175	GRET	SVC	10/11/2023	2006	RET ABN	UG-SERVICE
42806286	GRET	SVC	3/11/2024	2006	RET ABN	UG-SERVICE
39823211	GRET	SVC	2/24/2022	2006	RET ABN	UG-SERVICE
41414101	GRET	SVC	3/20/2023	2006	RET ABN	UG-SERVICE
43880122	GRET	SVC	12/2/2024	2006	RET ABN	UG-SERVICE
39301611	GRET	SVC	10/15/2021	2006	RET ABN	UG-SERVICE
37958745	GRET	SVC	12/30/2020	2006	RET ABN	UG-SERVICE
40407299	GRET	SVC	7/11/2022	2006	RET ABN	UG-SERVICE
37390631	GRET	SVC	11/9/2020	2006	RET ABN	UG-SERVICE
42177707	GRET	SVC	10/3/2023	2006	RET ABN	UG-SERVICE
40660400	GRET	SVC	10/22/2022	2006	RET ABN	UG-SERVICE
38813117	GRET	SVC	3/28/2022	2006	RET ABN	UG-SERVICE
43529722	GRET	SVC	12/12/2024	2006	RET ABN	UG-SERVICE
40050319	GRET	SVC	4/27/2022	2006	RET ABN	UG-SERVICE
41119419	GRET	SVC	1/3/2023	2006	RET ABN	UG-SERVICE
40137222	GRET	SVC	5/11/2022	2006	RET ABN	UG-SERVICE
41831517	GRET	SVC	8/2/2023	2006	RET ABN	UG-SERVICE
43204005	GRET	SVC	6/18/2024	2006	RET ABN	UG-SERVICE
42816064	GRET	SVC	3/11/2024	2006	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43610733	GRET	SVC	11/20/2024	2006	RET ABN	UG-SERVICE
39463481	GRET	SVC	11/24/2021	2006	RET ABN	UG-SERVICE
38603475	GRET	SVC	6/10/2021	2006	RET ABN	UG-SERVICE
43481198	GRET	SVC	10/26/2024	2006	RET ABN	UG-SERVICE
40264988	GRET	SVC	6/8/2022	2006	RET ABN	UG-SERVICE
41348986	GRET	SVC	3/8/2023	2006	RET ABN	UG-SERVICE
42491871	GRET	SVC	12/19/2023	2006	RET ABN	UG-SERVICE
42283675	GRET	SVC	10/23/2023	2006	RET ABN	UG-SERVICE
39387615	GRET	SVC	11/5/2021	2006	RET ABN	UG-SERVICE
43640145	GRET	SVC	10/21/2024	2006	RET ABN	UG-SERVICE
43015590	GRET	SVC	5/6/2024	2006	RET ABN	UG-SERVICE
40870520	GRET	SVC	11/11/2022	2006	RET ABN	UG-SERVICE
42205155	GRET	SVC	10/19/2023	2006	RET ABN	UG-SERVICE
40395845	GRET	SVC	7/7/2022	2006	RET ABN	UG-SERVICE
40375048	GRET	SVC	7/2/2022	2006	RET ABN	UG-SERVICE
39665816	GRET	SVC	8/3/2022	2006	RET ABN	UG-SERVICE
38934707	GRET	SVC	8/18/2021	2006	RET ABN	UG-SERVICE
39213492	GRET	SVC	9/27/2021	2006	RET ABN	UG-SERVICE
39386292	GRET	SVC	11/4/2021	2006	RET ABN	UG-SERVICE
43324187	GRET	SVC	7/31/2024	2006	RET ABN	UG-SERVICE
43825012	GRET	SVC	11/22/2024	2006	RET ABN	UG-SERVICE
43141717	GRET	SVC	6/5/2024	2006	RET ABN	UG-SERVICE
40283218	GRET	SVC	6/10/2022	2006	RET ABN	UG-SERVICE
43730825	GRET	SVC	11/12/2024	2006	RET ABN	UG-SERVICE
42411040	GRET	SVC	11/28/2023	2006	RET ABN	UG-SERVICE
42414850	GRET	SVC	11/28/2023	2006	RET ABN	UG-SERVICE
41482813	GRET	SVC	4/14/2023	2006	RET ABN	UG-SERVICE
40283362	GRET	SVC	7/7/2022	2006	RET ABN	UG-SERVICE
37021085	GRET	SVC	10/22/2020	2007	RET ABN	UG-SERVICE
41328009	GRET	SVC	2/27/2023	2007	RET ABN	UG-SERVICE
37489727	GRET	SVC	11/13/2020	2007	RET ABN	UG-SERVICE
41767990	GRET	SVC	6/19/2023	2007	RET ABN	UG-SERVICE
38806234	GRET	SVC	7/29/2021	2007	RET ABN	UG-SERVICE
38786374	GRET	SVC	7/16/2021	2007	RET ABN	UG-SERVICE
36558770	GRET	SVC	7/1/2020	2007	RET ABN	UG-SERVICE
41101937	GRET	SVC	1/4/2023	2007	RET ABN	UG-SERVICE
42299743	GRET	SVC	10/26/2023	2007	RET ABN	UG-SERVICE
37425453	GRET	SVC	11/10/2020	2007	RET ABN	UG-SERVICE
41169124	GRET	SVC	1/18/2023	2007	RET ABN	UG-SERVICE
42619921	GRET	SVC	1/26/2024	2007	RET ABN	UG-SERVICE
39522293	GRET	SVC	12/13/2021	2007	RET ABN	UG-SERVICE
43512388	GRET	SVC	8/28/2024	2007	RET ABN	UG-SERVICE
43481123	GRET	SVC	11/1/2024	2007	RET ABN	UG-SERVICE
39380043	GRET	SVC	11/30/2021	2007	RET ABN	UG-SERVICE
35996870	GRET	SVC	2/10/2020	2007	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41964412	GRET	SVC	8/5/2023	2007	RET ABN	UG-SERVICE
43957833	GRET	SVC	12/17/2024	2007	RET ABN	UG-SERVICE
39857550	GRET	SVC	3/9/2022	2007	RET ABN	UG-SERVICE
43707751	GRET	SVC	10/18/2024	2007	RET ABN	UG-SERVICE
39582342	GRET	SVC	12/27/2021	2007	RET ABN	UG-SERVICE
43481125	GRET	SVC	11/1/2024	2007	RET ABN	UG-SERVICE
43481126	GRET	SVC	10/28/2024	2007	RET ABN	UG-SERVICE
40744624	GRET	SVC	9/15/2022	2007	RET ABN	UG-SERVICE
40498165	GRET	SVC	7/28/2022	2007	RET ABN	UG-SERVICE
39817269	GRET	SVC	2/21/2022	2007	RET ABN	UG-SERVICE
43481196	GRET	SVC	10/22/2024	2007	RET ABN	UG-SERVICE
38496694	GRET	SVC	5/17/2021	2007	RET ABN	UG-SERVICE
38333410	GRET	SVC	4/7/2021	2007	RET ABN	UG-SERVICE
40578829	GRET	SVC	8/16/2022	2007	RET ABN	UG-SERVICE
42506032	GRET	SVC	1/25/2024	2007	RET ABN	UG-SERVICE
38955853	GRET	SVC	8/23/2021	2007	RET ABN	UG-SERVICE
42409561	GRET	SVC	12/1/2023	2007	RET ABN	UG-SERVICE
43481124	GRET	SVC	11/1/2024	2007	RET ABN	UG-SERVICE
38886044	GRET	SVC	8/17/2021	2007	RET ABN	UG-SERVICE
37286086	GRET	SVC	11/17/2020	2007	RET ABN	UG-SERVICE
39524056	GRET	SVC	12/16/2021	2007	RET ABN	UG-SERVICE
41769563	GRET	SVC	6/19/2023	2007	RET ABN	UG-SERVICE
42526243	GRET	SVC	12/30/2023	2007	RET ABN	UG-SERVICE
43318027	GRET	SVC	8/15/2024	2007	RET ABN	UG-SERVICE
36379239	GRET	SVC	6/1/2020	2007	RET ABN	UG-SERVICE
40035079	GRET	SVC	4/27/2022	2007	RET ABN	UG-SERVICE
38424653	GRET	SVC	4/27/2021	2007	RET ABN	UG-SERVICE
38060234	GRET	SVC	1/27/2021	2007	RET ABN	UG-SERVICE
40265835	GRET	SVC	6/6/2022	2007	RET ABN	UG-SERVICE
43619269	GRET	SVC	9/26/2024	2007	RET ABN	UG-SERVICE
38677464	GRET	SVC	6/19/2021	2007	RET ABN	UG-SERVICE
41411296	GRET	SVC	4/2/2024	2007	RET ABN	UG-SERVICE
42434178	GRET	SVC	12/4/2023	2007	RET ABN	UG-SERVICE
41088619	GRET	SVC	1/12/2023	2007	RET ABN	UG-SERVICE
41464744	GRET	SVC	4/3/2023	2007	RET ABN	UG-SERVICE
39772297	GRET	SVC	2/8/2022	2007	RET ABN	UG-SERVICE
41470722	GRET	SVC	8/9/2023	2007	RET ABN	UG-SERVICE
39665140	GRET	SVC	4/28/2022	2007	RET ABN	UG-SERVICE
41606248	GRET	SVC	5/30/2023	2007	RET ABN	UG-SERVICE
37286897	GRET	SVC	11/2/2020	2007	RET ABN	UG-SERVICE
38671327	GRET	SVC	6/24/2021	2007	RET ABN	UG-SERVICE
42155781	GRET	SVC	9/27/2023	2007	RET ABN	UG-SERVICE
39340651	GRET	SVC	10/26/2021	2007	RET ABN	UG-SERVICE
42098400	GRET	SVC	9/13/2023	2007	RET ABN	UG-SERVICE
36779225	GRET	SVC	8/26/2020	2007	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36645610	GRET	SVC	7/17/2020	2007	RET ABN	UG-SERVICE
42201919	GRET	SVC	10/10/2023	2007	RET ABN	UG-SERVICE
39435286	GRET	SVC	11/18/2021	2007	RET ABN	UG-SERVICE
43237027	GRET	SVC	6/28/2024	2007	RET ABN	UG-SERVICE
42612663	GRET	SVC	1/24/2024	2007	RET ABN	UG-SERVICE
40668633	GRET	SVC	9/10/2022	2007	RET ABN	UG-SERVICE
43930806	GRET	SVC	12/13/2024	2008	RET ABN	UG-SERVICE
42069706	GRET	SVC	9/18/2023	2008	RET ABN	UG-SERVICE
39550222	GRET	SVC	12/17/2021	2008	RET ABN	UG-SERVICE
36014715	GRET	SVC	2/13/2020	2008	RET ABN	UG-SERVICE
38709766	GRET	SVC	8/9/2021	2008	RET ABN	UG-SERVICE
36183404	GRET	SVC	4/22/2020	2008	RET ABN	UG-SERVICE
42224049	GRET	SVC	10/12/2023	2008	RET ABN	UG-SERVICE
40277356	GRET	SVC	6/13/2022	2008	RET ABN	UG-SERVICE
41418736	GRET	SVC	3/22/2023	2008	RET ABN	UG-SERVICE
41222213	GRET	SVC	1/30/2023	2008	RET ABN	UG-SERVICE
37096589	GRET	SVC	10/21/2020	2008	RET ABN	UG-SERVICE
40961898	GRET	SVC	11/21/2022	2008	RET ABN	UG-SERVICE
39944269	GRET	SVC	3/28/2022	2008	RET ABN	UG-SERVICE
39084337	GRET	SVC	9/9/2021	2008	RET ABN	UG-SERVICE
40505927	GRET	SVC	8/3/2022	2008	RET ABN	UG-SERVICE
43488867	GRET	SVC	8/28/2024	2008	RET ABN	UG-SERVICE
42370897	GRET	SVC	11/12/2023	2008	RET ABN	UG-SERVICE
38335991	GRET	SVC	4/16/2021	2008	RET ABN	UG-SERVICE
40282852	GRET	SVC	6/9/2022	2008	RET ABN	UG-SERVICE
40119196	GRET	SVC	6/14/2022	2008	RET ABN	UG-SERVICE
36095960	GRET	SVC	3/10/2020	2008	RET ABN	UG-SERVICE
43970938	GRET	SVC	12/23/2024	2008	RET ABN	UG-SERVICE
41144401	GRET	SVC	1/9/2023	2008	RET ABN	UG-SERVICE
42549392	GRET	SVC	1/2/2024	2008	RET ABN	UG-SERVICE
39202978	GRET	SVC	9/27/2021	2008	RET ABN	UG-SERVICE
41408242	GRET	SVC	3/22/2023	2008	RET ABN	UG-SERVICE
43712063	GRET	SVC	10/15/2024	2008	RET ABN	UG-SERVICE
38260769	GRET	SVC	12/17/2021	2008	RET ABN	UG-SERVICE
36561319	GRET	SVC	7/6/2020	2008	RET ABN	UG-SERVICE
43560442	GRET	SVC	9/14/2024	2008	RET ABN	UG-SERVICE
43151062	GRET	SVC	6/6/2024	2008	RET ABN	UG-SERVICE
43343193	GRET	SVC	7/16/2024	2008	RET ABN	UG-SERVICE
41287923	GRET	SVC	2/24/2023	2008	RET ABN	UG-SERVICE
38625200	GRET	SVC	6/24/2021	2008	RET ABN	UG-SERVICE
42691748	GRET	SVC	2/9/2024	2008	RET ABN	UG-SERVICE
36775157	GRET	SVC	7/30/2020	2008	RET ABN	UG-SERVICE
43499910	GRET	SVC	9/11/2024	2008	RET ABN	UG-SERVICE
43173058	GRET	SVC	6/13/2024	2008	RET ABN	UG-SERVICE
36878398	GRET	SVC	9/9/2020	2008	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42131095	GRET	SVC	9/18/2023	2008	RET ABN	UG-SERVICE
41142226	GRET	SVC	1/10/2023	2008	RET ABN	UG-SERVICE
41090671	GRET	SVC	1/23/2023	2008	RET ABN	UG-SERVICE
43861747	GRET	SVC	11/30/2024	2008	RET ABN	UG-SERVICE
38287715	GRET	SVC	3/30/2021	2008	RET ABN	UG-SERVICE
41430052	GRET	SVC	9/12/2023	2008	RET ABN	UG-SERVICE
38472032	GRET	SVC	5/11/2021	2008	RET ABN	UG-SERVICE
42656640	GRET	SVC	2/10/2024	2008	RET ABN	UG-SERVICE
35316597	GRET	SVC	1/22/2021	2008	RET ABN	UG-SERVICE
41408202	GRET	SVC	10/19/2023	2008	RET ABN	UG-SERVICE
37005519	GRET	SVC	9/29/2020	2008	RET ABN	UG-SERVICE
38137996	GRET	SVC	2/17/2021	2008	RET ABN	UG-SERVICE
36893329	GRET	SVC	9/8/2020	2008	RET ABN	UG-SERVICE
43712064	GRET	SVC	10/15/2024	2008	RET ABN	UG-SERVICE
39992560	GRET	SVC	4/12/2022	2008	RET ABN	UG-SERVICE
39720312	GRET	SVC	3/4/2022	2008	RET ABN	UG-SERVICE
38478322	GRET	SVC	5/6/2021	2008	RET ABN	UG-SERVICE
41322605	GRET	SVC	2/28/2023	2008	RET ABN	UG-SERVICE
42942046	GRET	SVC	4/13/2024	2008	RET ABN	UG-SERVICE
38202903	GRET	SVC	3/9/2021	2008	RET ABN	UG-SERVICE
41204527	GRET	SVC	1/25/2023	2008	RET ABN	UG-SERVICE
41296497	GRET	SVC	4/12/2023	2008	RET ABN	UG-SERVICE
39713420	GRET	SVC	1/21/2022	2009	RET ABN	UG-SERVICE
43481259	GRET	SVC	11/22/2024	2009	RET ABN	UG-SERVICE
40352820	GRET	SVC	6/28/2022	2009	RET ABN	UG-SERVICE
40318814	GRET	SVC	6/20/2022	2009	RET ABN	UG-SERVICE
41411489	GRET	SVC	4/2/2024	2009	RET ABN	UG-SERVICE
43605022	GRET	SVC	10/2/2024	2009	RET ABN	UG-SERVICE
38084194	GRET	SVC	2/3/2021	2009	RET ABN	UG-SERVICE
41277502	GRET	SVC	2/13/2023	2009	RET ABN	UG-SERVICE
40667896	GRET	SVC	9/26/2022	2009	RET ABN	UG-SERVICE
43529733	GRET	SVC	12/6/2024	2009	RET ABN	UG-SERVICE
39884636	GRET	SVC	4/23/2022	2009	RET ABN	UG-SERVICE
43651758	GRET	SVC	10/15/2024	2009	RET ABN	UG-SERVICE
41088773	GRET	SVC	12/21/2022	2009	RET ABN	UG-SERVICE
43459229	GRET	SVC	8/19/2024	2009	RET ABN	UG-SERVICE
40951751	GRET	SVC	12/2/2022	2009	RET ABN	UG-SERVICE
41750998	GRET	SVC	6/10/2023	2009	RET ABN	UG-SERVICE
42524186	GRET	SVC	12/28/2023	2009	RET ABN	UG-SERVICE
38594189	GRET	SVC	6/7/2021	2009	RET ABN	UG-SERVICE
38034059	GRET	SVC	1/20/2021	2009	RET ABN	UG-SERVICE
37960957	GRET	SVC	12/28/2020	2009	RET ABN	UG-SERVICE
42407316	GRET	SVC	11/22/2023	2009	RET ABN	UG-SERVICE
42258901	GRET	SVC	10/25/2023	2009	RET ABN	UG-SERVICE
41232154	GRET	SVC	2/20/2023	2009	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42235258	GRET	SVC	11/28/2023	2009	RET ABN	UG-SERVICE
35871725	GRET	SVC	1/4/2020	2009	RET ABN	UG-SERVICE
42524581	GRET	SVC	12/28/2023	2009	RET ABN	UG-SERVICE
38657089	GRET	SVC	6/16/2021	2009	RET ABN	UG-SERVICE
43119125	GRET	SVC	6/3/2024	2009	RET ABN	UG-SERVICE
43904545	GRET	SVC	12/4/2024	2009	RET ABN	UG-SERVICE
38173384	GRET	SVC	3/1/2021	2009	RET ABN	UG-SERVICE
41224539	GRET	SVC	1/30/2023	2009	RET ABN	UG-SERVICE
36878399	GRET	SVC	8/29/2020	2009	RET ABN	UG-SERVICE
40888112	GRET	SVC	11/3/2022	2009	RET ABN	UG-SERVICE
38956799	GRET	SVC	8/16/2021	2009	RET ABN	UG-SERVICE
41430207	GRET	SVC	9/13/2023	2009	RET ABN	UG-SERVICE
43481127	GRET	SVC	11/20/2024	2009	RET ABN	UG-SERVICE
43506447	GRET	SVC	9/9/2024	2009	RET ABN	UG-SERVICE
42484655	GRET	SVC	12/14/2023	2009	RET ABN	UG-SERVICE
42462283	GRET	SVC	12/6/2023	2009	RET ABN	UG-SERVICE
40513128	GRET	SVC	8/3/2022	2009	RET ABN	UG-SERVICE
41843448	GRET	SVC	7/10/2023	2009	RET ABN	UG-SERVICE
42391577	GRET	SVC	11/14/2023	2009	RET ABN	UG-SERVICE
36811300	GRET	SVC	8/24/2020	2009	RET ABN	UG-SERVICE
40903887	GRET	SVC	11/10/2022	2009	RET ABN	UG-SERVICE
37897122	GRET	SVC	12/11/2020	2009	RET ABN	UG-SERVICE
38231096	GRET	SVC	3/16/2021	2009	RET ABN	UG-SERVICE
43324505	GRET	SVC	10/25/2024	2009	RET ABN	UG-SERVICE
40728687	GRET	SVC	9/27/2022	2009	RET ABN	UG-SERVICE
39900986	GRET	SVC	3/16/2022	2009	RET ABN	UG-SERVICE
43481128	GRET	SVC	11/20/2024	2009	RET ABN	UG-SERVICE
37016098	GRET	SVC	9/28/2020	2009	RET ABN	UG-SERVICE
42114053	GRET	SVC	9/11/2023	2009	RET ABN	UG-SERVICE
40283360	GRET	SVC	6/9/2022	2009	RET ABN	UG-SERVICE
40395852	GRET	SVC	7/6/2022	2009	RET ABN	UG-SERVICE
41205872	GRET	SVC	1/21/2023	2009	RET ABN	UG-SERVICE
37915191	GRET	SVC	12/18/2020	2009	RET ABN	UG-SERVICE
42070602	GRET	SVC	11/19/2023	2009	RET ABN	UG-SERVICE
39875959	GRET	SVC	3/10/2022	2009	RET ABN	UG-SERVICE
39719888	GRET	SVC	2/4/2022	2009	RET ABN	UG-SERVICE
35993663	GRET	SVC	2/7/2020	2009	RET ABN	UG-SERVICE
36393452	GRET	SVC	6/4/2020	2009	RET ABN	UG-SERVICE
41755630	GRET	SVC	6/10/2023	2009	RET ABN	UG-SERVICE
40492811	GRET	SVC	8/3/2022	2009	RET ABN	UG-SERVICE
39603680	GRET	SVC	1/5/2022	2009	RET ABN	UG-SERVICE
41976754	GRET	SVC	9/5/2023	2009	RET ABN	UG-SERVICE
43151638	GRET	SVC	7/15/2024	2009	RET ABN	UG-SERVICE
42520179	GRET	SVC	12/27/2023	2009	RET ABN	UG-SERVICE
36009289	GRET	SVC	2/11/2020	2009	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36199839	GRET	SVC	4/30/2020	2010	RET ABN	UG-SERVICE
36652216	GRET	SVC	7/11/2020	2010	RET ABN	UG-SERVICE
43324507	GRET	SVC	10/25/2024	2010	RET ABN	UG-SERVICE
41513275	GRET	SVC	4/16/2023	2010	RET ABN	UG-SERVICE
43318357	GRET	SVC	8/14/2024	2010	RET ABN	UG-SERVICE
41381455	GRET	SVC	3/13/2023	2010	RET ABN	UG-SERVICE
39269783	GRET	SVC	10/11/2021	2010	RET ABN	UG-SERVICE
43427487	GRET	SVC	8/23/2024	2010	RET ABN	UG-SERVICE
41711815	GRET	SVC	6/6/2023	2010	RET ABN	UG-SERVICE
41514001	GRET	SVC	4/16/2023	2010	RET ABN	UG-SERVICE
37958744	GRET	SVC	12/27/2020	2010	RET ABN	UG-SERVICE
41274151	GRET	SVC	2/24/2023	2010	RET ABN	UG-SERVICE
41520903	GRET	SVC	4/26/2023	2010	RET ABN	UG-SERVICE
37033139	GRET	SVC	10/7/2020	2010	RET ABN	UG-SERVICE
40407526	GRET	SVC	7/11/2022	2010	RET ABN	UG-SERVICE
38481836	GRET	SVC	5/11/2021	2010	RET ABN	UG-SERVICE
41520494	GRET	SVC	4/25/2023	2010	RET ABN	UG-SERVICE
38747521	GRET	SVC	7/7/2021	2010	RET ABN	UG-SERVICE
40049852	GRET	SVC	4/26/2022	2010	RET ABN	UG-SERVICE
41513267	GRET	SVC	4/15/2023	2010	RET ABN	UG-SERVICE
41513271	GRET	SVC	4/15/2023	2010	RET ABN	UG-SERVICE
40113656	GRET	SVC	5/2/2022	2010	RET ABN	UG-SERVICE
41513278	GRET	SVC	4/16/2023	2010	RET ABN	UG-SERVICE
40655359	GRET	SVC	9/8/2022	2010	RET ABN	UG-SERVICE
36342461	GRET	SVC	5/21/2020	2010	RET ABN	UG-SERVICE
40120303	GRET	SVC	5/4/2022	2010	RET ABN	UG-SERVICE
41279873	GRET	SVC	2/15/2023	2010	RET ABN	UG-SERVICE
42404945	GRET	SVC	11/22/2023	2010	RET ABN	UG-SERVICE
39386488	GRET	SVC	11/5/2021	2010	RET ABN	UG-SERVICE
40318189	GRET	SVC	6/17/2022	2010	RET ABN	UG-SERVICE
41429980	GRET	SVC	9/13/2023	2010	RET ABN	UG-SERVICE
41646069	GRET	SVC	5/17/2023	2010	RET ABN	UG-SERVICE
38086943	GRET	SVC	2/3/2021	2010	RET ABN	UG-SERVICE
43807761	GRET	SVC	11/15/2024	2010	RET ABN	UG-SERVICE
41514005	GRET	SVC	4/17/2023	2010	RET ABN	UG-SERVICE
41514003	GRET	SVC	4/17/2023	2010	RET ABN	UG-SERVICE
41585567	GRET	SVC	5/2/2023	2010	RET ABN	UG-SERVICE
43529742	GRET	SVC	12/13/2024	2010	RET ABN	UG-SERVICE
42672732	GRET	SVC	2/9/2024	2010	RET ABN	UG-SERVICE
37035464	GRET	SVC	10/7/2020	2010	RET ABN	UG-SERVICE
41424227	GRET	SVC	10/18/2023	2010	RET ABN	UG-SERVICE
42580209	GRET	SVC	1/17/2024	2010	RET ABN	UG-SERVICE
42376980	GRET	SVC	5/9/2024	2010	RET ABN	UG-SERVICE
36760383	GRET	SVC	8/10/2020	2010	RET ABN	UG-SERVICE
41514004	GRET	SVC	4/17/2023	2010	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36142342	GRET	SVC	3/17/2020	2010	RET ABN	UG-SERVICE
41508103	GRET	SVC	4/10/2023	2011	RET ABN	UG-SERVICE
40813628	GRET	SVC	10/20/2022	2011	RET ABN	UG-SERVICE
40282630	GRET	SVC	6/7/2022	2011	RET ABN	UG-SERVICE
41528289	GRET	SVC	4/27/2023	2011	RET ABN	UG-SERVICE
41520915	GRET	SVC	4/18/2023	2011	RET ABN	UG-SERVICE
38065680	GRET	SVC	2/22/2021	2011	RET ABN	UG-SERVICE
38332060	GRET	SVC	4/3/2021	2011	RET ABN	UG-SERVICE
41528290	GRET	SVC	4/21/2023	2011	RET ABN	UG-SERVICE
43318340	GRET	SVC	8/12/2024	2011	RET ABN	UG-SERVICE
43520224	GRET	SVC	8/28/2024	2011	RET ABN	UG-SERVICE
41347944	GRET	SVC	3/6/2023	2011	RET ABN	UG-SERVICE
38333227	GRET	SVC	4/7/2021	2011	RET ABN	UG-SERVICE
40391600	GRET	SVC	7/5/2022	2011	RET ABN	UG-SERVICE
36682175	GRET	SVC	7/27/2020	2011	RET ABN	UG-SERVICE
39860392	GRET	SVC	3/22/2022	2011	RET ABN	UG-SERVICE
40358503	GRET	SVC	7/28/2022	2011	RET ABN	UG-SERVICE
41770076	GRET	SVC	6/19/2023	2011	RET ABN	UG-SERVICE
41520907	GRET	SVC	4/14/2023	2011	RET ABN	UG-SERVICE
41284362	GRET	SVC	3/1/2023	2011	RET ABN	UG-SERVICE
41520918	GRET	SVC	4/18/2023	2011	RET ABN	UG-SERVICE
40855539	GRET	SVC	10/24/2022	2011	RET ABN	UG-SERVICE
41209116	GRET	SVC	1/24/2023	2011	RET ABN	UG-SERVICE
38716142	GRET	SVC	7/7/2021	2011	RET ABN	UG-SERVICE
40208622	GRET	SVC	5/31/2022	2011	RET ABN	UG-SERVICE
42300544	GRET	SVC	10/30/2023	2011	RET ABN	UG-SERVICE
43208316	GRET	SVC	6/22/2024	2011	RET ABN	UG-SERVICE
41528621	GRET	SVC	4/23/2023	2011	RET ABN	UG-SERVICE
41204523	GRET	SVC	1/25/2023	2011	RET ABN	UG-SERVICE
40399903	GRET	SVC	7/11/2022	2011	RET ABN	UG-SERVICE
40037443	GRET	SVC	5/24/2022	2011	RET ABN	UG-SERVICE
43506836	GRET	SVC	10/4/2024	2011	RET ABN	UG-SERVICE
41528442	GRET	SVC	4/23/2023	2011	RET ABN	UG-SERVICE
42909568	GRET	SVC	4/10/2024	2011	RET ABN	UG-SERVICE
41287748	GRET	SVC	3/19/2023	2011	RET ABN	UG-SERVICE
39533060	GRET	SVC	12/14/2021	2011	RET ABN	UG-SERVICE
41521121	GRET	SVC	4/21/2023	2011	RET ABN	UG-SERVICE
39318350	GRET	SVC	10/22/2021	2011	RET ABN	UG-SERVICE
41528292	GRET	SVC	4/26/2023	2011	RET ABN	UG-SERVICE
43318492	GRET	SVC	8/12/2024	2011	RET ABN	UG-SERVICE
43615032	GRET	SVC	9/24/2024	2011	RET ABN	UG-SERVICE
43151847	GRET	SVC	6/10/2024	2011	RET ABN	UG-SERVICE
41528622	GRET	SVC	4/23/2023	2011	RET ABN	UG-SERVICE
42432713	GRET	SVC	12/2/2023	2011	RET ABN	UG-SERVICE
43514600	GRET	SVC	9/4/2024	2011	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41184951	GRET	SVC	1/19/2023	2011	RET ABN	UG-SERVICE
41520909	GRET	SVC	4/14/2023	2011	RET ABN	UG-SERVICE
36037166	GRET	SVC	2/17/2020	2011	RET ABN	UG-SERVICE
43900063	GRET	SVC	12/4/2024	2011	RET ABN	UG-SERVICE
42619515	GRET	SVC	1/29/2024	2011	RET ABN	UG-SERVICE
41528620	GRET	SVC	4/27/2023	2011	RET ABN	UG-SERVICE
41528443	GRET	SVC	4/23/2023	2011	RET ABN	UG-SERVICE
41520910	GRET	SVC	4/14/2023	2011	RET ABN	UG-SERVICE
42370750	GRET	SVC	11/15/2023	2011	RET ABN	UG-SERVICE
36420955	GRET	SVC	6/8/2020	2011	RET ABN	UG-SERVICE
41571943	GRET	SVC	4/26/2023	2011	RET ABN	UG-SERVICE
39402149	GRET	SVC	11/8/2021	2011	RET ABN	UG-SERVICE
41514008	GRET	SVC	4/17/2023	2011	RET ABN	UG-SERVICE
36707975	GRET	SVC	7/30/2020	2011	RET ABN	UG-SERVICE
41520919	GRET	SVC	4/18/2023	2011	RET ABN	UG-SERVICE
42950627	GRET	SVC	4/18/2024	2011	RET ABN	UG-SERVICE
38414555	GRET	SVC	5/4/2021	2011	RET ABN	UG-SERVICE
41440600	GRET	SVC	3/27/2023	2011	RET ABN	UG-SERVICE
38497724	GRET	SVC	5/12/2021	2011	RET ABN	UG-SERVICE
36090333	GRET	SVC	3/5/2020	2011	RET ABN	UG-SERVICE
38240748	GRET	SVC	3/23/2021	2011	RET ABN	UG-SERVICE
40365304	GRET	SVC	6/29/2022	2011	RET ABN	UG-SERVICE
40112218	GRET	SVC	5/5/2022	2012	RET ABN	UG-SERVICE
41207527	GRET	SVC	1/26/2023	2012	RET ABN	UG-SERVICE
40247521	GRET	SVC	6/2/2022	2012	RET ABN	UG-SERVICE
42747783	GRET	SVC	2/16/2024	2012	RET ABN	UG-SERVICE
39435562	GRET	SVC	11/16/2021	2012	RET ABN	UG-SERVICE
41436378	GRET	SVC	3/25/2023	2012	RET ABN	UG-SERVICE
38107359	GRET	SVC	2/8/2021	2012	RET ABN	UG-SERVICE
41787195	GRET	SVC	6/19/2023	2012	RET ABN	UG-SERVICE
41479988	GRET	SVC	4/6/2023	2012	RET ABN	UG-SERVICE
41279860	GRET	SVC	2/12/2023	2012	RET ABN	UG-SERVICE
43749667	GRET	SVC	10/28/2024	2012	RET ABN	UG-SERVICE
42446591	GRET	SVC	12/5/2023	2012	RET ABN	UG-SERVICE
43139671	GRET	SVC	9/19/2024	2012	RET ABN	UG-SERVICE
42911793	GRET	SVC	4/9/2024	2012	RET ABN	UG-SERVICE
40974642	GRET	SVC	11/29/2022	2012	RET ABN	UG-SERVICE
41279354	GRET	SVC	3/8/2023	2012	RET ABN	UG-SERVICE
40137490	GRET	SVC	5/11/2022	2012	RET ABN	UG-SERVICE
42188672	GRET	SVC	10/2/2023	2012	RET ABN	UG-SERVICE
36121539	GRET	SVC	11/5/2020	2012	RET ABN	UG-SERVICE
40870058	GRET	SVC	11/9/2022	2012	RET ABN	UG-SERVICE
42637733	GRET	SVC	1/29/2024	2012	RET ABN	UG-SERVICE
41116474	GRET	SVC	12/29/2022	2012	RET ABN	UG-SERVICE
36112258	GRET	SVC	10/12/2020	2012	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40310333	GRET	SVC	6/13/2022	2012	RET ABN	UG-SERVICE
41279862	GRET	SVC	2/12/2023	2012	RET ABN	UG-SERVICE
40214147	GRET	SVC	5/26/2022	2012	RET ABN	UG-SERVICE
38551598	GRET	SVC	6/2/2021	2012	RET ABN	UG-SERVICE
35928399	GRET	SVC	1/20/2020	2012	RET ABN	UG-SERVICE
36875127	GRET	SVC	9/28/2020	2012	RET ABN	UG-SERVICE
40472871	GRET	SVC	7/20/2022	2012	RET ABN	UG-SERVICE
43883373	GRET	SVC	12/2/2024	2012	RET ABN	UG-SERVICE
36301100	GRET	SVC	5/27/2020	2012	RET ABN	UG-SERVICE
43481131	GRET	SVC	11/22/2024	2012	RET ABN	UG-SERVICE
40802820	GRET	SVC	10/10/2022	2012	RET ABN	UG-SERVICE
42183152	GRET	SVC	10/4/2023	2012	RET ABN	UG-SERVICE
39493267	GRET	SVC	12/6/2021	2012	RET ABN	UG-SERVICE
40864616	GRET	SVC	10/27/2022	2012	RET ABN	UG-SERVICE
43481130	GRET	SVC	11/2/2024	2012	RET ABN	UG-SERVICE
38612023	GRET	SVC	6/11/2021	2012	RET ABN	UG-SERVICE
40516837	GRET	SVC	8/5/2022	2012	RET ABN	UG-SERVICE
41127758	GRET	SVC	1/4/2023	2012	RET ABN	UG-SERVICE
42432669	GRET	SVC	11/29/2023	2012	RET ABN	UG-SERVICE
41279559	GRET	SVC	2/12/2023	2012	RET ABN	UG-SERVICE
40610967	GRET	SVC	8/25/2022	2012	RET ABN	UG-SERVICE
40691272	GRET	SVC	9/15/2022	2012	RET ABN	UG-SERVICE
38612024	GRET	SVC	6/11/2021	2012	RET ABN	UG-SERVICE
40744548	GRET	SVC	9/29/2022	2012	RET ABN	UG-SERVICE
41033839	GRET	SVC	12/8/2022	2012	RET ABN	UG-SERVICE
37919251	GRET	SVC	12/16/2020	2012	RET ABN	UG-SERVICE
37148988	GRET	SVC	11/2/2020	2012	RET ABN	UG-SERVICE
41436442	GRET	SVC	3/25/2023	2012	RET ABN	UG-SERVICE
36915183	GRET	SVC	9/11/2020	2012	RET ABN	UG-SERVICE
38409143	GRET	SVC	4/27/2021	2012	RET ABN	UG-SERVICE
40667760	GRET	SVC	9/23/2022	2012	RET ABN	UG-SERVICE
42837555	GRET	SVC	3/19/2024	2012	RET ABN	UG-SERVICE
36921493	GRET	SVC	9/14/2020	2012	RET ABN	UG-SERVICE
38534040	GRET	SVC	5/23/2021	2012	RET ABN	UG-SERVICE
42014238	GRET	SVC	8/19/2023	2012	RET ABN	UG-SERVICE
43596477	GRET	SVC	9/26/2024	2012	RET ABN	UG-SERVICE
38386356	GRET	SVC	4/18/2021	2012	RET ABN	UG-SERVICE
40609439	GRET	SVC	8/25/2022	2012	RET ABN	UG-SERVICE
40439933	GRET	SVC	7/13/2022	2012	RET ABN	UG-SERVICE
43586149	GRET	SVC	9/24/2024	2012	RET ABN	UG-SERVICE
41971175	GRET	SVC	8/8/2023	2012	RET ABN	UG-SERVICE
40418097	GRET	SVC	7/13/2022	2012	RET ABN	UG-SERVICE
39459228	GRET	SVC	11/22/2021	2012	RET ABN	UG-SERVICE
41183640	GRET	SVC	1/19/2023	2012	RET ABN	UG-SERVICE
40160583	GRET	SVC	6/6/2022	2012	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40360826	GRET	SVC	6/30/2022	2012	RET ABN	UG-SERVICE
41317819	GRET	SVC	3/2/2023	2013	RET ABN	UG-SERVICE
37093462	GRET	SVC	10/29/2020	2013	RET ABN	UG-SERVICE
40360191	GRET	SVC	6/30/2022	2013	RET ABN	UG-SERVICE
41425203	GRET	SVC	3/22/2023	2013	RET ABN	UG-SERVICE
38580713	GRET	SVC	6/9/2021	2013	RET ABN	UG-SERVICE
40880752	GRET	SVC	10/31/2022	2013	RET ABN	UG-SERVICE
41420721	GRET	SVC	3/24/2023	2013	RET ABN	UG-SERVICE
39581521	GRET	SVC	1/15/2022	2013	RET ABN	UG-SERVICE
43053907	GRET	SVC	5/8/2024	2013	RET ABN	UG-SERVICE
37960327	GRET	SVC	1/2/2021	2013	RET ABN	UG-SERVICE
41540776	GRET	SVC	4/20/2023	2013	RET ABN	UG-SERVICE
40813747	GRET	SVC	10/15/2022	2013	RET ABN	UG-SERVICE
43330334	GRET	SVC	7/17/2024	2013	RET ABN	UG-SERVICE
41330769	GRET	SVC	3/3/2023	2013	RET ABN	UG-SERVICE
38463324	GRET	SVC	5/11/2021	2013	RET ABN	UG-SERVICE
42248449	GRET	SVC	10/19/2023	2013	RET ABN	UG-SERVICE
41430964	GRET	SVC	3/29/2023	2013	RET ABN	UG-SERVICE
40359841	GRET	SVC	7/1/2022	2013	RET ABN	UG-SERVICE
41423634	GRET	SVC	3/22/2023	2013	RET ABN	UG-SERVICE
38053528	GRET	SVC	3/20/2021	2013	RET ABN	UG-SERVICE
40860638	GRET	SVC	11/9/2022	2013	RET ABN	UG-SERVICE
41573968	GRET	SVC	5/1/2023	2013	RET ABN	UG-SERVICE
41418704	GRET	SVC	3/22/2023	2013	RET ABN	UG-SERVICE
43481096	GRET	SVC	10/13/2024	2013	RET ABN	UG-SERVICE
40974224	GRET	SVC	11/29/2022	2013	RET ABN	UG-SERVICE
41423359	GRET	SVC	3/21/2023	2013	RET ABN	UG-SERVICE
39453245	GRET	SVC	8/1/2022	2013	RET ABN	UG-SERVICE
41277762	GRET	SVC	2/24/2023	2013	RET ABN	UG-SERVICE
39965045	GRET	SVC	4/5/2022	2013	RET ABN	UG-SERVICE
41423632	GRET	SVC	3/22/2023	2013	RET ABN	UG-SERVICE
40457109	GRET	SVC	7/14/2022	2013	RET ABN	UG-SERVICE
38953988	GRET	SVC	8/15/2021	2013	RET ABN	UG-SERVICE
41425691	GRET	SVC	3/26/2023	2013	RET ABN	UG-SERVICE
43481092	GRET	SVC	10/31/2024	2013	RET ABN	UG-SERVICE
41485311	GRET	SVC	4/14/2023	2013	RET ABN	UG-SERVICE
36834777	GRET	SVC	8/26/2020	2013	RET ABN	UG-SERVICE
41224005	GRET	SVC	2/2/2023	2013	RET ABN	UG-SERVICE
41529147	GRET	SVC	4/18/2023	2013	RET ABN	UG-SERVICE
38143972	GRET	SVC	2/18/2021	2013	RET ABN	UG-SERVICE
40354109	GRET	SVC	6/28/2022	2013	RET ABN	UG-SERVICE
43531082	GRET	SVC	9/16/2024	2013	RET ABN	UG-SERVICE
38330556	GRET	SVC	4/6/2021	2013	RET ABN	UG-SERVICE
38679328	GRET	SVC	7/12/2021	2013	RET ABN	UG-SERVICE
38240751	GRET	SVC	3/23/2021	2013	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41430968	GRET	SVC	3/29/2023	2013	RET ABN	UG-SERVICE
41194463	GRET	SVC	1/23/2023	2013	RET ABN	UG-SERVICE
39903467	GRET	SVC	3/15/2022	2013	RET ABN	UG-SERVICE
40325388	GRET	SVC	6/20/2022	2013	RET ABN	UG-SERVICE
41425201	GRET	SVC	3/22/2023	2013	RET ABN	UG-SERVICE
38749423	GRET	SVC	7/9/2021	2013	RET ABN	UG-SERVICE
41423628	GRET	SVC	3/21/2023	2013	RET ABN	UG-SERVICE
41423357	GRET	SVC	3/22/2023	2013	RET ABN	UG-SERVICE
41425205	GRET	SVC	3/24/2023	2013	RET ABN	UG-SERVICE
43026757	GRET	SVC	5/5/2024	2013	RET ABN	UG-SERVICE
40974647	GRET	SVC	11/29/2022	2013	RET ABN	UG-SERVICE
41277764	GRET	SVC	2/24/2023	2013	RET ABN	UG-SERVICE
41214158	GRET	SVC	12/11/2023	2013	RET ABN	UG-SERVICE
41301399	GRET	SVC	2/20/2023	2013	RET ABN	UG-SERVICE
39354698	GRET	SVC	10/28/2021	2013	RET ABN	UG-SERVICE
38154421	GRET	SVC	2/22/2021	2013	RET ABN	UG-SERVICE
42484242	GRET	SVC	12/14/2023	2013	RET ABN	UG-SERVICE
40850375	GRET	SVC	10/23/2022	2013	RET ABN	UG-SERVICE
36270420	GRET	SVC	4/27/2020	2013	RET ABN	UG-SERVICE
41031318	GRET	SVC	12/10/2022	2013	RET ABN	UG-SERVICE
39453243	GRET	SVC	8/1/2022	2013	RET ABN	UG-SERVICE
41871392	GRET	SVC	7/12/2023	2013	RET ABN	UG-SERVICE
41775028	GRET	SVC	6/21/2023	2013	RET ABN	UG-SERVICE
36106559	GRET	SVC	3/9/2020	2013	RET ABN	UG-SERVICE
43146620	GRET	SVC	6/3/2024	2013	RET ABN	UG-SERVICE
39734316	GRET	SVC	1/27/2022	2013	RET ABN	UG-SERVICE
42526299	GRET	SVC	1/2/2024	2013	RET ABN	UG-SERVICE
42556757	GRET	SVC	1/10/2024	2013	RET ABN	UG-SERVICE
36223775	GRET	SVC	4/23/2020	2013	RET ABN	UG-SERVICE
42789280	GRET	SVC	3/4/2024	2013	RET ABN	UG-SERVICE
41423622	GRET	SVC	3/21/2023	2013	RET ABN	UG-SERVICE
41927480	GRET	SVC	8/1/2023	2013	RET ABN	UG-SERVICE
36170376	GRET	SVC	3/23/2020	2013	RET ABN	UG-SERVICE
40990758	GRET	SVC	11/26/2022	2013	RET ABN	UG-SERVICE
41317244	GRET	SVC	3/4/2023	2013	RET ABN	UG-SERVICE
42169009	GRET	SVC	10/2/2023	2013	RET ABN	UG-SERVICE
41065074	GRET	SVC	12/12/2022	2013	RET ABN	UG-SERVICE
42475083	GRET	SVC	12/9/2023	2013	RET ABN	UG-SERVICE
42502373	GRET	SVC	12/15/2023	2013	RET ABN	UG-SERVICE
40744737	GRET	SVC	9/21/2022	2013	RET ABN	UG-SERVICE
43533814	GRET	SVC	9/16/2024	2013	RET ABN	UG-SERVICE
41482779	GRET	SVC	4/13/2023	2013	RET ABN	UG-SERVICE
39118131	GRET	SVC	9/14/2021	2013	RET ABN	UG-SERVICE
39434873	GRET	SVC	11/18/2021	2013	RET ABN	UG-SERVICE
41036615	GRET	SVC	12/15/2022	2013	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
35926324	GRET	SVC	1/17/2020	2013	RET ABN	UG-SERVICE
40360387	GRET	SVC	6/30/2022	2013	RET ABN	UG-SERVICE
40949360	GRET	SVC	11/19/2022	2013	RET ABN	UG-SERVICE
38064547	GRET	SVC	1/27/2021	2013	RET ABN	UG-SERVICE
41420301	GRET	SVC	3/24/2023	2013	RET ABN	UG-SERVICE
39827667	GRET	SVC	3/8/2022	2013	RET ABN	UG-SERVICE
40850368	GRET	SVC	10/23/2022	2013	RET ABN	UG-SERVICE
40681869	GRET	SVC	9/14/2022	2013	RET ABN	UG-SERVICE
38194542	GRET	SVC	3/10/2021	2013	RET ABN	UG-SERVICE
41418844	GRET	SVC	3/22/2023	2013	RET ABN	UG-SERVICE
41423925	GRET	SVC	3/20/2023	2013	RET ABN	UG-SERVICE
39899440	GRET	SVC	3/15/2022	2013	RET ABN	UG-SERVICE
36902011	GRET	SVC	9/8/2020	2013	RET ABN	UG-SERVICE
41273859	GRET	SVC	3/16/2023	2013	RET ABN	UG-SERVICE
43341295	GRET	SVC	7/29/2024	2013	RET ABN	UG-SERVICE
36984582	GRET	SVC	9/24/2020	2013	RET ABN	UG-SERVICE
41317494	GRET	SVC	3/3/2023	2013	RET ABN	UG-SERVICE
41846824	GRET	SVC	7/13/2023	2013	RET ABN	UG-SERVICE
43480652	GRET	SVC	10/6/2024	2013	RET ABN	UG-SERVICE
42226860	GRET	SVC	10/18/2023	2013	RET ABN	UG-SERVICE
41330770	GRET	SVC	3/3/2023	2013	RET ABN	UG-SERVICE
36200626	GRET	SVC	4/22/2020	2013	RET ABN	UG-SERVICE
39453241	GRET	SVC	8/1/2022	2013	RET ABN	UG-SERVICE
39118126	GRET	SVC	9/14/2021	2013	RET ABN	UG-SERVICE
40359850	GRET	SVC	6/30/2022	2013	RET ABN	UG-SERVICE
40400416	GRET	SVC	7/11/2022	2013	RET ABN	UG-SERVICE
38608321	GRET	SVC	6/10/2021	2013	RET ABN	UG-SERVICE
36974527	GRET	SVC	9/22/2020	2013	RET ABN	UG-SERVICE
41425210	GRET	SVC	3/24/2023	2013	RET ABN	UG-SERVICE
38745160	GRET	SVC	7/20/2021	2013	RET ABN	UG-SERVICE
41483270	GRET	SVC	4/12/2023	2013	RET ABN	UG-SERVICE
41428824	GRET	SVC	3/27/2023	2013	RET ABN	UG-SERVICE
40324313	GRET	SVC	6/20/2022	2013	RET ABN	UG-SERVICE
40955979	GRET	SVC	12/5/2022	2013	RET ABN	UG-SERVICE
42185202	GRET	SVC	10/2/2023	2013	RET ABN	UG-SERVICE
42921977	GRET	SVC	4/15/2024	2013	RET ABN	UG-SERVICE
41427493	GRET	SVC	3/28/2023	2013	RET ABN	UG-SERVICE
41423932	GRET	SVC	3/21/2023	2013	RET ABN	UG-SERVICE
42182406	GRET	SVC	10/11/2023	2013	RET ABN	UG-SERVICE
43481094	GRET	SVC	10/13/2024	2013	RET ABN	UG-SERVICE
40744891	GRET	SVC	9/21/2022	2013	RET ABN	UG-SERVICE
36995577	GRET	SVC	9/28/2020	2013	RET ABN	UG-SERVICE
42910239	GRET	SVC	4/8/2024	2013	RET ABN	UG-SERVICE
37024316	GRET	SVC	10/30/2020	2013	RET ABN	UG-SERVICE
38708694	GRET	SVC	7/7/2021	2013	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
38934445	GRET	SVC	9/15/2021	2013	RET ABN	UG-SERVICE
42981231	GRET	SVC	4/29/2024	2013	RET ABN	UG-SERVICE
43330439	GRET	SVC	7/3/2024	2013	RET ABN	UG-SERVICE
40659934	GRET	SVC	10/21/2022	2013	RET ABN	UG-SERVICE
43957371	GRET	SVC	12/16/2024	2013	RET ABN	UG-SERVICE
43480654	GRET	SVC	10/6/2024	2013	RET ABN	UG-SERVICE
42796609	GRET	SVC	3/13/2024	2013	RET ABN	UG-SERVICE
40849836	GRET	SVC	10/23/2022	2013	RET ABN	UG-SERVICE
38344248	GRET	SVC	4/12/2021	2014	RET ABN	UG-SERVICE
42671071	GRET	SVC	2/3/2024	2014	RET ABN	UG-SERVICE
41576474	GRET	SVC	3/21/2023	2014	RET ABN	UG-SERVICE
40487925	GRET	SVC	7/25/2022	2014	RET ABN	UG-SERVICE
40353053	GRET	SVC	6/26/2022	2014	RET ABN	UG-SERVICE
40561839	GRET	SVC	8/18/2022	2014	RET ABN	UG-SERVICE
43318351	GRET	SVC	8/26/2024	2014	RET ABN	UG-SERVICE
40982965	GRET	SVC	11/28/2022	2014	RET ABN	UG-SERVICE
41482811	GRET	SVC	4/14/2023	2014	RET ABN	UG-SERVICE
39674319	GRET	SVC	1/12/2022	2014	RET ABN	UG-SERVICE
36096185	GRET	SVC	6/9/2020	2014	RET ABN	UG-SERVICE
42003636	GRET	SVC	8/16/2023	2014	RET ABN	UG-SERVICE
40468017	GRET	SVC	7/14/2022	2014	RET ABN	UG-SERVICE
43402925	GRET	SVC	8/7/2024	2014	RET ABN	UG-SERVICE
39338926	GRET	SVC	11/5/2021	2014	RET ABN	UG-SERVICE
36314549	GRET	SVC	5/11/2020	2014	RET ABN	UG-SERVICE
40708511	GRET	SVC	9/19/2022	2014	RET ABN	UG-SERVICE
40488329	GRET	SVC	7/28/2022	2014	RET ABN	UG-SERVICE
36838641	GRET	SVC	8/29/2020	2014	RET ABN	UG-SERVICE
36164864	GRET	SVC	3/25/2020	2014	RET ABN	UG-SERVICE
41791692	GRET	SVC	6/27/2023	2014	RET ABN	UG-SERVICE
38953221	GRET	SVC	8/23/2021	2014	RET ABN	UG-SERVICE
40492810	GRET	SVC	7/28/2022	2014	RET ABN	UG-SERVICE
38059756	GRET	SVC	1/27/2021	2014	RET ABN	UG-SERVICE
41674280	GRET	SVC	5/22/2023	2014	RET ABN	UG-SERVICE
40983621	GRET	SVC	11/28/2022	2014	RET ABN	UG-SERVICE
43318167	GRET	SVC	8/14/2024	2014	RET ABN	UG-SERVICE
39853612	GRET	SVC	3/8/2022	2014	RET ABN	UG-SERVICE
41513818	GRET	SVC	4/17/2023	2014	RET ABN	UG-SERVICE
36096181	GRET	SVC	6/9/2020	2014	RET ABN	UG-SERVICE
36058957	GRET	SVC	2/22/2020	2014	RET ABN	UG-SERVICE
43506828	GRET	SVC	10/4/2024	2014	RET ABN	UG-SERVICE
36366545	GRET	SVC	5/27/2020	2014	RET ABN	UG-SERVICE
36401305	GRET	SVC	5/31/2020	2014	RET ABN	UG-SERVICE
38359928	GRET	SVC	4/12/2021	2014	RET ABN	UG-SERVICE
41472671	GRET	SVC	4/10/2023	2014	RET ABN	UG-SERVICE
42057086	GRET	SVC	8/30/2023	2014	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42036565	GRET	SVC	8/30/2023	2014	RET ABN	UG-SERVICE
41334615	GRET	SVC	3/6/2023	2014	RET ABN	UG-SERVICE
37901089	GRET	SVC	12/11/2020	2014	RET ABN	UG-SERVICE
41860704	GRET	SVC	7/10/2023	2014	RET ABN	UG-SERVICE
43814800	GRET	SVC	11/15/2024	2014	RET ABN	UG-SERVICE
41508049	GRET	SVC	4/23/2023	2014	RET ABN	UG-SERVICE
41174819	GRET	SVC	1/18/2023	2014	RET ABN	UG-SERVICE
35663480	GRET	SVC	2/5/2020	2014	RET ABN	UG-SERVICE
42468689	GRET	SVC	12/13/2023	2014	RET ABN	UG-SERVICE
41497872	GRET	SVC	4/24/2023	2014	RET ABN	UG-SERVICE
40611930	GRET	SVC	8/21/2022	2014	RET ABN	UG-SERVICE
35663482	GRET	SVC	2/5/2020	2014	RET ABN	UG-SERVICE
40473671	GRET	SVC	7/26/2022	2014	RET ABN	UG-SERVICE
36152899	GRET	SVC	3/17/2020	2014	RET ABN	UG-SERVICE
37148982	GRET	SVC	11/2/2020	2014	RET ABN	UG-SERVICE
38959229	GRET	SVC	10/8/2021	2014	RET ABN	UG-SERVICE
36095742	GRET	SVC	3/7/2020	2014	RET ABN	UG-SERVICE
41031826	GRET	SVC	12/9/2022	2014	RET ABN	UG-SERVICE
41483271	GRET	SVC	4/12/2023	2014	RET ABN	UG-SERVICE
38220966	GRET	SVC	3/14/2021	2014	RET ABN	UG-SERVICE
38059752	GRET	SVC	1/25/2021	2014	RET ABN	UG-SERVICE
41938001	GRET	SVC	8/2/2023	2014	RET ABN	UG-SERVICE
41485312	GRET	SVC	4/19/2023	2014	RET ABN	UG-SERVICE
41584132	GRET	SVC	5/2/2023	2014	RET ABN	UG-SERVICE
39713737	GRET	SVC	1/25/2022	2014	RET ABN	UG-SERVICE
39424443	GRET	SVC	11/16/2021	2014	RET ABN	UG-SERVICE
39264072	GRET	SVC	10/6/2021	2014	RET ABN	UG-SERVICE
41508041	GRET	SVC	4/23/2023	2014	RET ABN	UG-SERVICE
43279916	GRET	SVC	11/27/2024	2014	RET ABN	UG-SERVICE
43953977	GRET	SVC	12/21/2024	2014	RET ABN	UG-SERVICE
38241888	GRET	SVC	3/18/2021	2014	RET ABN	UG-SERVICE
40105476	GRET	SVC	5/3/2022	2014	RET ABN	UG-SERVICE
40561707	GRET	SVC	8/12/2022	2014	RET ABN	UG-SERVICE
40090194	GRET	SVC	5/7/2022	2014	RET ABN	UG-SERVICE
41182819	GRET	SVC	1/20/2023	2014	RET ABN	UG-SERVICE
39776960	GRET	SVC	2/9/2022	2014	RET ABN	UG-SERVICE
40360820	GRET	SVC	6/27/2022	2014	RET ABN	UG-SERVICE
40561718	GRET	SVC	8/18/2022	2014	RET ABN	UG-SERVICE
40468018	GRET	SVC	7/15/2022	2014	RET ABN	UG-SERVICE
41497879	GRET	SVC	4/21/2023	2014	RET ABN	UG-SERVICE
40487933	GRET	SVC	7/26/2022	2014	RET ABN	UG-SERVICE
38397761	GRET	SVC	4/20/2021	2014	RET ABN	UG-SERVICE
41516369	GRET	SVC	4/24/2023	2014	RET ABN	UG-SERVICE
41514328	GRET	SVC	4/15/2023	2014	RET ABN	UG-SERVICE
43330432	GRET	SVC	7/17/2024	2014	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
42036111	GRET	SVC	8/18/2023	2014	RET ABN	UG-SERVICE
36919391	GRET	SVC	9/17/2020	2014	RET ABN	UG-SERVICE
41485316	GRET	SVC	4/13/2023	2014	RET ABN	UG-SERVICE
38536241	GRET	SVC	5/27/2021	2014	RET ABN	UG-SERVICE
41723280	GRET	SVC	6/6/2023	2014	RET ABN	UG-SERVICE
41497637	GRET	SVC	4/12/2023	2014	RET ABN	UG-SERVICE
40685319	GRET	SVC	9/12/2022	2014	RET ABN	UG-SERVICE
40493086	GRET	SVC	7/28/2022	2014	RET ABN	UG-SERVICE
40879395	GRET	SVC	11/11/2022	2014	RET ABN	UG-SERVICE
38785519	GRET	SVC	7/16/2021	2014	RET ABN	UG-SERVICE
41146281	GRET	SVC	2/4/2023	2014	RET ABN	UG-SERVICE
41173975	GRET	SVC	1/18/2023	2014	RET ABN	UG-SERVICE
42973877	GRET	SVC	4/21/2024	2014	RET ABN	UG-SERVICE
41051915	GRET	SVC	1/12/2023	2014	RET ABN	UG-SERVICE
43115135	GRET	SVC	5/28/2024	2014	RET ABN	UG-SERVICE
43703182	GRET	SVC	10/17/2024	2014	RET ABN	UG-SERVICE
36472178	GRET	SVC	6/22/2020	2014	RET ABN	UG-SERVICE
39996609	GRET	SVC	4/16/2022	2014	RET ABN	UG-SERVICE
40500330	GRET	SVC	8/10/2022	2014	RET ABN	UG-SERVICE
41223070	GRET	SVC	1/28/2023	2014	RET ABN	UG-SERVICE
40303323	GRET	SVC	6/14/2022	2014	RET ABN	UG-SERVICE
43505782	GRET	SVC	9/10/2024	2014	RET ABN	UG-SERVICE
38178559	GRET	SVC	3/2/2021	2014	RET ABN	UG-SERVICE
40113467	GRET	SVC	5/11/2022	2014	RET ABN	UG-SERVICE
36153333	GRET	SVC	3/14/2020	2014	RET ABN	UG-SERVICE
38097060	GRET	SVC	9/2/2021	2014	RET ABN	UG-SERVICE
43974003	GRET	SVC	12/28/2024	2014	RET ABN	UG-SERVICE
36867567	GRET	SVC	8/29/2020	2014	RET ABN	UG-SERVICE
37113291	GRET	SVC	10/21/2020	2014	RET ABN	UG-SERVICE
40573500	GRET	SVC	8/18/2022	2014	RET ABN	UG-SERVICE
43610676	GRET	SVC	10/10/2024	2014	RET ABN	UG-SERVICE
43010357	GRET	SVC	4/28/2024	2014	RET ABN	UG-SERVICE
40513296	GRET	SVC	8/10/2022	2014	RET ABN	UG-SERVICE
42183130	GRET	SVC	10/3/2023	2014	RET ABN	UG-SERVICE
40762241	GRET	SVC	10/3/2022	2014	RET ABN	UG-SERVICE
40782678	GRET	SVC	10/6/2022	2014	RET ABN	UG-SERVICE
39801066	GRET	SVC	2/12/2022	2014	RET ABN	UG-SERVICE
42487738	GRET	SVC	7/18/2024	2014	RET ABN	UG-SERVICE
39280846	GRET	SVC	10/12/2021	2014	RET ABN	UG-SERVICE
40750114	GRET	SVC	9/29/2022	2014	RET ABN	UG-SERVICE
42565080	GRET	SVC	1/6/2024	2014	RET ABN	UG-SERVICE
40558508	GRET	SVC	8/12/2022	2014	RET ABN	UG-SERVICE
41480832	GRET	SVC	4/8/2023	2014	RET ABN	UG-SERVICE
36156980	GRET	SVC	5/4/2020	2014	RET ABN	UG-SERVICE
40513444	GRET	SVC	8/10/2022	2014	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40493091	GRET	SVC	7/28/2022	2014	RET ABN	UG-SERVICE
40487932	GRET	SVC	7/20/2022	2014	RET ABN	UG-SERVICE
39970252	GRET	SVC	4/5/2022	2014	RET ABN	UG-SERVICE
42691183	GRET	SVC	2/13/2024	2014	RET ABN	UG-SERVICE
41414816	GRET	SVC	3/20/2023	2014	RET ABN	UG-SERVICE
40468015	GRET	SVC	7/15/2022	2014	RET ABN	UG-SERVICE
40487105	GRET	SVC	7/23/2022	2014	RET ABN	UG-SERVICE
40890259	GRET	SVC	11/21/2022	2014	RET ABN	UG-SERVICE
38179283	GRET	SVC	3/1/2021	2014	RET ABN	UG-SERVICE
40988639	GRET	SVC	1/6/2023	2014	RET ABN	UG-SERVICE
41808563	GRET	SVC	6/22/2023	2014	RET ABN	UG-SERVICE
38711101	GRET	SVC	7/7/2021	2014	RET ABN	UG-SERVICE
40275012	GRET	SVC	6/21/2022	2014	RET ABN	UG-SERVICE
42975502	GRET	SVC	5/1/2024	2014	RET ABN	UG-SERVICE
38429030	GRET	SVC	6/16/2021	2015	RET ABN	UG-SERVICE
40316317	GRET	SVC	7/5/2022	2015	RET ABN	UG-SERVICE
43521336	GRET	SVC	9/10/2024	2015	RET ABN	UG-SERVICE
43600865	GRET	SVC	9/23/2024	2015	RET ABN	UG-SERVICE
40371592	GRET	SVC	7/6/2022	2015	RET ABN	UG-SERVICE
39876680	GRET	SVC	3/7/2022	2015	RET ABN	UG-SERVICE
43480996	GRET	SVC	11/1/2024	2015	RET ABN	UG-SERVICE
41482056	GRET	SVC	3/29/2023	2015	RET ABN	UG-SERVICE
43480934	GRET	SVC	10/5/2024	2015	RET ABN	UG-SERVICE
41483267	GRET	SVC	4/13/2023	2015	RET ABN	UG-SERVICE
42560256	GRET	SVC	1/8/2024	2015	RET ABN	UG-SERVICE
41064671	GRET	SVC	12/15/2022	2015	RET ABN	UG-SERVICE
40395632	GRET	SVC	7/7/2022	2015	RET ABN	UG-SERVICE
40406164	GRET	SVC	7/12/2022	2015	RET ABN	UG-SERVICE
41064583	GRET	SVC	12/16/2022	2015	RET ABN	UG-SERVICE
41117387	GRET	SVC	1/9/2023	2015	RET ABN	UG-SERVICE
39875677	GRET	SVC	3/9/2022	2015	RET ABN	UG-SERVICE
42247462	GRET	SVC	11/10/2023	2015	RET ABN	UG-SERVICE
41036614	GRET	SVC	12/10/2022	2015	RET ABN	UG-SERVICE
35924508	GRET	SVC	1/23/2020	2015	RET ABN	UG-SERVICE
41821844	GRET	SVC	7/1/2023	2015	RET ABN	UG-SERVICE
38665719	GRET	SVC	8/2/2021	2015	RET ABN	UG-SERVICE
38160999	GRET	SVC	2/22/2021	2015	RET ABN	UG-SERVICE
40359847	GRET	SVC	6/28/2022	2015	RET ABN	UG-SERVICE
39710753	GRET	SVC	1/26/2022	2015	RET ABN	UG-SERVICE
42524203	GRET	SVC	1/5/2024	2015	RET ABN	UG-SERVICE
41483028	GRET	SVC	4/14/2023	2015	RET ABN	UG-SERVICE
42937515	GRET	SVC	4/15/2024	2015	RET ABN	UG-SERVICE
40360823	GRET	SVC	6/26/2022	2015	RET ABN	UG-SERVICE
40612350	GRET	SVC	8/23/2022	2015	RET ABN	UG-SERVICE
38778278	GRET	SVC	7/15/2021	2015	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43529801	GRET	SVC	12/12/2024	2015	RET ABN	UG-SERVICE
38200830	GRET	SVC	3/15/2021	2015	RET ABN	UG-SERVICE
41064590	GRET	SVC	12/8/2022	2015	RET ABN	UG-SERVICE
37123589	GRET	SVC	10/28/2020	2015	RET ABN	UG-SERVICE
40352829	GRET	SVC	6/26/2022	2015	RET ABN	UG-SERVICE
39358682	GRET	SVC	10/26/2021	2015	RET ABN	UG-SERVICE
41117038	GRET	SVC	2/8/2023	2015	RET ABN	UG-SERVICE
36349905	GRET	SVC	5/27/2020	2015	RET ABN	UG-SERVICE
41106886	GRET	SVC	12/27/2022	2015	RET ABN	UG-SERVICE
35924321	GRET	SVC	1/16/2020	2015	RET ABN	UG-SERVICE
42004793	GRET	SVC	10/11/2023	2015	RET ABN	UG-SERVICE
39996625	GRET	SVC	4/11/2022	2015	RET ABN	UG-SERVICE
42520520	GRET	SVC	12/29/2023	2015	RET ABN	UG-SERVICE
39318771	GRET	SVC	10/27/2021	2015	RET ABN	UG-SERVICE
43480933	GRET	SVC	10/5/2024	2015	RET ABN	UG-SERVICE
39257539	GRET	SVC	11/10/2021	2015	RET ABN	UG-SERVICE
41253456	GRET	SVC	2/6/2023	2015	RET ABN	UG-SERVICE
41485313	GRET	SVC	4/20/2023	2015	RET ABN	UG-SERVICE
43717837	GRET	SVC	10/19/2024	2015	RET ABN	UG-SERVICE
43866221	GRET	SVC	12/16/2024	2015	RET ABN	UG-SERVICE
43618891	GRET	SVC	9/21/2024	2015	RET ABN	UG-SERVICE
42570263	GRET	SVC	2/20/2024	2015	RET ABN	UG-SERVICE
39768304	GRET	SVC	2/7/2022	2015	RET ABN	UG-SERVICE
41479075	GRET	SVC	4/10/2023	2015	RET ABN	UG-SERVICE
39950430	GRET	SVC	3/31/2022	2015	RET ABN	UG-SERVICE
41585804	GRET	SVC	4/30/2023	2015	RET ABN	UG-SERVICE
41508053	GRET	SVC	4/17/2023	2015	RET ABN	UG-SERVICE
41277501	GRET	SVC	2/24/2023	2015	RET ABN	UG-SERVICE
43480995	GRET	SVC	11/1/2024	2015	RET ABN	UG-SERVICE
41485317	GRET	SVC	4/14/2023	2015	RET ABN	UG-SERVICE
42006927	GRET	SVC	8/10/2023	2015	RET ABN	UG-SERVICE
41482806	GRET	SVC	4/4/2023	2015	RET ABN	UG-SERVICE
42281589	GRET	SVC	10/22/2023	2015	RET ABN	UG-SERVICE
38456261	GRET	SVC	5/4/2021	2015	RET ABN	UG-SERVICE
43506883	GRET	SVC	9/23/2024	2015	RET ABN	UG-SERVICE
42253894	GRET	SVC	10/20/2023	2015	RET ABN	UG-SERVICE
41364435	GRET	SVC	3/13/2023	2015	RET ABN	UG-SERVICE
41064593	GRET	SVC	12/8/2022	2015	RET ABN	UG-SERVICE
41016200	GRET	SVC	12/13/2022	2015	RET ABN	UG-SERVICE
40384604	GRET	SVC	6/24/2022	2015	RET ABN	UG-SERVICE
36366078	GRET	SVC	8/24/2020	2015	RET ABN	UG-SERVICE
39869439	GRET	SVC	3/10/2022	2015	RET ABN	UG-SERVICE
41508055	GRET	SVC	4/17/2023	2015	RET ABN	UG-SERVICE
41223587	GRET	SVC	2/15/2023	2015	RET ABN	UG-SERVICE
36751508	GRET	SVC	8/11/2020	2015	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41483035	GRET	SVC	4/14/2023	2015	RET ABN	UG-SERVICE
37896188	GRET	SVC	12/8/2020	2015	RET ABN	UG-SERVICE
42328558	GRET	SVC	11/7/2023	2015	RET ABN	UG-SERVICE
41016203	GRET	SVC	12/13/2022	2015	RET ABN	UG-SERVICE
41226272	GRET	SVC	1/28/2023	2015	RET ABN	UG-SERVICE
41032258	GRET	SVC	12/4/2022	2015	RET ABN	UG-SERVICE
41498364	GRET	SVC	4/12/2023	2015	RET ABN	UG-SERVICE
38200828	GRET	SVC	3/17/2021	2015	RET ABN	UG-SERVICE
43318355	GRET	SVC	8/6/2024	2015	RET ABN	UG-SERVICE
38416177	GRET	SVC	4/29/2021	2015	RET ABN	UG-SERVICE
40291546	GRET	SVC	6/13/2022	2015	RET ABN	UG-SERVICE
41016206	GRET	SVC	12/13/2022	2015	RET ABN	UG-SERVICE
41032543	GRET	SVC	12/4/2022	2015	RET ABN	UG-SERVICE
37880365	GRET	SVC	12/8/2020	2015	RET ABN	UG-SERVICE
42263863	GRET	SVC	10/23/2023	2015	RET ABN	UG-SERVICE
43707637	GRET	SVC	10/28/2024	2015	RET ABN	UG-SERVICE
41937753	GRET	SVC	7/24/2023	2015	RET ABN	UG-SERVICE
43224594	GRET	SVC	6/26/2024	2015	RET ABN	UG-SERVICE
41128151	GRET	SVC	12/31/2022	2015	RET ABN	UG-SERVICE
35865601	GRET	SVC	1/7/2020	2015	RET ABN	UG-SERVICE
41273578	GRET	SVC	2/16/2023	2015	RET ABN	UG-SERVICE
41032250	GRET	SVC	12/6/2022	2015	RET ABN	UG-SERVICE
40395522	GRET	SVC	7/6/2022	2015	RET ABN	UG-SERVICE
36286881	GRET	SVC	6/13/2020	2015	RET ABN	UG-SERVICE
43250929	GRET	SVC	6/29/2024	2015	RET ABN	UG-SERVICE
40593818	GRET	SVC	8/22/2022	2015	RET ABN	UG-SERVICE
43379780	GRET	SVC	8/1/2024	2015	RET ABN	UG-SERVICE
41274837	GRET	SVC	2/15/2023	2015	RET ABN	UG-SERVICE
41106618	GRET	SVC	12/28/2022	2015	RET ABN	UG-SERVICE
37903754	GRET	SVC	12/16/2020	2015	RET ABN	UG-SERVICE
40578571	GRET	SVC	8/16/2022	2015	RET ABN	UG-SERVICE
41114622	GRET	SVC	12/29/2022	2015	RET ABN	UG-SERVICE
36675999	GRET	SVC	7/28/2020	2015	RET ABN	UG-SERVICE
41036613	GRET	SVC	12/10/2022	2015	RET ABN	UG-SERVICE
38200825	GRET	SVC	3/10/2021	2015	RET ABN	UG-SERVICE
42784177	GRET	SVC	3/5/2024	2015	RET ABN	UG-SERVICE
37045736	GRET	SVC	10/21/2020	2015	RET ABN	UG-SERVICE
41482801	GRET	SVC	4/4/2023	2015	RET ABN	UG-SERVICE
41082582	GRET	SVC	12/19/2022	2015	RET ABN	UG-SERVICE
41572132	GRET	SVC	5/6/2023	2015	RET ABN	UG-SERVICE
41721648	GRET	SVC	6/6/2023	2015	RET ABN	UG-SERVICE
41032549	GRET	SVC	12/16/2022	2015	RET ABN	UG-SERVICE
43207843	GRET	SVC	6/22/2024	2015	RET ABN	UG-SERVICE
39394745	GRET	SVC	11/12/2021	2015	RET ABN	UG-SERVICE
41128156	GRET	SVC	12/31/2022	2015	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41064594	GRET	SVC	12/13/2022	2015	RET ABN	UG-SERVICE
41771847	GRET	SVC	6/27/2023	2016	RET ABN	UG-SERVICE
40216937	GRET	SVC	6/5/2022	2016	RET ABN	UG-SERVICE
41768170	GRET	SVC	6/17/2023	2016	RET ABN	UG-SERVICE
42745597	GRET	SVC	2/19/2024	2016	RET ABN	UG-SERVICE
41187062	GRET	SVC	1/18/2023	2016	RET ABN	UG-SERVICE
40644721	GRET	SVC	9/16/2022	2016	RET ABN	UG-SERVICE
36818926	GRET	SVC	9/4/2020	2016	RET ABN	UG-SERVICE
37013965	GRET	SVC	10/14/2020	2016	RET ABN	UG-SERVICE
43329965	GRET	SVC	7/18/2024	2016	RET ABN	UG-SERVICE
41284192	GRET	SVC	2/21/2023	2016	RET ABN	UG-SERVICE
35956609	GRET	SVC	1/27/2020	2016	RET ABN	UG-SERVICE
35929651	GRET	SVC	1/23/2020	2016	RET ABN	UG-SERVICE
42512725	GRET	SVC	12/26/2023	2016	RET ABN	UG-SERVICE
38635511	GRET	SVC	6/21/2021	2016	RET ABN	UG-SERVICE
42276953	GRET	SVC	10/25/2023	2016	RET ABN	UG-SERVICE
43170486	GRET	SVC	6/17/2024	2016	RET ABN	UG-SERVICE
41690367	GRET	SVC	5/30/2023	2016	RET ABN	UG-SERVICE
40846767	GRET	SVC	10/29/2022	2016	RET ABN	UG-SERVICE
37256532	GRET	SVC	11/9/2020	2016	RET ABN	UG-SERVICE
37064079	GRET	SVC	11/16/2020	2016	RET ABN	UG-SERVICE
36152449	GRET	SVC	3/19/2020	2016	RET ABN	UG-SERVICE
38869778	GRET	SVC	8/5/2021	2016	RET ABN	UG-SERVICE
40555890	GRET	SVC	8/25/2022	2016	RET ABN	UG-SERVICE
41568589	GRET	SVC	4/27/2023	2016	RET ABN	UG-SERVICE
36371110	GRET	SVC	6/19/2020	2016	RET ABN	UG-SERVICE
41918683	GRET	SVC	7/25/2023	2016	RET ABN	UG-SERVICE
43169821	GRET	SVC	6/10/2024	2016	RET ABN	UG-SERVICE
36643846	GRET	SVC	7/20/2020	2016	RET ABN	UG-SERVICE
41284197	GRET	SVC	2/15/2023	2016	RET ABN	UG-SERVICE
36834291	GRET	SVC	8/26/2020	2016	RET ABN	UG-SERVICE
40779653	GRET	SVC	10/26/2022	2016	RET ABN	UG-SERVICE
39613255	GRET	SVC	12/29/2021	2016	RET ABN	UG-SERVICE
42744596	GRET	SVC	2/19/2024	2016	RET ABN	UG-SERVICE
36596483	GRET	SVC	8/12/2020	2016	RET ABN	UG-SERVICE
43071571	GRET	SVC	5/17/2024	2016	RET ABN	UG-SERVICE
40691986	GRET	SVC	9/13/2022	2016	RET ABN	UG-SERVICE
42226914	GRET	SVC	10/16/2023	2016	RET ABN	UG-SERVICE
41284198	GRET	SVC	2/14/2023	2016	RET ABN	UG-SERVICE
43013381	GRET	SVC	5/4/2024	2016	RET ABN	UG-SERVICE
35953732	GRET	SVC	1/27/2020	2016	RET ABN	UG-SERVICE
36948624	GRET	SVC	9/18/2020	2016	RET ABN	UG-SERVICE
41568561	GRET	SVC	4/27/2023	2016	RET ABN	UG-SERVICE
39257781	GRET	SVC	10/12/2021	2016	RET ABN	UG-SERVICE
43831245	GRET	SVC	11/26/2024	2016	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43741075	GRET	SVC	10/28/2024	2016	RET ABN	UG-SERVICE
41673901	GRET	SVC	5/22/2023	2016	RET ABN	UG-SERVICE
41405833	GRET	SVC	3/20/2023	2016	RET ABN	UG-SERVICE
40230340	GRET	SVC	5/31/2022	2016	RET ABN	UG-SERVICE
43526642	GRET	SVC	9/5/2024	2016	RET ABN	UG-SERVICE
41279556	GRET	SVC	2/12/2023	2016	RET ABN	UG-SERVICE
36021124	GRET	SVC	2/12/2020	2016	RET ABN	UG-SERVICE
40780619	GRET	SVC	10/10/2022	2016	RET ABN	UG-SERVICE
42975777	GRET	SVC	6/3/2024	2016	RET ABN	UG-SERVICE
38092844	GRET	SVC	2/4/2021	2016	RET ABN	UG-SERVICE
39668880	GRET	SVC	1/10/2022	2016	RET ABN	UG-SERVICE
43225267	GRET	SVC	6/26/2024	2016	RET ABN	UG-SERVICE
41287538	GRET	SVC	3/18/2023	2016	RET ABN	UG-SERVICE
39773244	GRET	SVC	2/9/2022	2016	RET ABN	UG-SERVICE
38568981	GRET	SVC	6/7/2021	2016	RET ABN	UG-SERVICE
40874774	GRET	SVC	10/29/2022	2016	RET ABN	UG-SERVICE
38200983	GRET	SVC	3/10/2021	2016	RET ABN	UG-SERVICE
36650025	GRET	SVC	7/18/2020	2016	RET ABN	UG-SERVICE
42706729	GRET	SVC	2/13/2024	2016	RET ABN	UG-SERVICE
40558481	GRET	SVC	8/21/2022	2016	RET ABN	UG-SERVICE
41609017	GRET	SVC	5/6/2023	2016	RET ABN	UG-SERVICE
42995589	GRET	SVC	4/30/2024	2016	RET ABN	UG-SERVICE
38941812	GRET	SVC	8/18/2021	2016	RET ABN	UG-SERVICE
41286301	GRET	SVC	3/17/2023	2016	RET ABN	UG-SERVICE
42921106	GRET	SVC	3/30/2024	2016	RET ABN	UG-SERVICE
43345805	GRET	SVC	7/26/2024	2016	RET ABN	UG-SERVICE
40976086	GRET	SVC	11/28/2022	2016	RET ABN	UG-SERVICE
38596272	GRET	SVC	6/8/2021	2016	RET ABN	UG-SERVICE
42788300	GRET	SVC	3/11/2024	2016	RET ABN	UG-SERVICE
43862725	GRET	SVC	11/25/2024	2016	RET ABN	UG-SERVICE
37986309	GRET	SVC	1/5/2021	2016	RET ABN	UG-SERVICE
36682911	GRET	SVC	7/27/2020	2016	RET ABN	UG-SERVICE
41919955	GRET	SVC	8/7/2023	2016	RET ABN	UG-SERVICE
43883122	GRET	SVC	12/9/2024	2016	RET ABN	UG-SERVICE
39149347	GRET	SVC	9/16/2021	2016	RET ABN	UG-SERVICE
39316996	GRET	SVC	10/25/2021	2016	RET ABN	UG-SERVICE
40672066	GRET	SVC	10/1/2022	2016	RET ABN	UG-SERVICE
39249723	GRET	SVC	10/11/2021	2016	RET ABN	UG-SERVICE
39215340	GRET	SVC	11/1/2021	2016	RET ABN	UG-SERVICE
41439586	GRET	SVC	3/27/2023	2016	RET ABN	UG-SERVICE
42707431	GRET	SVC	2/11/2024	2016	RET ABN	UG-SERVICE
36196116	GRET	SVC	4/21/2020	2016	RET ABN	UG-SERVICE
41769393	GRET	SVC	6/17/2023	2016	RET ABN	UG-SERVICE
37896786	GRET	SVC	12/9/2020	2016	RET ABN	UG-SERVICE
39352877	GRET	SVC	10/19/2021	2016	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43822621	GRET	SVC	11/8/2024	2016	RET ABN	UG-SERVICE
40746028	GRET	SVC	9/23/2022	2017	RET ABN	UG-SERVICE
43683503	GRET	SVC	10/14/2024	2017	RET ABN	UG-SERVICE
40375096	GRET	SVC	7/2/2022	2017	RET ABN	UG-SERVICE
43060531	GRET	SVC	5/13/2024	2017	RET ABN	UG-SERVICE
43668851	GRET	SVC	10/8/2024	2017	RET ABN	UG-SERVICE
40499691	GRET	SVC	8/1/2022	2017	RET ABN	UG-SERVICE
41639188	GRET	SVC	5/19/2023	2017	RET ABN	UG-SERVICE
41389385	GRET	SVC	3/13/2023	2017	RET ABN	UG-SERVICE
41283637	GRET	SVC	2/18/2023	2017	RET ABN	UG-SERVICE
39930409	GRET	SVC	3/28/2022	2017	RET ABN	UG-SERVICE
41904186	GRET	SVC	7/25/2023	2017	RET ABN	UG-SERVICE
43364928	GRET	SVC	12/2/2024	2017	RET ABN	UG-SERVICE
43481247	GRET	SVC	11/22/2024	2017	RET ABN	UG-SERVICE
41274584	GRET	SVC	2/13/2023	2017	RET ABN	UG-SERVICE
43752069	GRET	SVC	11/16/2024	2017	RET ABN	UG-SERVICE
40319102	GRET	SVC	6/20/2022	2017	RET ABN	UG-SERVICE
43480992	GRET	SVC	11/10/2024	2017	RET ABN	UG-SERVICE
41803122	GRET	SVC	6/27/2023	2017	RET ABN	UG-SERVICE
38349990	GRET	SVC	4/14/2021	2017	RET ABN	UG-SERVICE
43370930	GRET	SVC	7/30/2024	2017	RET ABN	UG-SERVICE
36602821	GRET	SVC	7/9/2020	2017	RET ABN	UG-SERVICE
36168225	GRET	SVC	3/23/2020	2017	RET ABN	UG-SERVICE
39880011	GRET	SVC	3/14/2022	2017	RET ABN	UG-SERVICE
38222416	GRET	SVC	3/17/2021	2017	RET ABN	UG-SERVICE
39324294	GRET	SVC	10/27/2021	2017	RET ABN	UG-SERVICE
40383953	GRET	SVC	7/5/2022	2017	RET ABN	UG-SERVICE
38067901	GRET	SVC	1/25/2021	2017	RET ABN	UG-SERVICE
40091708	GRET	SVC	5/2/2022	2017	RET ABN	UG-SERVICE
38364543	GRET	SVC	4/14/2021	2017	RET ABN	UG-SERVICE
37115386	GRET	SVC	11/2/2020	2017	RET ABN	UG-SERVICE
43642980	GRET	SVC	10/7/2024	2017	RET ABN	UG-SERVICE
38880692	GRET	SVC	8/6/2021	2017	RET ABN	UG-SERVICE
38526701	GRET	SVC	4/11/2021	2017	RET ABN	UG-SERVICE
41893698	GRET	SVC	7/21/2023	2017	RET ABN	UG-SERVICE
41534326	GRET	SVC	5/8/2023	2017	RET ABN	UG-SERVICE
38174775	GRET	SVC	2/27/2021	2017	RET ABN	UG-SERVICE
42181125	GRET	SVC	10/4/2023	2017	RET ABN	UG-SERVICE
39873510	GRET	SVC	3/15/2022	2017	RET ABN	UG-SERVICE
41484577	GRET	SVC	4/18/2023	2017	RET ABN	UG-SERVICE
43905526	GRET	SVC	12/9/2024	2017	RET ABN	UG-SERVICE
42257455	GRET	SVC	10/23/2023	2017	RET ABN	UG-SERVICE
39878839	GRET	SVC	3/14/2022	2017	RET ABN	UG-SERVICE
42653746	GRET	SVC	2/5/2024	2017	RET ABN	UG-SERVICE
41083717	GRET	SVC	12/20/2022	2017	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41750989	GRET	SVC	6/13/2023	2017	RET ABN	UG-SERVICE
40204785	GRET	SVC	5/23/2022	2017	RET ABN	UG-SERVICE
43957196	GRET	SVC	12/18/2024	2017	RET ABN	UG-SERVICE
39550414	GRET	SVC	12/16/2021	2017	RET ABN	UG-SERVICE
43459323	GRET	SVC	8/19/2024	2017	RET ABN	UG-SERVICE
40878242	GRET	SVC	11/7/2022	2017	RET ABN	UG-SERVICE
43715117	GRET	SVC	10/22/2024	2017	RET ABN	UG-SERVICE
42914394	GRET	SVC	4/11/2024	2017	RET ABN	UG-SERVICE
41175051	GRET	SVC	1/20/2023	2017	RET ABN	UG-SERVICE
41566183	GRET	SVC	4/25/2023	2017	RET ABN	UG-SERVICE
41560897	GRET	SVC	4/20/2023	2017	RET ABN	UG-SERVICE
42222135	GRET	SVC	10/12/2023	2017	RET ABN	UG-SERVICE
39275116	GRET	SVC	10/15/2021	2017	RET ABN	UG-SERVICE
40928808	GRET	SVC	11/15/2022	2017	RET ABN	UG-SERVICE
42939579	GRET	SVC	4/17/2024	2017	RET ABN	UG-SERVICE
42594903	GRET	SVC	1/24/2024	2017	RET ABN	UG-SERVICE
40853685	GRET	SVC	10/24/2022	2017	RET ABN	UG-SERVICE
43219490	GRET	SVC	6/25/2024	2017	RET ABN	UG-SERVICE
43506824	GRET	SVC	10/3/2024	2017	RET ABN	UG-SERVICE
41424768	GRET	SVC	10/18/2023	2017	RET ABN	UG-SERVICE
36486890	GRET	SVC	6/25/2020	2017	RET ABN	UG-SERVICE
41926528	GRET	SVC	7/29/2023	2017	RET ABN	UG-SERVICE
36152268	GRET	SVC	3/16/2020	2017	RET ABN	UG-SERVICE
39713217	GRET	SVC	1/12/2022	2017	RET ABN	UG-SERVICE
36366992	GRET	SVC	5/26/2020	2017	RET ABN	UG-SERVICE
41279548	GRET	SVC	2/12/2023	2017	RET ABN	UG-SERVICE
42907196	GRET	SVC	4/7/2024	2017	RET ABN	UG-SERVICE
41588281	GRET	SVC	5/3/2023	2017	RET ABN	UG-SERVICE
43582912	GRET	SVC	9/18/2024	2017	RET ABN	UG-SERVICE
42762981	GRET	SVC	2/29/2024	2017	RET ABN	UG-SERVICE
42967786	GRET	SVC	4/25/2024	2017	RET ABN	UG-SERVICE
36200532	GRET	SVC	4/23/2020	2017	RET ABN	UG-SERVICE
41955802	GRET	SVC	8/5/2023	2017	RET ABN	UG-SERVICE
39081127	GRET	SVC	9/10/2021	2017	RET ABN	UG-SERVICE
36199243	GRET	SVC	5/14/2020	2017	RET ABN	UG-SERVICE
42277126	GRET	SVC	10/12/2023	2017	RET ABN	UG-SERVICE
43481120	GRET	SVC	10/29/2024	2017	RET ABN	UG-SERVICE
42096936	GRET	SVC	9/12/2023	2017	RET ABN	UG-SERVICE
36347808	GRET	SVC	5/19/2020	2017	RET ABN	UG-SERVICE
41958783	GRET	SVC	8/7/2023	2018	RET ABN	UG-SERVICE
37844120	GRET	SVC	12/1/2020	2018	RET ABN	UG-SERVICE
40092393	GRET	SVC	4/27/2022	2018	RET ABN	UG-SERVICE
38428372	GRET	SVC	4/28/2021	2018	RET ABN	UG-SERVICE
39194846	GRET	SVC	9/27/2021	2018	RET ABN	UG-SERVICE
40035889	GRET	SVC	4/20/2022	2018	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40694162	GRET	SVC	9/15/2022	2018	RET ABN	UG-SERVICE
36598693	GRET	SVC	7/25/2020	2018	RET ABN	UG-SERVICE
38741237	GRET	SVC	7/27/2021	2018	RET ABN	UG-SERVICE
43489146	GRET	SVC	8/26/2024	2018	RET ABN	UG-SERVICE
40860204	GRET	SVC	10/25/2022	2018	RET ABN	UG-SERVICE
36643845	GRET	SVC	7/20/2020	2018	RET ABN	UG-SERVICE
41205724	GRET	SVC	1/27/2023	2018	RET ABN	UG-SERVICE
41286322	GRET	SVC	2/20/2023	2018	RET ABN	UG-SERVICE
36019879	GRET	SVC	2/12/2020	2018	RET ABN	UG-SERVICE
43481045	GRET	SVC	11/1/2024	2018	RET ABN	UG-SERVICE
38312793	GRET	SVC	4/7/2021	2018	RET ABN	UG-SERVICE
43571069	GRET	SVC	9/17/2024	2018	RET ABN	UG-SERVICE
36066842	GRET	SVC	2/28/2020	2018	RET ABN	UG-SERVICE
40782757	GRET	SVC	10/7/2022	2018	RET ABN	UG-SERVICE
43147157	GRET	SVC	6/3/2024	2018	RET ABN	UG-SERVICE
40812314	GRET	SVC	10/30/2022	2018	RET ABN	UG-SERVICE
43058936	GRET	SVC	5/15/2024	2018	RET ABN	UG-SERVICE
42944771	GRET	SVC	4/16/2024	2018	RET ABN	UG-SERVICE
39657980	GRET	SVC	1/30/2022	2018	RET ABN	UG-SERVICE
42906048	GRET	SVC	4/10/2024	2018	RET ABN	UG-SERVICE
43752226	GRET	SVC	11/27/2024	2018	RET ABN	UG-SERVICE
42078595	GRET	SVC	5/9/2023	2018	RET ABN	UG-SERVICE
39242836	GRET	SVC	10/4/2021	2018	RET ABN	UG-SERVICE
39120028	GRET	SVC	9/14/2021	2018	RET ABN	UG-SERVICE
43370808	GRET	SVC	11/4/2024	2018	RET ABN	UG-SERVICE
42470302	GRET	SVC	12/11/2023	2018	RET ABN	UG-SERVICE
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40118393	GRET	SVC	5/4/2022	2018	RET ABN	UG-SERVICE
43023019	GRET	SVC	5/6/2024	2018	RET ABN	UG-SERVICE
38089275	GRET	SVC	2/2/2021	2018	RET ABN	UG-SERVICE
41883655	GRET	SVC	7/15/2023	2018	RET ABN	UG-SERVICE
39484987	GRET	SVC	11/26/2021	2018	RET ABN	UG-SERVICE
43948489	GRET	SVC	12/19/2024	2018	RET ABN	UG-SERVICE
37560374	GRET	SVC	11/5/2020	2018	RET ABN	UG-SERVICE
36914331	GRET	SVC	9/17/2020	2018	RET ABN	UG-SERVICE
40333089	GRET	SVC	6/21/2022	2018	RET ABN	UG-SERVICE
41585923	GRET	SVC	5/2/2023	2018	RET ABN	UG-SERVICE
39776979	GRET	SVC	2/9/2022	2018	RET ABN	UG-SERVICE
40545980	GRET	SVC	1/3/2023	2018	RET ABN	UG-SERVICE
38257670	GRET	SVC	3/20/2021	2018	RET ABN	UG-SERVICE
43861748	GRET	SVC	12/9/2024	2018	RET ABN	UG-SERVICE
40883589	GRET	SVC	11/9/2022	2018	RET ABN	UG-SERVICE
43648281	GRET	SVC	10/22/2024	2018	RET ABN	UG-SERVICE
37358765	GRET	SVC	10/29/2020	2018	RET ABN	UG-SERVICE
40645570	GRET	SVC	8/31/2022	2018	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
36999957	GRET	SVC	10/5/2020	2018	RET ABN	UG-SERVICE
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41699139	GRET	SVC	5/30/2023	2018	RET ABN	UG-SERVICE
42250456	GRET	SVC	10/16/2023	2018	RET ABN	UG-SERVICE
38301277	GRET	SVC	7/30/2021	2018	RET ABN	UG-SERVICE
43330270	GRET	SVC	7/15/2024	2018	RET ABN	UG-SERVICE
43466685	GRET	SVC	9/16/2024	2018	RET ABN	UG-SERVICE
39890608	GRET	SVC	3/28/2022	2018	RET ABN	UG-SERVICE
39266340	GRET	SVC	10/11/2021	2018	RET ABN	UG-SERVICE
41913462	GRET	SVC	7/24/2023	2018	RET ABN	UG-SERVICE
40593804	GRET	SVC	8/16/2022	2018	RET ABN	UG-SERVICE
43654922	GRET	SVC	10/2/2024	2018	RET ABN	UG-SERVICE
40949361	GRET	SVC	12/9/2022	2018	RET ABN	UG-SERVICE
41030771	GRET	SVC	12/7/2022	2018	RET ABN	UG-SERVICE
38706201	GRET	SVC	7/7/2021	2018	RET ABN	UG-SERVICE
43493904	GRET	SVC	9/4/2024	2018	RET ABN	UG-SERVICE
41224142	GRET	SVC	1/28/2023	2018	RET ABN	UG-SERVICE
42177006	GRET	SVC	9/29/2023	2018	RET ABN	UG-SERVICE
38838961	GRET	SVC	7/20/2021	2018	RET ABN	UG-SERVICE
36114268	GRET	SVC	3/11/2020	2018	RET ABN	UG-SERVICE
41669294	GRET	SVC	5/25/2023	2018	RET ABN	UG-SERVICE
43141728	GRET	SVC	6/1/2024	2018	RET ABN	UG-SERVICE
36820287	GRET	SVC	8/25/2020	2018	RET ABN	UG-SERVICE
40062841	GRET	SVC	5/14/2022	2018	RET ABN	UG-SERVICE
36577459	GRET	SVC	7/8/2020	2018	RET ABN	UG-SERVICE
40558804	GRET	SVC	8/11/2022	2018	RET ABN	UG-SERVICE
41612016	GRET	SVC	5/8/2023	2018	RET ABN	UG-SERVICE
36685504	GRET	SVC	7/27/2020	2018	RET ABN	UG-SERVICE
38534654	GRET	SVC	5/27/2021	2018	RET ABN	UG-SERVICE
38397595	GRET	SVC	4/21/2021	2018	RET ABN	UG-SERVICE
41397335	GRET	SVC	3/16/2023	2018	RET ABN	UG-SERVICE
41398471	GRET	SVC	3/14/2023	2018	RET ABN	UG-SERVICE
40506220	GRET	SVC	8/2/2022	2018	RET ABN	UG-SERVICE
39850142	GRET	SVC	3/4/2022	2018	RET ABN	UG-SERVICE
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43519323	GRET	SVC	9/10/2024	2018	RET ABN	UG-SERVICE
41480834	GRET	SVC	4/8/2023	2018	RET ABN	UG-SERVICE
38330664	GRET	SVC	4/6/2021	2018	RET ABN	UG-SERVICE
39996896	GRET	SVC	4/25/2022	2018	RET ABN	UG-SERVICE
36793151	GRET	SVC	8/17/2020	2018	RET ABN	UG-SERVICE
39245797	GRET	SVC	10/6/2021	2018	RET ABN	UG-SERVICE
43669822	GRET	SVC	10/11/2024	2018	RET ABN	UG-SERVICE
41480226	GRET	SVC	4/9/2023	2018	RET ABN	UG-SERVICE
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order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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36916483	GRET	SVC	9/11/2020	2018	RET ABN	UG-SERVICE
41916572	GRET	SVC	8/22/2023	2018	RET ABN	UG-SERVICE
39166343	GRET	SVC	9/29/2021	2018	RET ABN	UG-SERVICE
43654684	GRET	SVC	10/21/2024	2018	RET ABN	UG-SERVICE
42903351	GRET	SVC	4/10/2024	2018	RET ABN	UG-SERVICE
38534655	GRET	SVC	5/24/2021	2018	RET ABN	UG-SERVICE
42409830	GRET	SVC	11/28/2023	2018	RET ABN	UG-SERVICE
42078302	GRET	SVC	9/5/2023	2019	RET ABN	UG-SERVICE
36282719	GRET	SVC	6/15/2020	2019	RET ABN	UG-SERVICE
37739212	GRET	SVC	11/23/2020	2019	RET ABN	UG-SERVICE
38719485	GRET	SVC	7/12/2021	2019	RET ABN	UG-SERVICE
40418554	GRET	SVC	7/13/2022	2019	RET ABN	UG-SERVICE
43676776	GRET	SVC	10/15/2024	2019	RET ABN	UG-SERVICE
36283381	GRET	SVC	6/15/2020	2019	RET ABN	UG-SERVICE
36671815	GRET	SVC	7/24/2020	2019	RET ABN	UG-SERVICE
36192819	GRET	SVC	4/15/2020	2019	RET ABN	UG-SERVICE
36598689	GRET	SVC	7/25/2020	2019	RET ABN	UG-SERVICE
39233803	GRET	SVC	10/15/2021	2019	RET ABN	UG-SERVICE
36282718	GRET	SVC	6/15/2020	2019	RET ABN	UG-SERVICE
42425970	GRET	SVC	11/27/2023	2019	RET ABN	UG-SERVICE
39150591	GRET	SVC	9/20/2021	2019	RET ABN	UG-SERVICE
39892549	GRET	SVC	3/15/2022	2019	RET ABN	UG-SERVICE
42476344	GRET	SVC	12/7/2023	2019	RET ABN	UG-SERVICE
43353626	GRET	SVC	11/4/2024	2019	RET ABN	UG-SERVICE
41334869	GRET	SVC	3/6/2023	2019	RET ABN	UG-SERVICE
43915732	GRET	SVC	12/16/2024	2019	RET ABN	UG-SERVICE
36270018	GRET	SVC	4/28/2020	2019	RET ABN	UG-SERVICE
38361202	GRET	SVC	4/14/2021	2019	RET ABN	UG-SERVICE
43882980	GRET	SVC	11/30/2024	2019	RET ABN	UG-SERVICE
36192180	GRET	SVC	4/24/2020	2019	RET ABN	UG-SERVICE
43218663	GRET	SVC	6/25/2024	2019	RET ABN	UG-SERVICE
40368480	GRET	SVC	6/29/2022	2019	RET ABN	UG-SERVICE
35986290	GRET	SVC	2/4/2020	2019	RET ABN	UG-SERVICE
38514856	GRET	SVC	8/5/2021	2019	RET ABN	UG-SERVICE
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37773047	GRET	SVC	11/24/2020	2019	RET ABN	UG-SERVICE
41402091	GRET	SVC	3/15/2023	2019	RET ABN	UG-SERVICE
39550753	GRET	SVC	12/17/2021	2019	RET ABN	UG-SERVICE
41114425	GRET	SVC	1/7/2023	2019	RET ABN	UG-SERVICE
36760770	GRET	SVC	8/11/2020	2019	RET ABN	UG-SERVICE
40050472	GRET	SVC	4/26/2022	2019	RET ABN	UG-SERVICE
43066566	GRET	SVC	5/20/2024	2019	RET ABN	UG-SERVICE
39233714	GRET	SVC	10/11/2021	2019	RET ABN	UG-SERVICE
37914673	GRET	SVC	12/13/2020	2019	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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36598690	GRET	SVC	7/25/2020	2019	RET ABN	UG-SERVICE
38373952	GRET	SVC	5/3/2021	2019	RET ABN	UG-SERVICE
36740314	GRET	SVC	8/17/2020	2019	RET ABN	UG-SERVICE
36572213	GRET	SVC	6/30/2020	2019	RET ABN	UG-SERVICE
40939061	GRET	SVC	12/6/2022	2019	RET ABN	UG-SERVICE
36837899	GRET	SVC	9/1/2020	2019	RET ABN	UG-SERVICE
38373081	GRET	SVC	4/14/2021	2019	RET ABN	UG-SERVICE
42833098	GRET	SVC	7/22/2024	2019	RET ABN	UG-SERVICE
42166610	GRET	SVC	9/26/2023	2019	RET ABN	UG-SERVICE
43709853	GRET	SVC	10/21/2024	2019	RET ABN	UG-SERVICE
40711628	GRET	SVC	9/18/2022	2019	RET ABN	UG-SERVICE
43318029	GRET	SVC	7/25/2024	2019	RET ABN	UG-SERVICE
39895678	GRET	SVC	3/14/2022	2019	RET ABN	UG-SERVICE
40318183	GRET	SVC	6/22/2022	2019	RET ABN	UG-SERVICE
41401436	GRET	SVC	3/24/2023	2019	RET ABN	UG-SERVICE
36696973	GRET	SVC	7/29/2020	2019	RET ABN	UG-SERVICE
40268707	GRET	SVC	6/7/2022	2019	RET ABN	UG-SERVICE
40607289	GRET	SVC	8/24/2022	2019	RET ABN	UG-SERVICE
41768694	GRET	SVC	6/17/2023	2019	RET ABN	UG-SERVICE
41114388	GRET	SVC	12/28/2022	2019	RET ABN	UG-SERVICE
36833931	GRET	SVC	8/26/2020	2019	RET ABN	UG-SERVICE
36598694	GRET	SVC	7/25/2020	2019	RET ABN	UG-SERVICE
43798465	GRET	SVC	11/9/2024	2019	RET ABN	UG-SERVICE
43345694	GRET	SVC	7/26/2024	2019	RET ABN	UG-SERVICE
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40020074	GRET	SVC	5/23/2022	2019	RET ABN	UG-SERVICE
43480650	GRET	SVC	10/2/2024	2019	RET ABN	UG-SERVICE
38873032	GRET	SVC	8/1/2021	2019	RET ABN	UG-SERVICE
38242133	GRET	SVC	3/16/2021	2019	RET ABN	UG-SERVICE
36283380	GRET	SVC	6/15/2020	2019	RET ABN	UG-SERVICE
39776976	GRET	SVC	2/11/2022	2019	RET ABN	UG-SERVICE
39350824	GRET	SVC	10/28/2021	2019	RET ABN	UG-SERVICE
38865013	GRET	SVC	8/3/2021	2019	RET ABN	UG-SERVICE
42150648	GRET	SVC	9/25/2023	2019	RET ABN	UG-SERVICE
40018465	GRET	SVC	4/16/2022	2019	RET ABN	UG-SERVICE
42184977	GRET	SVC	10/5/2023	2019	RET ABN	UG-SERVICE
42164208	GRET	SVC	11/30/2023	2019	RET ABN	UG-SERVICE
39821358	GRET	SVC	2/21/2022	2019	RET ABN	UG-SERVICE
41649339	GRET	SVC	5/19/2023	2019	RET ABN	UG-SERVICE
38954719	GRET	SVC	8/31/2021	2019	RET ABN	UG-SERVICE
41402227	GRET	SVC	3/15/2023	2019	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
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42837761	GRET	SVC	3/19/2024	2019	RET ABN	UG-SERVICE
43697688	GRET	SVC	10/12/2024	2019	RET ABN	UG-SERVICE
41089225	GRET	SVC	12/22/2022	2019	RET ABN	UG-SERVICE
39020762	GRET	SVC	8/30/2021	2019	RET ABN	UG-SERVICE
38942234	GRET	SVC	8/23/2021	2019	RET ABN	UG-SERVICE
43759459	GRET	SVC	10/29/2024	2019	RET ABN	UG-SERVICE
43481044	GRET	SVC	11/1/2024	2019	RET ABN	UG-SERVICE
41772175	GRET	SVC	6/19/2023	2019	RET ABN	UG-SERVICE
36270003	GRET	SVC	4/29/2020	2019	RET ABN	UG-SERVICE
36627611	GRET	SVC	7/11/2020	2019	RET ABN	UG-SERVICE
40515683	GRET	SVC	8/2/2022	2019	RET ABN	UG-SERVICE
38514348	GRET	SVC	5/24/2021	2019	RET ABN	UG-SERVICE
37944918	GRET	SVC	12/22/2020	2019	RET ABN	UG-SERVICE
41049460	GRET	SVC	2/21/2023	2019	RET ABN	UG-SERVICE
37019195	GRET	SVC	10/6/2020	2019	RET ABN	UG-SERVICE
36734668	GRET	SVC	9/2/2020	2019	RET ABN	UG-SERVICE
39719594	GRET	SVC	1/25/2022	2019	RET ABN	UG-SERVICE
39461568	GRET	SVC	11/22/2021	2019	RET ABN	UG-SERVICE
41286748	GRET	SVC	2/20/2023	2019	RET ABN	UG-SERVICE
39950252	GRET	SVC	3/30/2022	2019	RET ABN	UG-SERVICE
43112291	GRET	SVC	5/26/2024	2020	RET ABN	UG-SERVICE
42392613	GRET	SVC	11/20/2023	2020	RET ABN	UG-SERVICE
42842213	GRET	SVC	3/18/2024	2020	RET ABN	UG-SERVICE
36545679	GRET	SVC	6/30/2020	2020	RET ABN	UG-SERVICE
43281677	GRET	SVC	7/6/2024	2020	RET ABN	UG-SERVICE
40584450	GRET	SVC	8/18/2022	2020	RET ABN	UG-SERVICE
40432776	GRET	SVC	7/13/2022	2020	RET ABN	UG-SERVICE
41389717	GRET	SVC	3/16/2023	2020	RET ABN	UG-SERVICE
41925433	GRET	SVC	7/30/2023	2020	RET ABN	UG-SERVICE
42461810	GRET	SVC	12/9/2023	2020	RET ABN	UG-SERVICE
39671443	GRET	SVC	1/10/2022	2020	RET ABN	UG-SERVICE
40840380	GRET	SVC	10/18/2022	2020	RET ABN	UG-SERVICE
41425425	GRET	SVC	5/1/2023	2020	RET ABN	UG-SERVICE
43496215	GRET	SVC	9/10/2024	2020	RET ABN	UG-SERVICE
38258599	GRET	SVC	3/24/2021	2020	RET ABN	UG-SERVICE
42327735	GRET	SVC	11/3/2023	2020	RET ABN	UG-SERVICE
38461048	GRET	SVC	5/7/2021	2020	RET ABN	UG-SERVICE
43488609	GRET	SVC	9/6/2024	2020	RET ABN	UG-SERVICE
43083117	GRET	SVC	5/22/2024	2020	RET ABN	UG-SERVICE
38852427	GRET	SVC	7/29/2021	2020	RET ABN	UG-SERVICE
43903567	GRET	SVC	12/26/2024	2020	RET ABN	UG-SERVICE
41379500	GRET	SVC	3/14/2023	2020	RET ABN	UG-SERVICE
37809334	GRET	SVC	11/24/2020	2020	RET ABN	UG-SERVICE

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39506088	GRET	SVC	12/7/2021	2020	RET ABN	UG-SERVICE
41833025	GRET	SVC	7/6/2023	2020	RET ABN	UG-SERVICE
43615938	GRET	SVC	9/23/2024	2020	RET ABN	UG-SERVICE
36191044	GRET	SVC	6/27/2020	2020	RET ABN	UG-SERVICE
41018278	GRET	SVC	12/6/2022	2020	RET ABN	UG-SERVICE
42165550	GRET	SVC	9/22/2023	2020	RET ABN	UG-SERVICE
40247822	GRET	SVC	6/25/2022	2020	RET ABN	UG-SERVICE
36809602	GRET	SVC	8/21/2020	2020	RET ABN	UG-SERVICE
41399247	GRET	SVC	3/17/2023	2020	RET ABN	UG-SERVICE
42164914	GRET	SVC	9/26/2023	2020	RET ABN	UG-SERVICE
42274276	GRET	SVC	10/20/2023	2020	RET ABN	UG-SERVICE
38153367	GRET	SVC	2/23/2021	2020	RET ABN	UG-SERVICE
40699906	GRET	SVC	9/14/2022	2020	RET ABN	UG-SERVICE
43952089	GRET	SVC	12/17/2024	2020	RET ABN	UG-SERVICE
40837918	GRET	SVC	10/15/2022	2020	RET ABN	UG-SERVICE
40177191	GRET	SVC	5/16/2022	2020	RET ABN	UG-SERVICE
43713255	GRET	SVC	10/15/2024	2020	RET ABN	UG-SERVICE
42697535	GRET	SVC	2/14/2024	2020	RET ABN	UG-SERVICE
42702437	GRET	SVC	2/15/2024	2020	RET ABN	UG-SERVICE
39607683	GRET	SVC	12/27/2021	2020	RET ABN	UG-SERVICE
40273956	GRET	SVC	6/20/2022	2020	RET ABN	UG-SERVICE
42563288	GRET	SVC	1/10/2024	2020	RET ABN	UG-SERVICE
40633657	GRET	SVC	8/29/2022	2020	RET ABN	UG-SERVICE
41317152	GRET	SVC	3/1/2023	2020	RET ABN	UG-SERVICE
39451541	GRET	SVC	11/22/2021	2020	RET ABN	UG-SERVICE
42137985	GRET	SVC	9/18/2023	2020	RET ABN	UG-SERVICE
39524195	GRET	SVC	12/12/2021	2020	RET ABN	UG-SERVICE
40563520	GRET	SVC	8/15/2022	2020	RET ABN	UG-SERVICE
42816657	GRET	SVC	3/13/2024	2020	RET ABN	UG-SERVICE
42581343	GRET	SVC	1/18/2024	2020	RET ABN	UG-SERVICE
40607513	GRET	SVC	8/20/2022	2020	RET ABN	UG-SERVICE
41401967	GRET	SVC	3/9/2023	2020	RET ABN	UG-SERVICE
43178294	GRET	SVC	6/11/2024	2020	RET ABN	UG-SERVICE
43594940	GRET	SVC	9/16/2024	2020	RET ABN	UG-SERVICE
43710737	GRET	SVC	10/17/2024	2020	RET ABN	UG-SERVICE
42407128	GRET	SVC	12/18/2023	2020	RET ABN	UG-SERVICE
43087440	GRET	SVC	5/20/2024	2020	RET ABN	UG-SERVICE
42355274	GRET	SVC	11/13/2023	2020	RET ABN	UG-SERVICE
43800060	GRET	SVC	11/9/2024	2020	RET ABN	UG-SERVICE
43100872	GRET	SVC	8/14/2024	2020	RET ABN	UG-SERVICE
42104225	GRET	SVC	9/11/2023	2020	RET ABN	UG-SERVICE
39814000	GRET	SVC	2/28/2022	2020	RET ABN	UG-SERVICE
43709155	GRET	SVC	10/17/2024	2020	RET ABN	UG-SERVICE
40665225	GRET	SVC	9/8/2022	2020	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
43516005	GRET	SVC	9/5/2024	2020	RET ABN	UG-SERVICE
43066420	GRET	SVC	5/17/2024	2020	RET ABN	UG-SERVICE
43241292	GRET	SVC	7/29/2024	2020	RET ABN	UG-SERVICE
43826001	GRET	SVC	11/18/2024	2020	RET ABN	UG-SERVICE
43330505	GRET	SVC	7/17/2024	2020	RET ABN	UG-SERVICE
40272425	GRET	SVC	6/8/2022	2020	RET ABN	UG-SERVICE
43139809	GRET	SVC	6/3/2024	2020	RET ABN	UG-SERVICE
41429977	GRET	SVC	9/13/2023	2020	RET ABN	UG-SERVICE
43005903	GRET	SVC	4/30/2024	2020	RET ABN	UG-SERVICE
40926493	GRET	SVC	11/14/2022	2021	RET ABN	UG-SERVICE
40667659	GRET	SVC	9/12/2022	2021	RET ABN	UG-SERVICE
40383925	GRET	SVC	7/5/2022	2021	RET ABN	UG-SERVICE
40250913	GRET	SVC	6/7/2022	2021	RET ABN	UG-SERVICE
39733562	GRET	SVC	1/27/2022	2021	RET ABN	UG-SERVICE
43903134	GRET	SVC	12/2/2024	2021	RET ABN	UG-SERVICE
42379188	GRET	SVC	11/15/2023	2021	RET ABN	UG-SERVICE
43205162	GRET	SVC	6/12/2024	2021	RET ABN	UG-SERVICE
42856378	GRET	SVC	3/27/2024	2021	RET ABN	UG-SERVICE
40128902	GRET	SVC	5/8/2022	2021	RET ABN	UG-SERVICE
43184786	GRET	SVC	6/12/2024	2021	RET ABN	UG-SERVICE
42594066	GRET	SVC	1/24/2024	2021	RET ABN	UG-SERVICE
40518877	GRET	SVC	8/5/2022	2021	RET ABN	UG-SERVICE
40036551	GRET	SVC	4/20/2022	2021	RET ABN	UG-SERVICE
43676217	GRET	SVC	11/4/2024	2021	RET ABN	UG-SERVICE
42683548	GRET	SVC	2/13/2024	2021	RET ABN	UG-SERVICE
42165919	GRET	SVC	9/19/2023	2021	RET ABN	UG-SERVICE
40978225	GRET	SVC	11/23/2022	2021	RET ABN	UG-SERVICE
43081678	GRET	SVC	5/21/2024	2021	RET ABN	UG-SERVICE
41588398	GRET	SVC	5/1/2023	2021	RET ABN	UG-SERVICE
41960489	GRET	SVC	8/11/2023	2021	RET ABN	UG-SERVICE
40605060	GRET	SVC	8/31/2022	2021	RET ABN	UG-SERVICE
39406846	GRET	SVC	11/12/2021	2021	RET ABN	UG-SERVICE
41279878	GRET	SVC	3/29/2023	2021	RET ABN	UG-SERVICE
40387207	GRET	SVC	7/6/2022	2021	RET ABN	UG-SERVICE
40705964	GRET	SVC	10/24/2022	2021	RET ABN	UG-SERVICE
43932716	GRET	SVC	12/12/2024	2021	RET ABN	UG-SERVICE
43229149	GRET	SVC	7/8/2024	2021	RET ABN	UG-SERVICE
41408502	GRET	SVC	4/2/2024	2021	RET ABN	UG-SERVICE
39836180	GRET	SVC	3/2/2022	2021	RET ABN	UG-SERVICE
41981422	GRET	SVC	8/16/2023	2021	RET ABN	UG-SERVICE
41083989	GRET	SVC	12/21/2022	2021	RET ABN	UG-SERVICE
41081809	GRET	SVC	12/17/2022	2021	RET ABN	UG-SERVICE
40387113	GRET	SVC	7/6/2022	2021	RET ABN	UG-SERVICE
42067545	GRET	SVC	9/11/2023	2021	RET ABN	UG-SERVICE
43864422	GRET	SVC	11/25/2024	2021	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
40359084	GRET	SVC	6/28/2022	2021	RET ABN	UG-SERVICE
42284942	GRET	SVC	10/23/2023	2021	RET ABN	UG-SERVICE
42225311	GRET	SVC	10/11/2023	2021	RET ABN	UG-SERVICE
42051354	GRET	SVC	8/29/2023	2021	RET ABN	UG-SERVICE
43506839	GRET	SVC	10/4/2024	2021	RET ABN	UG-SERVICE
42096879	GRET	SVC	9/13/2023	2021	RET ABN	UG-SERVICE
43877243	GRET	SVC	12/18/2024	2021	RET ABN	UG-SERVICE
41974954	GRET	SVC	9/7/2023	2021	RET ABN	UG-SERVICE
39419348	GRET	SVC	11/4/2021	2021	RET ABN	UG-SERVICE
40898010	GRET	SVC	10/29/2022	2021	RET ABN	UG-SERVICE
42476013	GRET	SVC	12/8/2023	2021	RET ABN	UG-SERVICE
43364871	GRET	SVC	12/18/2024	2021	RET ABN	UG-SERVICE
40589919	GRET	SVC	8/17/2022	2021	RET ABN	UG-SERVICE
41821807	GRET	SVC	7/3/2023	2021	RET ABN	UG-SERVICE
43027221	GRET	SVC	5/17/2024	2021	RET ABN	UG-SERVICE
39837038	GRET	SVC	2/28/2022	2021	RET ABN	UG-SERVICE
41417314	GRET	SVC	3/20/2023	2021	RET ABN	UG-SERVICE
40481487	GRET	SVC	7/25/2022	2021	RET ABN	UG-SERVICE
43736054	GRET	SVC	10/17/2024	2021	RET ABN	UG-SERVICE
42429616	GRET	SVC	11/28/2023	2021	RET ABN	UG-SERVICE
43546001	GRET	SVC	9/9/2024	2021	RET ABN	UG-SERVICE
39419153	GRET	SVC	11/4/2021	2021	RET ABN	UG-SERVICE
43440686	GRET	SVC	8/18/2024	2021	RET ABN	UG-SERVICE
41670150	GRET	SVC	5/26/2023	2021	RET ABN	UG-SERVICE
43605417	GRET	SVC	9/24/2024	2021	RET ABN	UG-SERVICE
39570589	GRET	SVC	12/7/2021	2021	RET ABN	UG-SERVICE
39968191	GRET	SVC	4/6/2022	2021	RET ABN	UG-SERVICE
39419346	GRET	SVC	11/4/2021	2021	RET ABN	UG-SERVICE
39445837	GRET	SVC	11/22/2021	2021	RET ABN	UG-SERVICE
40367143	GRET	SVC	6/28/2022	2021	RET ABN	UG-SERVICE
43324182	GRET	SVC	7/31/2024	2021	RET ABN	UG-SERVICE
39660430	GRET	SVC	1/4/2022	2021	RET ABN	UG-SERVICE
40445072	GRET	SVC	8/10/2022	2021	RET ABN	UG-SERVICE
39419359	GRET	SVC	11/4/2021	2021	RET ABN	UG-SERVICE
43364870	GRET	SVC	12/4/2024	2021	RET ABN	UG-SERVICE
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39419351	GRET	SVC	11/4/2021	2021	RET ABN	UG-SERVICE
41810741	GRET	SVC	6/24/2023	2021	RET ABN	UG-SERVICE
39304588	GRET	SVC	10/18/2021	2021	RET ABN	UG-SERVICE
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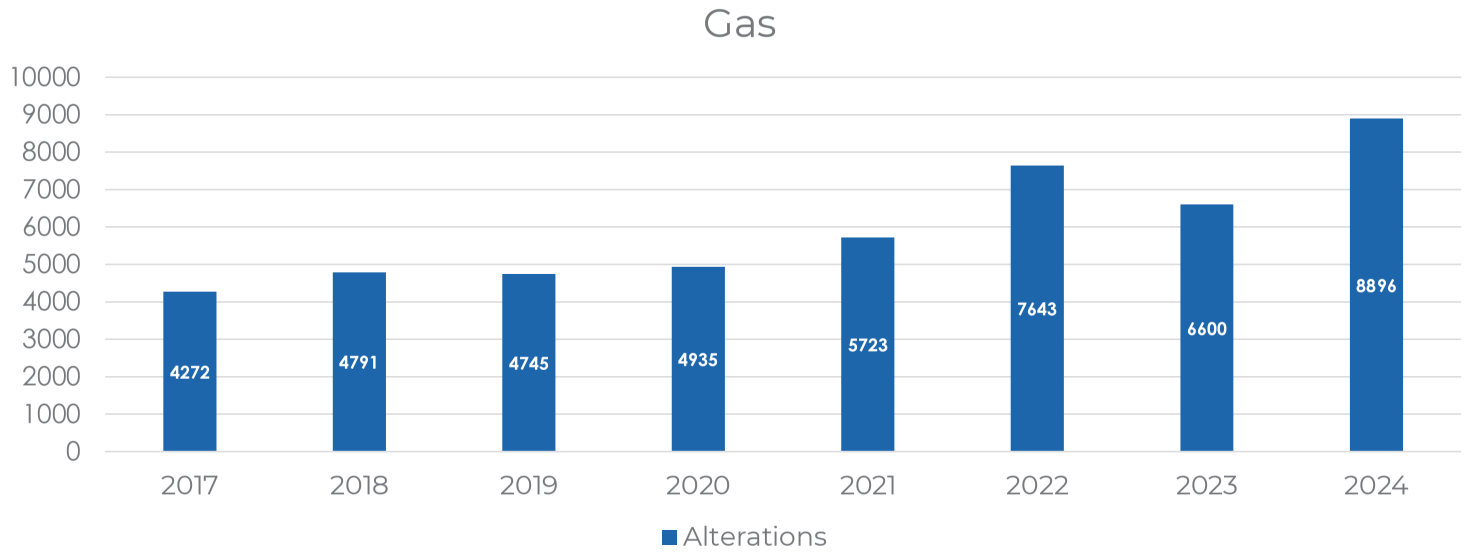
42161019	GRET	SVC	9/25/2023	2021	RET ABN	UG-SERVICE
42053020	GRET	SVC	8/31/2023	2021	RET ABN	UG-SERVICE
43323978	GRET	SVC	10/18/2024	2021	RET ABN	UG-SERVICE
39220296	GRET	SVC	10/4/2021	2021	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41193702	GRET	SVC	1/23/2023	2021	RET ABN	UG-SERVICE
40906483	GRET	SVC	11/9/2022	2021	RET ABN	UG-SERVICE
42494285	GRET	SVC	12/18/2023	2021	RET ABN	UG-SERVICE
40172796	GRET	SVC	5/18/2022	2021	RET ABN	UG-SERVICE
41610797	GRET	SVC	5/6/2023	2021	RET ABN	UG-SERVICE
41096317	GRET	SVC	1/17/2023	2021	RET ABN	UG-SERVICE
39419355	GRET	SVC	11/4/2021	2021	RET ABN	UG-SERVICE
39940284	GRET	SVC	3/29/2022	2021	RET ABN	UG-SERVICE
43341451	GRET	SVC	7/22/2024	2021	RET ABN	UG-SERVICE
41693187	GRET	SVC	6/1/2023	2021	RET ABN	UG-SERVICE
41645626	GRET	SVC	5/13/2023	2021	RET ABN	UG-SERVICE
40572170	GRET	SVC	8/16/2022	2021	RET ABN	UG-SERVICE
43604842	GRET	SVC	9/30/2024	2021	RET ABN	UG-SERVICE
40727970	GRET	SVC	9/23/2022	2021	RET ABN	UG-SERVICE
41214688	GRET	SVC	1/31/2023	2022	RET ABN	UG-SERVICE
43094986	GRET	SVC	5/26/2024	2022	RET ABN	UG-SERVICE
42202874	GRET	SVC	10/10/2023	2022	RET ABN	UG-SERVICE
40659650	GRET	SVC	9/7/2022	2022	RET ABN	UG-SERVICE
43883409	GRET	SVC	11/25/2024	2022	RET ABN	UG-SERVICE
43429214	GRET	SVC	8/14/2024	2022	RET ABN	UG-SERVICE
43680049	GRET	SVC	10/31/2024	2022	RET ABN	UG-SERVICE
40392550	GRET	SVC	7/8/2022	2022	RET ABN	UG-SERVICE
44002386	GRET	SVC	12/20/2024	2022	RET ABN	UG-SERVICE
42691237	GRET	SVC	2/12/2024	2022	RET ABN	UG-SERVICE
41059853	GRET	SVC	12/12/2022	2022	RET ABN	UG-SERVICE
42432422	GRET	SVC	12/1/2023	2022	RET ABN	UG-SERVICE
40894333	GRET	SVC	10/27/2022	2022	RET ABN	UG-SERVICE
43480984	GRET	SVC	10/13/2024	2022	RET ABN	UG-SERVICE
42193518	GRET	SVC	10/16/2023	2022	RET ABN	UG-SERVICE
41545560	GRET	SVC	4/20/2023	2022	RET ABN	UG-SERVICE
40903511	GRET	SVC	11/7/2022	2022	RET ABN	UG-SERVICE
41418426	GRET	SVC	3/20/2023	2022	RET ABN	UG-SERVICE
43414528	GRET	SVC	8/14/2024	2022	RET ABN	UG-SERVICE
41505970	GRET	SVC	4/12/2023	2022	RET ABN	UG-SERVICE
41707319	GRET	SVC	6/6/2023	2022	RET ABN	UG-SERVICE
40812853	GRET	SVC	11/4/2022	2022	RET ABN	UG-SERVICE
43141795	GRET	SVC	6/5/2024	2022	RET ABN	UG-SERVICE
42227332	GRET	SVC	10/13/2023	2022	RET ABN	UG-SERVICE
40999526	GRET	SVC	11/14/2022	2022	RET ABN	UG-SERVICE
42009420	GRET	SVC	8/11/2023	2022	RET ABN	UG-SERVICE
40358436	GRET	SVC	6/18/2022	2022	RET ABN	UG-SERVICE
41433515	GRET	SVC	4/10/2023	2022	RET ABN	UG-SERVICE
43088863	GRET	SVC	5/20/2024	2022	RET ABN	UG-SERVICE
42886917	GRET	SVC	4/5/2024	2022	RET ABN	UG-SERVICE
43442961	GRET	SVC	8/29/2024	2022	RET ABN	UG-SERVICE

order_number	order_type	maintenance_activity_type	field_complete_date	vintage_year	cu_action	cu_type
41832561	GRET	SVC	6/29/2023	2022	RET ABN	UG-SERVICE
42945490	GRET	SVC	4/16/2024	2023	RET ABN	UG-SERVICE
41838260	GRET	SVC	7/7/2023	2023	RET ABN	UG-SERVICE
43250339	GRET	SVC	12/11/2024	2023	RET ABN	UG-SERVICE
43250337	GRET	SVC	12/13/2024	2023	RET ABN	UG-SERVICE
42999743	GRET	SVC	4/30/2024	2023	RET ABN	UG-SERVICE
42025517	GRET	SVC	8/19/2023	2023	RET ABN	UG-SERVICE
43504818	GRET	SVC	9/4/2024	2023	RET ABN	UG-SERVICE
42903146	GRET	SVC	4/10/2024	2023	RET ABN	UG-SERVICE
41818281	GRET	SVC	6/29/2023	2023	RET ABN	UG-SERVICE
42855908	GRET	SVC	3/28/2024	2023	RET ABN	UG-SERVICE
43333372	GRET	SVC	7/29/2024	2023	RET ABN	UG-SERVICE
42835352	GRET	SVC	3/18/2024	2023	RET ABN	UG-SERVICE
43635836	GRET	SVC	9/30/2024	2024	RET ABN	UG-SERVICE
43352875	GRET	SVC	7/12/2024	2024	RET ABN	UG-SERVICE
43397594	GRET	SVC	8/12/2024	2024	RET ABN	UG-SERVICE

Customer Requested Alterations



2017 to 2024 (8 years) 108% increase in alteration requests

Alterations = Upgrades, Relocates, etc.

Cost of Gas Construction

New Business

2023

Luther Bonner

Customer Energy Management Process, Performance & Technology Lead

Consumers Energy

Count on Us®

Consumers Energy
Count on Us

Per Foot Rates and Excess Service Costs

2021/2022 Rates

Residential	Service		2" Main		4" Main		6" Main
Gas Only	$ 29.47		$ 17.13		$ 54.01		$ 61.58
Joint	$ 25.60		$ 22.49		$ 68.13		$ 44.66
Directional Bore	Addl $8.80/ft		$ 53.15		$ 104.21		$ 182.17
Non-Residential							
Gas Only	$ 42.90		$ 17.13		$ 54.01		$ 61.58
Joint	$ 25.60		$ 22.49		$ 68.13		$ 44.66
Directional Bore	Addl $8.80/ft		$ 53.15		$ 104.21		$ 182.17

2023 Rates

36% increase in 2" Plastic Main

Residential	Service		2" Main		4" Main		6" Main
Gas Only	$36.82		$23.36		$79.90		$110.22
Joint	$29.23		$29.46		$100.83		$124.34
Directional Bore	Addl $8.80/ft		$67.31		$105.03		$185.67
Non-Residential							
Gas Only	$47.01		$23.36		$79.90		$110.22
Joint	$29.23		$29.46		$100.83		$124.34
Directional Bore	Addl $8.80/ft		$67.31		$105.03		$185.67

Consumers Energy
Count on Us

Free Footage Allowances

2021/2022

Residential Category		Allowable Footage Gas Only		Joint
	Primary 250	158		227
	Primary 425	544		672
	Primary 800	1071		1278
	Seasonal	0		24
	Mobile Home	52		105

- **Seasonal**
  - **No specific data field available to segment seasonal loads**
  - **Consumptions 40mcf annually or lower equate to 10% of Customer Base, removal does not change average**
- **Mobile**
  - **No specific data field available to segment mobile loads**
  - **Modular homes are less efficient then stick built, makes sense to offer and include within the overall average**
- **425 & 800**
  - **Consumptions 400 and greater annually equate to .001% of Customer Base, removal does not change average**
  - **13% of the 10,500 new meters installed in 2021 were 425/800. 10,500/1,300,000 = .008% - .001% = .007%/.008% = 12.5% of the 13% consume the annual MCF allotted, 87.5% of 425/800 meters installed in 2021 fall within the average of 97 annually**
- **Apartments (Apt)**
  - **Including Apts changes average from 97 to 93, 10% of customer base, already use the same service line limits**

2023

Category		Allowable Footage Gas Only		Joint
	Residential	92		138

Residential Annual MCF Revenue

Average Installation Count				
	2020	2021	2022	3 Year
No	1,325,721	1,330,227	1,325,163	1,327,037
Yes	136,706	136,417	131,448	134,857

Average Consumption by Heating Season (Oct-May)				
	APT	Consumption	Premise Count	Ave Consumption
2020/21	NO	113,348,851.50	1,327,974	85
2020/21	YES	6,356,449.70	136,562	47
2021/22	NO	121,234,436.20	1,327,695	91
2021/22	YES	6,773,597.70	133,932	51

Average Consumption Non-Heating Season (Jun-Sep)				
	APT	Consumption	Premise Count	Ave Consumption
2021	NO	11,704,567.30	1,330,227	9
2021	YES	581,704.20	136,417	4
2022	NO	10,979,509.60	1,325,163	8
2022	YES	530,665.20	131,448	4

Average Consumption Previous Full Seasons (Jul-Jun)				
	APT	Consumption	Premise Count	Ave Consumption
2020/21	NO	125,236,446.30	1,327,974	94
2020/21	YES	6,951,819.50	136,562	51
2021/22	NO	132,371,784.00	1,327,695	100
2021/22	YES	7,321,306.40	133,932	55
2 Year	NO	128,804,115.15	1,327,037	97
2 Year	YES	7,136,562.95	134,857	53

Prior Years

Class	Description	Meter	MCF
250	Permanent Structure	250	150
Apt	Apartments, Condos	250	85
Mobile	Modular Homes	250	84
Season	250/Mobile used Seasonally	250	40
425	Permanent Structure	425	400
800	Permanent Structure	800	750

New 2yr Average – Decrease of 65%

Class	Description	Meter	MCF
Res	Permanent Structures, Modular, Seasonal	Any	97
Apt	Apartments, Condos (Multi Unit Buildings)	Any	53

Customer Impacts

- **38% of NBS Customers & 27% of NJS Customers with longer service requirements will see higher costs due to excess service charges per ft after the service line limit**

- **Average residential customer will see $736.40 increase based on average service length**
  - **62% of NBS customers within the past 3 years would have had no impact**
  - **73% of NJS customer within the past 3 years would have had no impact**

- **20 lot Subdivision scenario –**
  - **$86,196.39 increase using the service line limit 92'**
  - **$88,783.94 increase using the average service length of 112'**
  - **$78,174.94 Typical Subdivisions have an average of 30' services for subdivisions**

- **Developments with larger lots & longer service requirements will see increase in upfront costs**
- **Customers requiring larger meters will only see increase in costs if service length exceeds limit**
- **Company is truing up recovery of costs of service based on current consumption data (2-year average) and current construction costs (3-year average)**

Customer Impacts Development Scenario

2021/2022 Rates

- 5000’ Normal trench 2” plastic
- 20 lot development – NEW service limit 92’
- Original MCF – 150 annually
- Costs

Year 1 Construction Costs	
Main	$85,650.00
Service	$22,258.85
Meter	$1,129.50
Direct Charge	$0.00
Permit Costs	$0.00
Total	**$109,038.35**

Customer Costs	
Main	$85,650.00
Service	$89,035.40
Meter	$4,518.00
Conn Fee	$0.00
Direct Charge	$0.00
Permit Costs	$0.00
Rev Cred/Op Exp	($117,089.12)
Total	**$62,114.28**

2023 Rates

- 5000’ Normal trench 2” plastic
- 20 lot development – NEW service limit 92’
- NEW MCF – 97 annually
- Costs

Year 1 Construction Costs	
Main	$116,800.00
Service	$24,802.30
Meter	$1,129.50
Direct Charge	$0.00
Permit Costs	$0.00
Total	**$142,731.80**

Customer Costs	
Main	$116,800.00
Service	$99,209.20
Meter	$4,518.00
Conn Fee	$0.00
Direct Charge	$0.00
Permit Costs	$0.00
Rev Cred/Op Exp	($72,216.53)
Total	**$148,310.67**

Gem Billables Summary

Year 1 Main Cost	Year 1 Service Cost	Year 1 Meter Cost	Year 1 Direct Cost
116800.00	24802.30	1129.50	0.00
Total Main Cost	Total Service Cost	Total Meter Cost	Total Additional Cost
116800.00	99209.20	4517.99	0.00
Net Present Value Cost	Net Present Value Revenue	Net Present Value Difference	
237211.91	100624.85	136587.06	
Net Present Value Gross Up			
148310.66			
Total Customer Cost	Status		
148310.66	Billed		

Customer Impacts Development Scenario

2021/2022 Rates

- **5000’ Normal trench 2” plastic**
- **20 lot development – service limit 112’**
- **Original MCF – 150 annually**
- **Costs**

Year 1 Construction Costs	
Main	$85,650.00
Service	$24,568.85
Meter	$1,129.50
Direct Charge	$0.00
Permit Costs	$0.00
Total	**$111,348.35**

Customer Costs	
Main	$85,650.00
Service	$98,275.40
Meter	$4,518.00
Conn Fee	$0.00
Direct Charge	$0.00
Permit Costs	$0.00
Rev Cred/Op Exp	($116,400.10)
Total	**$72,043.30**

2023 Rates

- **5000’ Normal trench 2” plastic**
- **20 lot development – NEW service limit 112’**
- **NEW MCF – 97 annually**
- **Costs**

Year 1 Construction Costs	
Main	$116,800.00
Service	$27,714.30
Meter	$1,129.50
Direct Charge	$0.00
Permit Costs	$0.00
Total	**$145,643.80**

Customer Costs	
Main	$116,800.00
Service	$110,857.20
Meter	$4,518.00
Conn Fee	$0.00
Direct Charge	$0.00
Permit Costs	$0.00
Rev Cred/Op Exp	($71,347.96)
Total	**$160,827.24**

Gem Billables Summary

Year 1 Main Cost	Year 1 Service Cost	Year 1 Meter Cost	Year 1 Direct Cost
116800.00	27714.30	1129.50	0.00
Total Main Cost	**Total Service Cost**	**Total Meter Cost**	**Total Additional Cost**
116800.00	110857.20	4517.99	0.00
Net Present Value Cost	**Net Present Value Revenue**	**Net Present Value Difference**	
248739.09	100624.85	148114.23	
Net Present Value Gross Up			
160827.24			
Total Customer Cost	**Status**		
160827.24	Billed		

Customer Impacts Development Scenario

2021/2022 Rates

- 5000’ Normal trench 2” plastic
- 20 lot development – service limit 30’
- Original MCF – 150 annually
- Costs

Year 1 Construction Costs	
Main	$85,650.00
Service	$15,097.85
Meter	$1,129.50
Direct Charge	$0.00
Permit Costs	$0.00
Total	**$101,877.35**

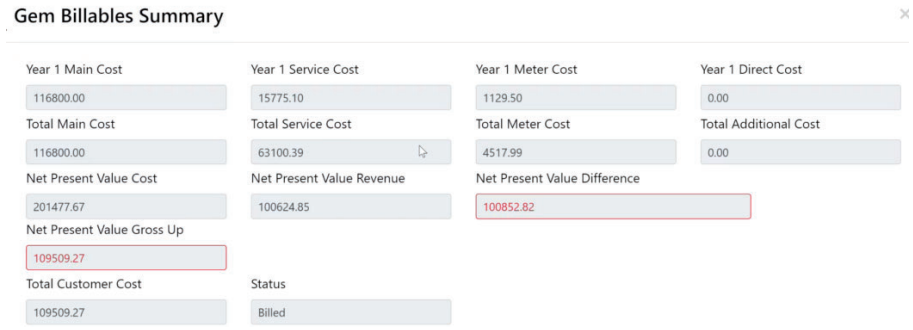
Customer Costs	
Main	$85,650.00
Service	$60,391.40
Meter	$4,518.00
Conn Fee	$0.00
Direct Charge	$0.00
Permit Costs	$0.00
Rev Cred/Op Exp	($119,225.07)
Total	**$31,334.33**

2023 Rates

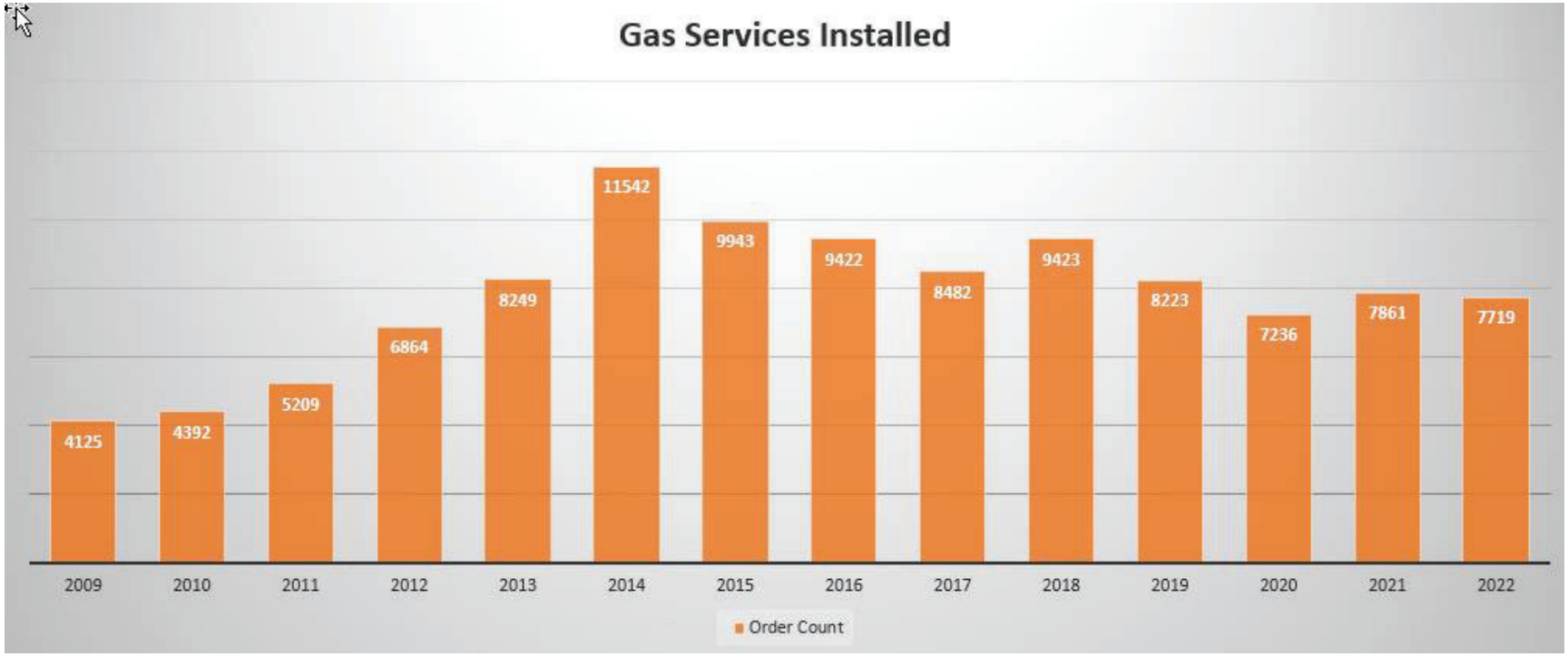
- 5000’ Normal trench 2” plastic
- 20 lot development – NEW service limit 30’
- NEW MCF – 97 annually
- Costs

Year 1 Construction Costs	
Main	$116,800.00
Service	$15,775.10
Meter	$1,129.50
Direct Charge	$0.00
Permit Costs	$0.00
Total	**$133,704.60**

Customer Costs	
Main	$116,800.00
Service	$63,100.40
Meter	$4,518.00
Conn Fee	$0.00
Direct Charge	$0.00
Permit Costs	$0.00
Rev Cred/Op Exp	($74,909.13)
Total	**$109,509.27**



New Business Gas Connections



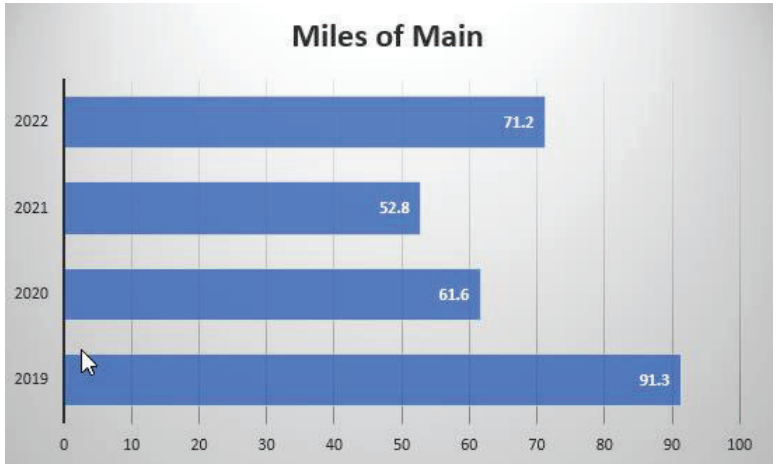
2023 New Business Review

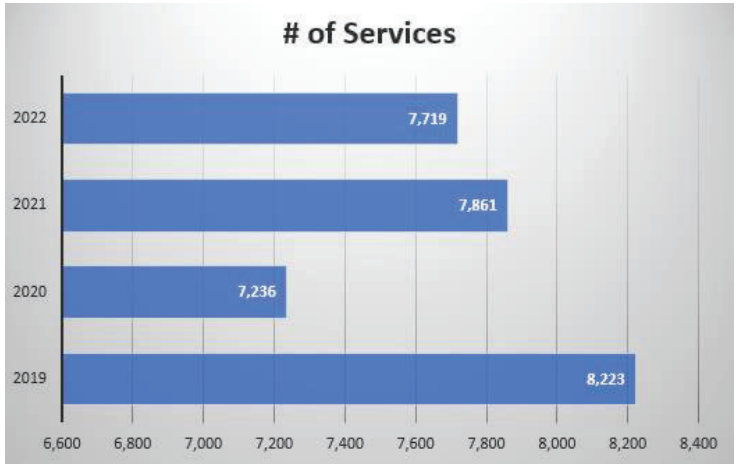
Gas Main Installation

- 2022 = 71.2 miles
- 2021 = 52.8 miles
- 2020 = 61.6 miles
- 2019 = 91.3 miles

Gas Service Installation

- 2022 = 7,719 services
- 2021 = 7,861 services
- 2020 = 7,236 services
- 2019 = 8,223 services





Consumers Energy
Count on Us

Questions?

COST OF EQUITY ANALYSES
SUMMARY OF RESULTS

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.99%	10.86%	11.68%
90-Day Avg. Stock Price	10.09%	10.97%	11.78%
180-Day Avg. Stock Price	10.17%	11.05%	11.86%
Average	10.08%	10.96%	11.77%
Median Results:			
30-Day Avg. Stock Price	9.78%	10.91%	12.14%
90-Day Avg. Stock Price	9.92%	11.06%	12.28%
180-Day Avg. Stock Price	10.10%	11.24%	12.47%
Average	9.93%	11.07%	12.30%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.25%	11.23%	11.22%
Current Bloomberg Beta	10.11%	10.05%	10.02%
Long-term Avg. *Value Line* Beta	10.23%	10.18%	10.14%
ECAPM:			
Current *Value Line* Beta	11.42%	11.40%	11.39%
Current Bloomberg Beta	10.56%	10.52%	10.49%
Long-term Avg. *Value Line* Beta	10.65%	10.61%	10.59%
Bond Yield Risk Premium	10.55%	10.41%	10.33%

30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Capital IQ Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.48	$152.74	2.28%	2.36%	6.00%	7.20%	7.47%	6.89%	8.35%	9.25%	9.83%
NiSource Inc.	NI	$1.12	$39.15	2.86%	2.98%	9.50%	7.90%	7.96%	8.45%	10.87%	11.43%	12.50%
Northwest Natural Gas Company	NWN	$1.96	$42.13	4.65%	4.82%	6.50%	n/a	8.25%	7.38%	11.30%	12.20%	13.09%
ONE Gas, Inc.	OGS	$2.68	$75.20	3.56%	3.65%	4.00%	5.60%	5.17%	4.92%	7.64%	8.57%	9.26%
Southwest Gas Corporation	SWX	$2.48	$72.58	3.42%	3.58%	10.00%	9.50%	n/a	9.75%	13.08%	13.33%	13.59%
Spire, Inc.	SR	$3.14	$76.80	4.09%	4.21%	4.50%	6.50%	7.54%	6.18%	8.68%	10.39%	11.78%
Mean		$2.48	$76.43	3.48%	3.60%	6.75%	7.34%	7.28%	7.26%	9.99%	10.86%	11.68%
Median		$2.58	$73.89	3.49%	3.62%	6.25%	7.20%	7.54%	7.13%	9.78%	10.91%	12.14%

Notes:
[1] Bloomberg Professional as of April 25, 2025
[2] Bloomberg Professional 30-day average as of April 25, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] Capital IQ
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Capital IQ Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	3.48	$146.67	2.37%	2.45%	6.00%	7.20%	7.47%	6.89%	8.44%	9.34%	9.93%
NiSource Inc.	NI	1.12	$38.31	2.92%	3.05%	9.50%	7.90%	7.96%	8.45%	10.94%	11.50%	12.56%
Northwest Natural Gas Company	NWN	1.96	$40.98	4.78%	4.96%	6.50%	n/a	8.25%	7.38%	11.44%	12.33%	13.23%
ONE Gas, Inc.	OGS	2.68	$72.49	3.70%	3.79%	4.00%	5.60%	5.17%	4.92%	7.77%	8.71%	9.40%
Southwest Gas Corporation	SWX	2.48	$73.04	3.40%	3.56%	10.00%	9.50%	n/a	9.75%	13.06%	13.31%	13.57%
Spire, Inc.	SR	3.14	$73.02	4.30%	4.43%	4.50%	6.50%	7.54%	6.18%	8.90%	10.61%	12.00%
Mean		$2.48	$74.08	3.58%	3.71%	6.75%	7.34%	7.28%	7.26%	10.09%	10.97%	11.78%
Median		$2.58	$72.75	3.55%	3.67%	6.25%	7.20%	7.54%	7.13%	9.92%	11.06%	12.28%

Notes:
[1] Bloomberg Professional as of April 25, 2025
[2] Bloomberg Professional 90-day average as of April 25, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] Capital IQ
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Capital IQ Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
Atmos Energy Corporation	ATO	$3.48	$142.59	2.44%	2.52%	6.00%	7.20%	7.47%	6.89%	8.51%	9.41%	10.00%
NiSource Inc.	NI	$1.12	$36.47	3.07%	3.20%	9.50%	7.90%	7.96%	8.45%	11.09%	11.65%	12.72%
Northwest Natural Gas Company	NWN	$1.96	$40.67	4.82%	5.00%	6.50%	n/a	8.25%	7.38%	11.48%	12.37%	13.27%
ONE Gas, Inc.	OGS	$2.68	$72.35	3.70%	3.80%	4.00%	5.60%	5.17%	4.92%	7.78%	8.72%	9.41%
Southwest Gas Corporation	SWX	$2.48	$73.44	3.38%	3.54%	10.00%	9.50%	n/a	9.75%	13.04%	13.29%	13.55%
Spire, Inc.	SR	$3.14	$69.72	4.50%	4.64%	4.50%	6.50%	7.54%	6.18%	9.11%	10.82%	12.21%
Mean		$2.48	$72.54	3.65%	3.78%	6.75%	7.34%	7.28%	7.26%	10.17%	11.05%	11.86%
Median		$2.58	$71.03	3.54%	3.67%	6.25%	7.20%	7.54%	7.13%	10.10%	11.24%	12.47%

Notes:
[1] Bloomberg Professional as of April 25, 2025
[2] Bloomberg Professional 180-day average as of April 25, 2025
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Zacks
[7] Capital IQ
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.68%	0.90	11.92%	7.24%	11.19%	11.37%
NiSource Inc.	NI	4.68%	0.95	11.92%	7.24%	11.55%	11.64%
Northwest Natural Gas Company	NWN	4.68%	0.90	11.92%	7.24%	11.19%	11.37%
ONE Gas, Inc.	OGS	4.68%	0.85	11.92%	7.24%	10.83%	11.10%
Southwest Gas Corporation	SWX	4.68%	0.95	11.92%	7.24%	11.55%	11.64%
Spire, Inc.	SR	4.68%	0.90	11.92%	7.24%	11.19%	11.37%
Mean						11.25%	11.42%
Median						11.19%	11.37%

Notes:
[1] Bloomberg Professional 30-day average as of April 25, 2025
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta\,(Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2025 - Q3 2026)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.44%	0.90	11.92%	7.48%	11.17%	11.35%
NiSource Inc.	NI	4.44%	0.95	11.92%	7.48%	11.54%	11.63%
Northwest Natural Gas Company	NWN	4.44%	0.90	11.92%	7.48%	11.17%	11.35%
ONE Gas, Inc.	OGS	4.44%	0.85	11.92%	7.48%	10.79%	11.07%
Southwest Gas Corporation	SWX	4.44%	0.95	11.92%	7.48%	11.54%	11.63%
Spire, Inc.	SR	4.44%	0.90	11.92%	7.48%	11.17%	11.35%
Mean						11.23%	11.40%
Median						11.17%	11.35%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 44, No. 5, May 1, 2025, at 2
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND VALUE LINE BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2026 - 2030)	[2] Beta	[3] Market Return	[4] Market Risk Premium	[5] Cost of Equity: CAPM	[6] Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.30%	0.90	11.92%	7.62%	11.15%	11.34%
NiSource Inc.	NI	4.30%	0.95	11.92%	7.62%	11.53%	11.63%
Northwest Natural Gas Company	NWN	4.30%	0.90	11.92%	7.62%	11.15%	11.34%
ONE Gas, Inc.	OGS	4.30%	0.85	11.92%	7.62%	10.77%	11.06%
Southwest Gas Corporation	SWX	4.30%	0.95	11.92%	7.62%	11.53%	11.63%
Spire, Inc.	SR	4.30%	0.90	11.92%	7.62%	11.15%	11.34%
Mean						11.22%	11.39%
Median						11.15%	11.34%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14
[2] Value Line
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.68%	0.73	11.92%	7.24%	9.98%	10.46%
NiSource Inc.	NI	4.68%	0.78	11.92%	7.24%	10.33%	10.72%
Northwest Natural Gas Company	NWN	4.68%	0.68	11.92%	7.24%	9.62%	10.19%
ONE Gas, Inc.	OGS	4.68%	0.75	11.92%	7.24%	10.08%	10.54%
Southwest Gas Corporation	SWX	4.68%	0.82	11.92%	7.24%	10.59%	10.92%
Spire, Inc.	SR	4.68%	0.75	11.92%	7.24%	10.07%	10.53%
Mean						10.11%	10.56%
Median						10.08%	10.54%

Notes:
[1] Bloomberg Professional 30-day average as of April 25, 2025
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2025 - Q3 2026)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.44%	0.73	11.92%	7.48%	9.91%	10.41%
NiSource Inc.	NI	4.44%	0.78	11.92%	7.48%	10.28%	10.69%
Northwest Natural Gas Company	NWN	4.44%	0.68	11.92%	7.48%	9.54%	10.14%
ONE Gas, Inc.	OGS	4.44%	0.75	11.92%	7.48%	10.02%	10.49%
Southwest Gas Corporation	SWX	4.44%	0.82	11.92%	7.48%	10.54%	10.89%
Spire, Inc.	SR	4.44%	0.75	11.92%	7.48%	10.01%	10.49%
Mean						10.05%	10.52%
Median						10.01%	10.49%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 44, No. 5, May 1, 2025, at 2
[2] Bloomberg Professional
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK-FREE RATE AND BLOOMBERG BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.30%	0.73	11.92%	7.62%	9.87%	10.38%
NiSource Inc.	NI	4.30%	0.78	11.92%	7.62%	10.24%	10.66%
Northwest Natural Gas Company	NWN	4.30%	0.68	11.92%	7.62%	9.50%	10.10%
ONE Gas, Inc.	OGS	4.30%	0.75	11.92%	7.62%	9.98%	10.46%
Southwest Gas Corporation	SWX	4.30%	0.82	11.92%	7.62%	10.52%	10.87%
Spire, Inc.	SR	4.30%	0.75	11.92%	7.62%	9.98%	10.46%
Mean						10.02%	10.49%
Median						9.98%	10.46%

Notes:

[1] Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14

[2] Bloomberg Professional

[3] Market Return

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.68%	0.76	11.92%	7.24%	10.20%	10.63%
NiSource Inc.	NI	4.68%	0.78	11.92%	7.24%	10.29%	10.69%
Northwest Natural Gas Company	NWN	4.68%	0.73	11.92%	7.24%	9.93%	10.42%
ONE Gas, Inc.	OGS	4.68%	0.75	11.92%	7.24%	10.11%	10.56%
Southwest Gas Corporation	SWX	4.68%	0.84	11.92%	7.24%	10.74%	11.03%
Spire, Inc.	SR	4.68%	0.75	11.92%	7.24%	10.14%	10.58%
Mean						10.23%	10.65%
Median						10.17%	10.60%

Notes:
[1] Bloomberg Professional 30-day average as of April 25, 2025
[2] Source: LT Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
NEAR-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q3 2025 - Q3 2026)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.44%	0.76	11.92%	7.48%	10.14%	10.58%
NiSource Inc.	NI	4.44%	0.78	11.92%	7.48%	10.23%	10.65%
Northwest Natural Gas Company	NWN	4.44%	0.73	11.92%	7.48%	9.86%	10.37%
ONE Gas, Inc.	OGS	4.44%	0.75	11.92%	7.48%	10.05%	10.51%
Southwest Gas Corporation	SWX	4.44%	0.84	11.92%	7.48%	10.70%	11.00%
Spire, Inc.	SR	4.44%	0.75	11.92%	7.48%	10.08%	10.54%
Mean						10.18%	10.61%
Median						10.11%	10.56%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 44, No. 5, May 1, 2025, at 2
[2] Source: LT Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL
LONG-TERM PROJECTED RISK FREE RATE AND LONG-TERM VALUE LINE BETA

$$K = Rf + \beta\ (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2026 - 2030)	Beta	Market Return	Market Risk Premium	Cost of Equity: CAPM	Cost of Equity: ECAPM
Atmos Energy Corporation	ATO	4.30%	0.76	11.92%	7.62%	10.11%	10.56%
NiSource Inc.	NI	4.30%	0.78	11.92%	7.62%	10.20%	10.63%
Northwest Natural Gas Company	NWN	4.30%	0.73	11.92%	7.62%	9.82%	10.34%
ONE Gas, Inc.	OGS	4.30%	0.75	11.92%	7.62%	10.01%	10.49%
Southwest Gas Corporation	SWX	4.30%	0.84	11.92%	7.62%	10.68%	10.99%
Spire, Inc.	SR	4.30%	0.75	11.92%	7.62%	10.04%	10.51%
Mean						10.14%	10.59%
Median						10.07%	10.53%

Notes:

[1] Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14

[2] Source: LT Beta

[3] Market Return

[4] Equals [3]-[1]

[5] Equals [1] + [2] x [4]

[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL BETA

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
Company	Ticker	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	12/31/2023	12/31/2024	Average
Atmos Energy Corporation	ATO	0.80	0.80	0.80	0.70	0.70	0.60	0.60	0.80	0.80	0.80	0.85	0.90	0.76
NiSource Inc.	NI	0.85	0.85	NMF	NMF	0.60	0.50	0.55	0.85	0.85	0.85	0.90	0.95	0.78
Northwest Natural Gas Company	NWN	0.65	0.70	0.65	0.65	0.70	0.60	0.60	0.80	0.85	0.80	0.80	0.90	0.73
ONE Gas, Inc.	OGS				0.70	0.70	0.65	0.65	0.80	0.80	0.80	0.80	0.85	0.75
Southwest Gas Corporation	SWX	0.80	0.85	0.80	0.75	0.80	0.70	0.70	0.95	0.95	0.90	0.90	0.95	0.84
Spire, Inc.	SR	0.65	0.70	0.70	0.70	0.70	0.65	0.65	0.85	0.85	0.85	0.85	0.90	0.75
Mean		0.75	0.78	0.74	0.70	0.70	0.62	0.63	0.84	0.85	0.83	0.85	0.91	0.77

Notes:
[1] Value Line, dated December 26, 2013.
[2] Value Line, dated December 31, 2014.
[3] Value Line, dated December 30, 2015.
[4] Value Line, dated December 29, 2016.
[5] Value Line, dated December 28, 2017.
[6] Value Line, dated December 27, 2018.
[7] Value Line, dated December 26, 2019.
[8] Value Line, dated December 30, 2020.
[9] Value Line, dated December 29, 2021.
[10] Value Line, dated December 30, 2022.
[11] Value Line, Dated December 29, 2023.
[12] Value Line, Dated December 27, 2024.

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.52%
[2] Estimate of the S&P 500 Growth Rate	10.32%
[3] S&P 500 Estimated Required Market Return	11.92%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	321.40	59.44	19,104.02	0.05%	9.02%	0.00%	7.03%	0.00%
American Express Co	AXP	700.59	264.81	185,522.94	0.51%	1.24%	0.01%	14.77%	0.08%
Verizon Communications Inc	VZ	4216.25	41.91	176,703.24	0.49%	6.47%	0.03%	2.62%	0.01%
Texas Pacific Land Corp	TPL	22.98	1334.63	30,676.20		0.48%			
Broadcom Inc	AVGO	4701.95	192.31	904,231.76		1.23%		23.48%	
Boeing Co/The	BA	754.01	177.95	134,175.27				31.75%	
Solventum Corp	SOLV	173.00	66.07	11,430.30				-0.35%	
Caterpillar Inc	CAT	477.93	306.45	146,462.27		1.84%			
JPMorgan Chase & Co	JPM	2783.00	243.55	677,798.75	1.88%	2.30%	0.04%	4.54%	0.09%
Chevron Corp	CVX	1746.72	138.73	242,322.36	0.67%	4.93%	0.03%	11.52%	0.08%
Coca-Cola Co/The	KO	4303.57	71.91	309,469.49	0.86%	2.84%	0.02%	5.69%	0.05%
AbbVie Inc	ABBV	1768.98	186.06	329,136.10	0.91%	3.53%	0.03%	16.08%	0.15%
Walt Disney Co/The	DIS	1807.79	90.28	163,207.18	0.45%	1.11%	0.01%	11.36%	0.05%
Corpay Inc	CPAY	70.25	322.03	22,622.58	0.06%			11.73%	0.01%
Extra Space Storage Inc	EXR	212.23	141.05	29,934.39	0.08%	4.59%	0.00%	2.83%	0.00%
Exxon Mobil Corp	XOM	4325.29	108.57	469,597.13	1.30%	3.65%	0.05%	7.58%	0.10%
Phillips 66	PSX	407.44	103.97	42,361.25		4.62%		24.39%	
General Electric Co	GE	1066.39	198.43	211,603.10	0.59%	0.73%	0.00%	18.48%	0.11%
HP Inc	HPQ	942.70	25.28	23,831.53	0.07%	4.58%	0.00%	1.55%	0.00%
Home Depot Inc/The	HD	993.93	357.58	355,408.83	0.99%	2.57%	0.03%	5.11%	0.05%
Monolithic Power Systems Inc	MPWR	47.88	583.72	27,946.97		1.07%			
International Business Machines Corp	IBM	929.40	232.41	216,001.06	0.60%	2.87%	0.02%	3.70%	0.02%
Johnson & Johnson	JNJ	2406.07	154.58	371,930.81	1.03%	3.36%	0.03%	7.00%	0.07%
Lululemon Athletica Inc	LULU	115.52	267.9	30,948.14					
McDonald's Corp	MCD	715.07	316.74	226,491.94	0.63%	2.24%	0.01%	8.53%	0.05%
Merck & Co Inc	MRK	2516.39	82.74	208,206.45	0.58%	3.92%	0.02%	14.62%	0.08%
3M Co	MMM	538.18	137.32	73,903.06	0.20%	2.13%	0.00%	6.18%	0.01%
American Water Works Co Inc	AWK	195.01	143.97	28,075.73	0.08%	2.13%	0.00%	6.60%	0.01%
Bank of America Corp	BAC	7602.80	39.69	301,755.07		2.62%			
Pfizer Inc	PFE	5671.45	22.92	129,989.74		7.50%		-1.66%	
Procter & Gamble Co/The	PG	2344.54	161.02	377,518.16	1.05%	2.63%	0.03%	3.76%	0.04%
AT&T Inc	T	7178.18	26.81	192,447.09	0.53%	4.14%	0.02%	3.95%	0.02%
Travelers Cos Inc/The	TRV	226.57	259.16	58,717.57	0.16%	1.70%	0.00%	2.22%	0.00%
RTX Corp	RTX	1335.95	125.22	167,288.13	0.46%	2.01%	0.01%	7.41%	0.03%
Analog Devices Inc	ADI	495.98	194.59	96,512.06	0.27%	2.04%	0.01%	11.79%	0.03%
Walmart Inc	WMT	8000.89	95.09	760,804.34	2.11%	0.99%	0.02%	7.43%	0.16%
Cisco Systems Inc	CSCO	3978.29	56.71	225,608.96	0.63%	2.89%	0.02%	4.69%	0.03%
Intel Corp	INTC	4362.00	20.05	87,458.10	0.24%			15.96%	0.04%
General Motors Co	GM	966.28	47.11	45,521.47	0.13%	1.02%	0.00%	8.79%	0.01%
Microsoft Corp	MSFT	7433.98	391.85	2,913,005.94	8.07%	0.85%	0.07%	13.09%	1.06%
Dollar General Corp	DG	219.95	93.56	20,578.25	0.06%	2.52%	0.00%	5.74%	0.00%
Cigna Group/The	CI	271.11	335.36	90,918.81	0.25%	1.80%	0.00%	5.07%	0.01%
Kinder Morgan Inc	KMI	2222.07	26.85	59,662.55		4.36%			
Citigroup Inc	C	1882.16	68.43	128,796.21		3.27%		23.17%	
American International Group Inc	AIG	583.77	81.22	47,414.05	0.13%	1.97%	0.00%	14.08%	0.02%
Altria Group Inc	MO	1686.34	58.26	98,246.25	0.27%	7.00%	0.02%	4.48%	0.01%
HCA Healthcare Inc	HCA	246.20	327.92	80,734.99	0.22%	0.88%	0.00%	9.24%	0.02%
International Paper Co	IP	527.88	47.35	24,994.92		3.91%		55.66%	
Hewlett Packard Enterprise Co	HPE	1313.58	16.24	21,332.51	0.06%	3.20%	0.00%	4.02%	0.00%
Abbott Laboratories	ABT	1734.32	128.85	223,467.57	0.62%	1.83%	0.01%	9.85%	0.06%
Aflac Inc	AFL	545.81	107.94	58,915.23	0.16%	2.15%	0.00%	4.80%	0.01%
Air Products and Chemicals Inc	APD	222.48	267.11	59,425.48	0.16%	2.68%	0.00%	6.28%	0.01%
Super Micro Computer Inc	SMCI	596.75	36.47	21,763.54					
Royal Caribbean Cruises Ltd	RCL	271.51	211.97	57,551.83	0.16%	1.42%	0.00%	19.67%	0.03%
Hess Corp	HES	309.31	132.34	40,934.05		1.51%			
Lennox International Inc	LII	35.48	527.31	18,711.51		0.87%			
Archer-Daniels-Midland Co	ADM	480.16	48.25	23,167.51	0.06%	4.23%	0.00%	5.97%	0.00%
Automatic Data Processing Inc	ADP	406.87	291.76	118,708.65	0.33%	2.11%	0.01%	9.07%	0.03%
Verisk Analytics Inc	VRSK	139.94	286.05	40,031.16	0.11%	0.63%	0.00%	8.98%	0.01%
AutoZone Inc	AZO	16.73	3609.33	60,379.25	0.17%			9.56%	0.02%
Linde PLC	LIN	472.91	448.4	212,053.57	0.59%	1.34%	0.01%	6.94%	0.04%
Avery Dennison Corp	AVY	78.97	170.75	13,483.44	0.04%	2.20%	0.00%	6.53%	0.00%
Enphase Energy Inc	ENPH	131.21	46.83	6,144.42				42.49%	
MSCI Inc	MSCI	77.60	535.36	41,544.81	0.12%	1.34%	0.00%	9.94%	0.01%
Ball Corp	BALL	282.38	50.56	14,277.08	0.04%	1.58%	0.00%	9.72%	0.00%
Axon Enterprise Inc	AXON	77.85	603.78	47,003.16				27.80%	
Dayforce Inc	DAY	158.26	57.81	9,149.15					
Carrier Global Corp	CARR	863.99	60.06	51,891.09	0.14%	1.50%	0.00%	13.16%	0.02%
Bank of New York Mellon Corp/The	BK	717.97	78.65	56,468.65	0.16%	2.39%	0.00%	13.11%	0.02%
Otis Worldwide Corp	OTIS	394.68	92.93	36,677.30		1.81%			
Baxter International Inc	BAX	512.92	30.22	15,500.57	0.04%	2.25%	0.00%	14.67%	0.01%
Becton Dickinson & Co	BDX	287.14	205.08	58,885.73	0.16%	2.03%	0.00%	9.31%	0.02%
Berkshire Hathaway Inc	BRK/B	1339.91	530.96	711,436.30					
Best Buy Co Inc	BBY	211.37	67.71	14,311.84	0.04%	5.61%	0.00%	5.78%	0.00%
Boston Scientific Corp	BSX	1479.07	101.9	150,717.25	0.42%			12.56%	0.05%
Bristol-Myers Squibb Co	BMY	2035.08	47.9	97,480.37		5.18%		80.00%	
Brown-Forman Corp	BF/B	303.54	33.96	10,308.22		2.67%		-2.71%	
Coterra Energy Inc	CTRA	764.10	25.37	19,385.12		3.47%		32.16%	
Hilton Worldwide Holdings Inc	HLT	239.61	219.62	52,624.03	0.15%	0.27%	0.00%	11.85%	0.02%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Carnival Corp	CCL	1166.61	18.6	21,698.89				22.81%	
Builders FirstSource Inc	BLDR	113.74	121.35	13,802.69	0.04%			4.59%	0.00%
UDR Inc	UDR	331.13	41.3	13,675.81	0.04%	4.16%	0.00%	1.98%	0.00%
Clorox Co/The	CLX	123.19	138.27	17,033.46	0.05%	3.53%	0.00%	8.97%	0.00%
Paycom Software Inc	PAYC	57.85	227.6	13,167.19	0.04%	0.66%	0.00%	7.40%	0.00%
CMS Energy Corp	CMS	299.12	72.18	21,590.75	0.06%	3.01%	0.00%	7.59%	0.00%
Colgate-Palmolive Co	CL	810.42	93.91	76,106.55	0.21%	2.21%	0.00%	5.69%	0.01%
EPAM Systems Inc	EPAM	57.27	159.12	9,112.83	0.03%			7.68%	0.00%
Conagra Brands Inc	CAG	477.36	24.45	11,671.51		5.73%		-3.22%	
Airbnb Inc	ABNB	440.00	122.51	53,904.66	0.15%			10.66%	0.02%
Consolidated Edison Inc	ED	360.20	110.45	39,784.12	0.11%	3.08%	0.00%	4.84%	0.01%
Corning Inc	GLW	856.78	44.18	37,852.41	0.10%	2.54%	0.00%	17.92%	0.02%
GoDaddy Inc	GDDY	142.44	183.4	26,122.67					
Cummins Inc	CMI	137.74	293.26	40,394.39	0.11%	2.48%	0.00%	8.31%	0.01%
Caesars Entertainment Inc	CZR	208.86	28.44	5,940.03				82.46%	
Danaher Corp	DHR	715.67	197.14	141,087.10	0.39%	0.65%	0.00%	8.67%	0.03%
Target Corp	TGT	455.58	96.58	43,999.57	0.12%	4.64%	0.01%	6.49%	0.01%
Williams-Sonoma Inc	WSM	123.51	151.19	18,673.40	0.05%	1.75%	0.00%	4.50%	0.00%
Deere & Co	DE	271.41	459.3	124,660.42		1.41%		-0.83%	
Dominion Energy Inc	D	852.22	52.95	45,124.79		5.04%		23.10%	
Dover Corp	DOV	137.10	169.01	23,172.01	0.06%	1.22%	0.00%	10.05%	0.01%
Alliant Energy Corp	LNT	256.87	60.74	15,602.48	0.04%	3.34%	0.00%	6.19%	0.00%
Steel Dynamics Inc	STLD	149.90	127.34	19,087.86	0.05%	1.57%	0.00%	14.00%	0.01%
Duke Energy Corp	DUK	777.02	119.85	93,126.05	0.26%	3.49%	0.01%	8.00%	0.02%
Regency Centers Corp	REG	181.53	71.42	12,964.58	0.04%	3.95%	0.00%	4.59%	0.00%
Eaton Corp PLC	ETN	391.77	288.82	113,150.83	0.31%	1.44%	0.00%	11.80%	0.04%
Ecolab Inc	ECL	283.63	238.14	67,544.26	0.19%	1.09%	0.00%	11.63%	0.02%
Revvity Inc	RVTY	120.15	94.29	11,328.69	0.03%	0.30%	0.00%	8.52%	0.00%
Dell Technologies Inc	DELL	358.71	94.89	34,038.03	0.09%	2.21%	0.00%	12.40%	0.01%
Emerson Electric Co	EMR	563.90	105.28	59,367.39	0.16%	2.00%	0.00%	8.02%	0.01%
EOG Resources Inc	EOG	551.54	113.07	62,363.13	0.17%	3.45%	0.01%	1.15%	0.00%
Aon PLC	AON	216.00	335.85	72,543.97	0.20%	0.89%	0.00%	10.68%	0.02%
Entergy Corp	ETR	446.34	84.61	37,764.90	0.10%	2.84%	0.00%	7.73%	0.01%
Equifax Inc	EFX	124.20	256.48	31,854.57	0.09%	0.78%	0.00%	12.80%	0.01%
EQT Corp	EQT	598.63	50.24	30,074.97		1.25%		51.24%	
IQVIA Holdings Inc	IQV	176.32	150.28	26,496.62	0.07%			8.49%	0.01%
Gartner Inc	IT	77.06	416.09	32,063.56					
FedEx Corp	FDX	239.60	211.56	50,689.55	0.14%	2.61%	0.00%	11.22%	0.02%
Brown & Brown Inc	BRO	286.63	114.44	32,801.66	0.09%	0.52%	0.00%	9.12%	0.01%
Ford Motor Co	F	3905.70	10.04	39,213.18	0.11%	1.49%	0.00%	0.18%	0.00%
NextEra Energy Inc	NEE	2058.63	66.09	136,054.93	0.38%	3.43%	0.01%	7.19%	0.03%
Franklin Resources Inc	BEN	525.40	18.72	9,835.45		6.84%			
Garmin Ltd	GRMN	192.64	198.96	38,327.90	0.11%	1.81%	0.00%	11.34%	0.01%
Freeport-McMoRan Inc	FCX	1437.07	37.35	53,674.68	0.15%	1.61%	0.00%	16.33%	0.02%
Expand Energy Corp	EXE	237.97	105.3	25,058.67		2.18%			
Dexcom Inc	DXCM	392.11	71.66	28,098.42	0.08%			19.18%	0.01%
General Dynamics Corp	GD	268.40	271.97	72,995.70	0.20%	2.21%	0.00%	13.82%	0.03%
General Mills Inc	GIS	547.60	56.14	30,742.29		4.28%		-2.42%	
Genuine Parts Co	GPC	138.79	116.64	16,188.42		3.53%			
Atmos Energy Corp	ATO	158.73	158.14	25,101.28	0.07%	2.20%	0.00%	7.27%	0.01%
WW Grainger Inc	GWW	48.17	1013.87	48,839.57	0.14%	0.81%	0.00%	5.89%	0.01%
Halliburton Co	HAL	859.72	20.85	17,925.06		3.26%		-2.39%	
L3Harris Technologies Inc	LHX	186.95	216.08	40,395.21	0.11%	2.22%	0.00%	12.47%	0.01%
Healthpeak Properties Inc	DOC	698.60	17.83	12,455.97	0.03%	6.84%	0.00%	4.91%	0.00%
Insulet Corp	PODD	70.23	260.71	18,308.65				24.42%	
Fortive Corp	FTV	339.88	68.92	23,424.27	0.06%	0.46%	0.00%	7.33%	0.00%
Hershey Co/The	HSY	147.95	163.28	24,157.19		3.36%		-9.26%	
Synchrony Financial	SYF	380.65	51.42	19,573.06	0.05%	2.33%	0.00%	17.55%	0.01%
Hormel Foods Corp	HRL	549.91	29.7	16,332.40	0.05%	3.91%	0.00%	5.97%	0.00%
Arthur J Gallagher & Co	AJG	255.73	322.3	82,423.33		0.81%			
Mondelez International Inc	MDLZ	1295.54	65.59	84,974.14	0.24%	2.87%	0.01%	0.40%	0.00%
CenterPoint Energy Inc	CNP	652.73	38.19	24,927.63	0.07%	2.30%	0.00%	8.05%	0.01%
Humana Inc	HUM	120.69	264.4	31,911.13	0.09%	1.34%	0.00%	6.88%	0.01%
Willis Towers Watson PLC	WTW	99.15	302.19	29,962.08	0.08%	1.22%	0.00%	6.91%	0.01%
Illinois Tool Works Inc	ITW	293.37	239.5	70,261.15	0.19%	2.51%	0.00%	1.21%	0.00%
CDW Corp/DE	CDW	131.77	157.95	20,812.55	0.06%	1.58%	0.00%	6.38%	0.00%
Trane Technologies PLC	TT	223.18	347.97	77,658.53	0.22%	1.08%	0.00%	9.79%	0.02%
Interpublic Group of Cos Inc/The	IPG	369.73	24.56	9,080.68		5.37%			
International Flavors & Fragrances Inc	IFF	255.74	76.24	19,497.24	0.05%	2.10%	0.00%	4.29%	0.00%
Generac Holdings Inc	GNRC	59.61	112.89	6,729.83	0.02%			19.54%	0.00%
NXP Semiconductors NV	NXPI	253.62	193.55	49,088.17	0.14%	2.10%	0.00%	4.62%	0.01%
Kellanova	K	345.22	82.62	28,521.74	0.08%	2.76%	0.00%	4.55%	0.00%
Broadridge Financial Solutions Inc	BR	117.02	237.72	27,817.68		1.48%			
Kimberly-Clark Corp	KMB	331.82	131.61	43,670.31	0.12%	3.83%	0.00%	3.40%	0.00%
Kimco Realty Corp	KIM	679.50	20.35	13,827.80	0.04%	4.91%	0.00%	3.40%	0.00%
Oracle Corp	ORCL	2804.23	138.49	388,358.37	1.08%	1.44%	0.02%	8.44%	0.09%
Kroger Co/The	KR	660.89	70	46,262.54	0.13%	1.83%	0.00%	6.11%	0.01%
Lennar Corp	LEN	232.18	107.63	24,990.01		1.86%		-4.18%	
Eli Lilly & Co	LLY	947.99	884.54	838,534.32		0.68%		21.00%	
Charter Communications Inc	CHTR	140.36	373.65	52,447.09	0.15%			19.22%	0.03%
Loews Corp	L	210.34	85.27	17,935.85		0.29%			
Lowe's Cos Inc	LOW	559.71	220.91	123,644.61	0.34%	2.08%	0.01%	6.05%	0.02%
Hubbell Inc	HUBB	53.57	359.84	19,277.84		1.47%			
IDEX Corp	IEX	75.54	173	13,069.13		1.60%			
Marsh & McLennan Cos Inc	MMC	492.73	219.24	108,025.63	0.30%	1.49%	0.00%	8.59%	0.03%
Masco Corp	MAS	210.94	60.42	12,745.12	0.04%	2.05%	0.00%	7.38%	0.00%
S&P Global Inc	SPGI	313.84	480	150,643.23	0.42%	0.80%	0.00%	14.39%	0.06%
Medtronic PLC	MDT	1282.54	84.16	107,938.86	0.30%	3.33%	0.01%	6.49%	0.02%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Viatris Inc	VTRS	1193.69	8.13	9,704.69		5.90%		-3.79%	
CVS Health Corp	CVS	1262.38	65.32	82,458.91	0.23%	4.07%	0.01%	14.47%	0.03%
DuPont de Nemours Inc	DD	418.50	65.69	27,491.17	0.08%	2.50%	0.00%	5.58%	0.00%
Micron Technology Inc	MU	1117.57	79.78	89,159.86		0.58%			
Motorola Solutions Inc	MSI	166.96	430.22	71,831.06	0.20%	1.01%	0.00%	7.04%	0.01%
Cboe Global Markets Inc	CBOE	104.71	213.59	22,365.54	0.06%	1.18%	0.00%	9.71%	0.01%
Newmont Corp	NEM	1113.00	53.94	60,035.05	0.17%	1.85%	0.00%	14.18%	0.02%
NIKE Inc	NKE	1178.10	57.62	67,882.28		2.78%		-6.80%	
NiSource Inc	NI	470.61	39.45	18,565.38	0.05%	2.84%	0.00%	7.43%	0.00%
Norfolk Southern Corp	NSC	225.44	221.71	49,983.08	0.14%	2.44%	0.00%	11.89%	0.02%
Principal Financial Group Inc	PFG	224.97	73.46	16,526.42	0.05%	4.14%	0.00%	11.78%	0.01%
Eversource Energy	ES	367.08	57.86	21,239.36	0.06%	5.20%	0.00%	4.47%	0.00%
Northrop Grumman Corp	NOC	143.93	473.2	68,106.81	0.19%	1.74%	0.00%	4.19%	0.01%
Wells Fargo & Co	WFC	3265.16	69.73	227,679.53	0.63%	2.29%	0.01%	14.29%	0.09%
Nucor Corp	NUE	230.75	115.72	26,701.94		1.90%		20.02%	
Occidental Petroleum Corp	OXY	939.78	40.36	37,929.62		2.38%			
Omnicom Group Inc	OMC	195.11	74.92	14,617.60		3.74%			
ONEOK Inc	OKE	624.62	86.31	53,911.09	0.15%	4.77%	0.01%	0.13%	0.00%
Raymond James Financial Inc	RJF	204.91	137.37	28,148.49	0.08%	1.46%	0.00%	8.07%	0.01%
PG&E Corp	PCG	2675.43	17.14	45,856.85		0.58%			
Parker-Hannifin Corp	PH	128.76	598.02	77,003.95	0.21%	1.20%	0.00%	7.05%	0.02%
Rollins Inc	ROL	484.65	55.31	26,805.80		1.19%			
PPL Corp	PPL	739.05	35.93	26,554.12	0.07%	3.03%	0.00%	6.92%	0.01%
Aptiv PLC	APTV	229.45	55.93	12,832.94	0.04%			15.01%	0.01%
ConocoPhillips	COP	1264.17	91.72	115,949.25		3.40%			
PulteGroup Inc	PHM	200.43	101.88	20,419.52		0.86%		-1.13%	
Pinnacle West Capital Corp	PNW	119.21	93.75	11,176.40	0.03%	3.82%	0.00%	2.12%	0.00%
PNC Financial Services Group Inc/The	PNC	395.75	158.46	62,710.48	0.17%	4.04%	0.01%	7.49%	0.01%
PPG Industries Inc	PPG	226.97	102.57	23,280.82	0.06%	2.65%	0.00%	5.53%	0.00%
DoorDash Inc	DASH	398.14	187.76	74,755.03					
Progressive Corp/The	PGR	586.24	265.01	155,358.43	0.43%	0.15%	0.00%	14.70%	0.06%
Veralto Corp	VLTO	248.05	92.31	22,897.66		0.48%			
Public Service Enterprise Group Inc	PEG	498.56	81.03	40,398.44	0.11%	3.11%	0.00%	9.40%	0.01%
Cooper Cos Inc/The	COO	199.98	80.89	16,176.48	0.04%			9.91%	0.00%
Edison International	EIX	385.02	57.96	22,315.96		5.71%			
Schlumberger NV	SLB	1360.16	34.52	46,952.78		3.30%		-0.49%	
Charles Schwab Corp/The	SCHW	1815.92	79.94	145,164.48	0.40%	1.35%	0.01%	19.69%	0.08%
Sherwin-Williams Co/The	SHW	251.51	331.62	83,405.80	0.23%	0.95%	0.00%	5.49%	0.01%
West Pharmaceutical Services Inc	WST	71.85	214.55	15,414.42	0.04%	0.39%	0.00%	6.27%	0.00%
J M Smucker Co/The	SJM	106.42	115.23	12,262.39		3.75%			
Snap-on Inc	SNA	52.29	308.76	16,145.38	0.04%	2.77%	0.00%	3.46%	0.00%
AMETEK Inc	AME	230.75	166.69	38,463.20	0.11%	0.74%	0.00%	8.14%	0.01%
Uber Technologies Inc	UBER	2091.26	77.75	162,595.32				-6.02%	
Southern Co/The	SO	1100.19	90.43	99,490.51	0.28%	3.27%	0.01%	6.37%	0.02%
Truist Financial Corp	TFC	1305.39	37.67	49,174.07	0.14%	5.52%	0.01%	7.53%	0.01%
Southwest Airlines Co	LUV	569.87	26.49	15,095.75		2.72%		57.29%	
W R Berkley Corp	WRB	379.31	70.48	26,733.97	0.07%	0.45%	0.00%	6.85%	0.01%
Stanley Black & Decker Inc	SWK	154.54	61.58	9,516.42		5.33%			
Public Storage	PSA	175.42	290.91	51,030.70	0.14%	4.12%	0.01%	3.64%	0.01%
Arista Networks Inc	ANET	1255.63	77.91	97,825.78	0.27%			14.64%	0.04%
Sysco Corp	SYY	489.23	70.93	34,701.06		3.05%			
Corteva Inc	CTVA	683.01	61.47	41,984.91	0.12%	1.11%	0.00%	15.89%	0.02%
Texas Instruments Inc	TXN	908.47	162.86	147,953.76	0.41%	3.34%	0.01%	11.66%	0.05%
Textron Inc	TXT	180.54	68.42	12,352.46	0.03%	0.12%	0.00%	10.03%	0.00%
Thermo Fisher Scientific Inc	TMO	377.49	424.24	160,147.33	0.44%	0.41%	0.00%	8.08%	0.04%
TJX Cos Inc/The	TJX	1117.10	126.56	141,380.24	0.39%	1.34%	0.01%	7.62%	0.03%
Globe Life Inc	GL	83.24	122.96	10,235.53		0.88%			
Johnson Controls International plc	JCI	660.14	81.07	53,517.48	0.15%	1.83%	0.00%	9.17%	0.01%
Ulta Beauty Inc	ULTA	45.15	383.67	17,321.89	0.05%			3.98%	0.00%
Union Pacific Corp	UNP	597.48	213.29	127,435.57	0.35%	2.51%	0.01%	9.19%	0.03%
Keysight Technologies Inc	KEYS	172.81	144.01	24,886.44	0.07%			12.64%	0.01%
UnitedHealth Group Inc	UNH	910.22	418.64	381,056.09	1.06%	2.01%	0.02%	6.78%	0.07%
Blackstone Inc	BX	729.42	132.86	96,910.20		2.80%		21.63%	
Ventas Inc	VTR	437.70	68.16	29,833.48	0.08%	2.82%	0.00%	9.17%	0.01%
Labcorp Holdings Inc	LH	83.67	228.31	19,102.32	0.05%	1.26%	0.00%	10.01%	0.01%
Vulcan Materials Co	VMC	132.10	247.04	32,634.28	0.09%	0.79%	0.00%	12.90%	0.01%
Weyerhaeuser Co	WY	725.85	24.81	18,008.31		3.39%			
Williams Cos Inc/The	WMB	1220.69	59.03	72,057.14		3.39%			
Constellation Energy Corp	CEG	315.12	222.99	70,268.82	0.19%	0.70%	0.00%	12.00%	0.02%
WEC Energy Group Inc	WEC	319.09	107.73	34,375.48	0.10%	3.31%	0.00%	7.53%	0.01%
Adobe Inc	ADBE	426.20	367.72	156,722.26	0.43%			13.49%	0.06%
Vistra Corp	VST	340.16	126.64	43,077.49	0.12%	0.71%	0.00%	3.86%	0.00%
AES Corp/The	AES	711.90	10.05	7,154.60	0.02%	7.00%	0.00%	3.75%	0.00%
Expeditors International of Washington Inc	EXPD	137.76	108.58	14,957.62	0.04%	1.34%	0.00%	4.35%	0.00%
Amgen Inc	AMGN	537.65	280.84	150,993.80	0.42%	3.39%	0.01%	5.13%	0.02%
Apple Inc	AAPL	15022.07	209.28	3,143,819.44	8.71%	0.48%	0.04%	13.46%	1.17%
Autodesk Inc	ADSK	213.00	269.93	57,495.09	0.16%			14.19%	0.02%
Cintas Corp	CTAS	403.79	208.4	84,149.20	0.23%	0.75%	0.00%	14.37%	0.03%
Comcast Corp	CMCSA	3724.26	33.9	126,252.40	0.35%	3.89%	0.01%	3.20%	0.01%
Molson Coors Beverage Co	TAP	190.29	56.8	10,808.59	0.03%	3.31%	0.00%	8.44%	0.00%
KLA Corp	KLAC	132.89	694.61	92,304.47	0.26%	0.98%	0.00%	15.45%	0.04%
Marriott International Inc/MD	MAR	275.37	236.2	65,043.05	0.18%	1.07%	0.00%	9.71%	0.02%
Fiserv Inc	FI	554.43	177.53	98,428.64	0.27%			15.52%	0.04%
McCormick & Co Inc/MD	MKC	252.68	74.54	18,834.90	0.05%	2.41%	0.00%	6.37%	0.00%
PACCAR Inc	PCAR	524.93	91.89	48,236.26	0.13%	1.44%	0.00%	1.46%	0.00%
Costco Wholesale Corp	COST	443.68	977.16	433,549.63	1.20%	0.53%	0.01%	8.86%	0.11%
Stryker Corp	SYK	381.69	365.06	139,339.33	0.39%	0.92%	0.00%	9.83%	0.04%
Tyson Foods Inc	TSN	286.19	60.62	17,348.56		3.30%		21.06%	

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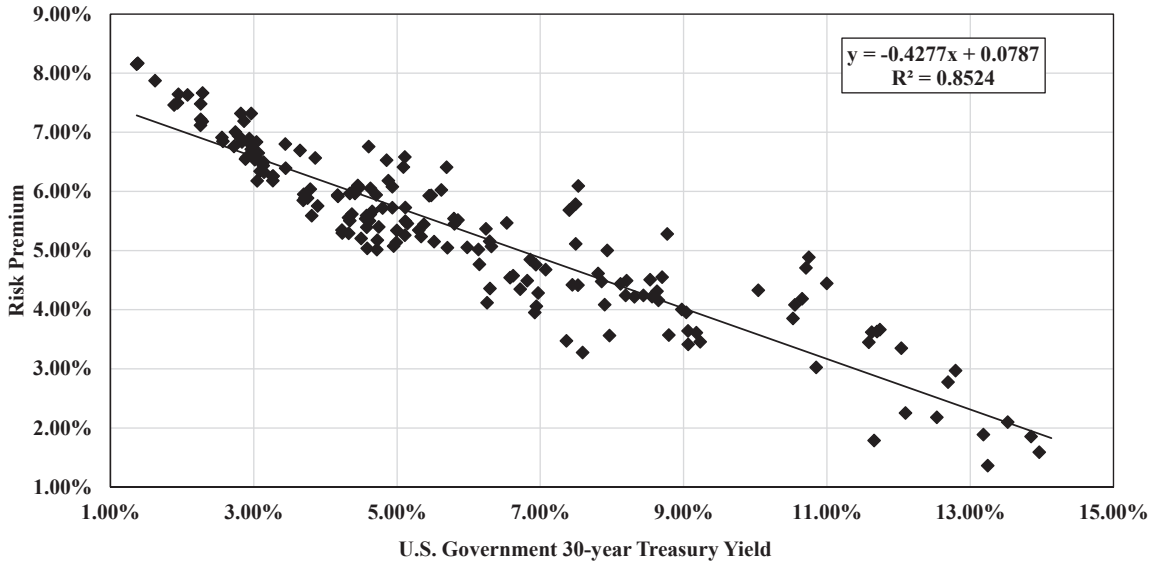
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Lamb Weston Holdings Inc	LW	141.12	51.94	7,329.55		2.85%		-12.10%	
Applied Materials Inc	AMAT	812.44	151.55	123,125.41	0.34%	1.21%	0.00%	10.64%	0.04%
Cardinal Health Inc	CAH	241.57	137.56	33,230.09	0.09%	1.47%	0.00%	9.07%	0.01%
Cincinnati Financial Corp	CINF	156.56	133.69	20,931.14	0.06%	2.60%	0.00%	2.44%	0.00%
Paramount Global	PARA	630.01	11.73	7,389.99		1.71%			
DR Horton Inc	DHI	307.18	124.56	38,262.50	0.11%	1.28%	0.00%	1.58%	0.00%
Electronic Arts Inc	EA	260.62	146.6	38,206.54	0.11%	0.52%	0.00%	5.98%	0.01%
Erie Indemnity Co	ERIE	46.19	361.85	16,713.51		1.51%			
Fair Isaac Corp	FICO	24.42	1952.31	47,671.78				26.88%	
Fastenal Co	FAST	573.62	80.73	46,308.39	0.13%	2.18%	0.00%	10.52%	0.01%
M&T Bank Corp	MTB	164.29	167.39	27,500.56	0.08%	3.23%	0.00%	11.79%	0.01%
Xcel Energy Inc	XEL	576.76	69	39,796.48	0.11%	3.30%	0.00%	8.05%	0.01%
Fifth Third Bancorp	FITB	668.10	35.28	23,570.53		4.20%			
Gilead Sciences Inc	GILD	1245.16	103.17	128,463.45		3.06%		21.81%	
Hasbro Inc	HAS	139.89	60.99	8,532.09	0.02%	4.59%	0.00%	8.59%	0.00%
Huntington Bancshares Inc/OH	HBAN	1460.75	14.4	21,034.86	0.06%	4.31%	0.00%	12.92%	0.01%
Welltower Inc	WELL	651.54	146.96	95,749.79	0.27%	1.82%	0.00%	16.50%	0.04%
Biogen Inc	BIIB	146.37	118.84	17,395.20	0.05%			2.47%	0.00%
Northern Trust Corp	NTRS	194.97	91.59	17,857.45	0.05%	3.28%	0.00%	9.64%	0.00%
Packaging Corp of America	PKG	89.93	184.82	16,620.52		2.71%			
Paychex Inc	PAYX	360.19	143.21	51,582.91	0.14%	2.74%	0.00%	6.24%	0.01%
QUALCOMM Inc	QCOM	1106.00	148.56	164,307.36	0.46%	2.40%	0.01%	15.26%	0.07%
Ross Stores Inc	ROST	328.83	139.71	45,941.43	0.13%	1.16%	0.00%	6.48%	0.01%
IDEXX Laboratories Inc	IDXX	81.04	437.44	35,449.72	0.10%			12.52%	0.01%
Starbucks Corp	SBUX	1135.90	83.81	95,199.78	0.26%	2.91%	0.01%	10.29%	0.03%
KeyCorp	KEY	1095.72	14.72	16,128.96	0.04%	5.57%	0.00%	19.35%	0.01%
Fox Corp	FOXA	217.85	49.35	10,750.74	0.03%	1.09%	0.00%	8.98%	0.00%
Fox Corp	FOX	235.58	45.79	10,787.26	0.03%	1.18%	0.00%	8.98%	0.00%
State Street Corp	STT	288.59	87.38	25,217.08	0.07%	3.48%	0.00%	10.63%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	443.22	17.23	7,636.67	0.02%			18.95%	0.00%
US Bancorp	USB	1558.01	39.92	62,195.78	0.17%	5.01%	0.01%	10.38%	0.02%
A O Smith Corp	AOS	117.66	64.99	7,646.66		2.09%			
Gen Digital Inc	GEN	616.30	25.26	15,567.77	0.04%	1.98%	0.00%	11.23%	0.00%
T Rowe Price Group Inc	TROW	222.24	88.44	19,655.12		5.74%		-3.02%	
Waste Management Inc	WM	402.33	228.31	91,856.51	0.25%	1.45%	0.00%	10.67%	0.03%
Constellation Brands Inc	STZ	177.99	185.35	32,991.01	0.09%	2.20%	0.00%	1.36%	0.00%
Invesco Ltd	IVZ	447.41	13.93	6,232.47	0.02%	6.03%	0.00%	3.37%	0.00%
Intuit Inc	INTU	279.56	624.12	174,480.24	0.48%	0.67%	0.00%	13.37%	0.06%
Morgan Stanley	MS	1608.51	116.01	186,602.99	0.52%	3.19%	0.02%	10.29%	0.05%
Microchip Technology Inc	MCHP	537.82	46.89	25,218.33		3.88%		-33.30%	
Crowdstrike Holdings Inc	CRWD	247.87	424.88	105,316.46				24.67%	
Chubb Ltd	CB	400.69	279.11	111,835.22	0.31%	1.30%	0.00%	4.24%	0.01%
Hologic Inc	HOLX	225.72	58.02	13,096.45	0.04%			8.86%	0.00%
Citizens Financial Group Inc	CFG	437.13	37.06	16,200.18		4.53%		23.45%	
Jabil Inc	JBL	107.35	146.92	15,771.18	0.04%	0.22%	0.00%	12.83%	0.01%
O'Reilly Automotive Inc	ORLY	57.24	1347	77,102.97	0.21%			9.80%	0.02%
Allstate Corp/The	ALL	265.14	192.91	51,147.98	0.14%	2.07%	0.00%	12.93%	0.02%
Equity Residential	EQR	379.84	68.53	26,030.48	0.07%	4.04%	0.00%	4.03%	0.00%
Keurig Dr Pepper Inc	KDP	1358.18	34.4	46,721.33	0.13%	2.67%	0.00%	6.20%	0.01%
Host Hotels & Resorts Inc	HST	698.67	13.88	9,697.56		5.76%		-2.44%	
Incyte Corp	INCY	193.52	59.16	11,448.90					
Simon Property Group Inc	SPG	326.24	156.66	51,109.29	0.14%	5.36%	0.01%	1.29%	0.00%
Eastman Chemical Co	EMN	115.46	75.84	8,756.50	0.02%	4.38%	0.00%	6.76%	0.00%
AvalonBay Communities Inc	AVB	142.37	205.76	29,293.77	0.08%	3.40%	0.00%	5.26%	0.00%
Prudential Financial Inc	PRU	354.43	102.9	36,470.55	0.10%	5.25%	0.01%	7.66%	0.01%
United Parcel Service Inc	UPS	733.69	97.91	71,835.27	0.20%	6.70%	0.01%	7.91%	0.02%
Walgreens Boots Alliance Inc	WBA	864.74	11.01	9,520.76				-21.88%	
STERIS PLC	STE	98.25	225	22,106.43		1.01%			
McKesson Corp	MCK	125.33	695	87,101.83	0.24%	0.41%	0.00%	13.47%	0.03%
Lockheed Martin Corp	LMT	234.30	477.64	111,909.12	0.31%	2.76%	0.01%	11.65%	0.04%
Cencora Inc	COR	193.71	285.9	55,382.43	0.15%	0.77%	0.00%	9.83%	0.02%
Capital One Financial Corp	COF	381.48	182.73	69,707.74	0.19%	1.31%	0.00%	14.96%	0.03%
The Campbell's Company	CPB	298.18	36.29	10,821.02	0.03%	4.30%	0.00%	2.22%	0.00%
Waters Corp	WAT	59.50	337.89	20,103.03	0.06%			7.42%	0.00%
Nordson Corp	NDSN	56.91	188.22	10,711.93		1.66%			
Dollar Tree Inc	DLTR	215.08	80.57	17,329.24	0.05%			8.42%	0.00%
Darden Restaurants Inc	DRI	117.03	199.1	23,299.93	0.06%	2.81%	0.00%	9.10%	0.01%
Evergy Inc	EVRG	229.75	67.88	15,595.15	0.04%	3.93%	0.00%	5.71%	0.00%
Match Group Inc	MTCH	246.68	30.07	7,417.62	0.02%	2.53%	0.00%	9.22%	0.00%
NVR Inc	NVR	2.97	7071.42	20,995.05	0.06%			4.50%	0.00%
NetApp Inc	NTAP	203.41	88.45	17,991.75	0.05%	2.35%	0.00%	8.16%	0.00%
Old Dominion Freight Line Inc	ODFL	212.15	146.74	31,130.46	0.09%	0.76%	0.00%	7.72%	0.01%
DaVita Inc	DVA	76.86	139.56	10,727.05	0.03%			10.03%	0.00%
Hartford Insurance Group Inc/The	HIG	284.10	118.76	33,740.07	0.09%	1.75%	0.00%	9.03%	0.01%
Iron Mountain Inc	IRM	294.97	87.72	25,874.61		3.58%			
Estee Lauder Cos Inc/The	EL	234.17	59.39	13,907.56	0.04%	2.36%	0.00%	8.85%	0.00%
Cadence Design Systems Inc	CDNS	274.31	289.63	79,449.45	0.22%			14.79%	0.03%
Tyler Technologies Inc	TYL	43.12	524.64	22,624.34					
Universal Health Services Inc	UHS	57.95	171.68	9,949.19	0.03%	0.47%	0.00%	11.19%	0.00%
Skyworks Solutions Inc	SWKS	153.57	61.52	9,447.92		4.55%		-9.02%	
Quest Diagnostics Inc	DGX	111.64	173.76	19,397.78	0.05%	1.84%	0.00%	8.44%	0.00%
Rockwell Automation Inc	ROK	113.07	248.38	28,085.06	0.08%	2.11%	0.00%	10.92%	0.01%
Kraft Heinz Co/The	KHC	1193.40	29.49	35,193.32		5.43%		-3.61%	
American Tower Corp	AMT	468.12	210.82	98,688.60		3.23%		23.46%	
Regeneron Pharmaceuticals Inc	REGN	106.95	602.64	64,453.26	0.18%	0.58%	0.00%	7.95%	0.01%
Amazon.com Inc	AMZN	10612.36	188.99	2,005,630.67	5.56%			11.42%	0.63%
Jack Henry & Associates Inc	JKHY	72.90	170.93	12,460.40	0.03%	1.36%	0.00%	9.25%	0.00%
Ralph Lauren Corp	RL	39.88	219.96	8,772.65	0.02%	1.50%	0.00%	13.79%	0.00%

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
BXP Inc	BXP	158.21	65.85	10,418.10	0.03%	5.95%	0.00%	1.55%	0.00%
Amphenol Corp	APH	1211.78	75.85	91,913.76	0.25%	0.87%	0.00%	18.81%	0.05%
Howmet Aerospace Inc	HWM	404.46	135.76	54,910.00	0.15%	0.29%	0.00%	12.69%	0.02%
Valero Energy Corp	VLO	313.21	113.87	35,664.78	0.10%	3.97%	0.00%	4.67%	0.00%
Synopsys Inc	SNPS	154.62	446.62	69,056.42	0.19%			13.35%	0.03%
CH Robinson Worldwide Inc	CHRW	118.23	89.75	10,610.88	0.03%	2.76%	0.00%	16.60%	0.00%
Accenture PLC	ACN	626.03	293.39	183,669.72	0.51%	2.02%	0.01%	7.12%	0.04%
TransDigm Group Inc	TDG	56.08	1378.13	77,291.86	0.21%			13.51%	0.03%
Yum! Brands Inc	YUM	278.50	147.3	41,023.05	0.11%	1.93%	0.00%	11.00%	0.01%
Prologis Inc	PLD	926.18	102.24	94,692.13	0.26%	3.95%	0.01%	5.83%	0.02%
FirstEnergy Corp	FE	577.13	42.34	24,435.52	0.07%	4.20%	0.00%	0.83%	0.00%
VeriSign Inc	VRSN	93.90	272.79	25,614.98		1.13%			
Quanta Services Inc	PWR	148.26	287.34	42,602.07	0.12%	0.14%	0.00%	13.20%	0.02%
Henry Schein Inc	HSIC	122.51	65.17	7,984.10	0.02%			5.92%	0.00%
Ameren Corp	AEE	270.16	98.28	26,551.10		2.89%			
ANSYS Inc	ANSS	87.65	320.68	28,108.17					
FactSet Research Systems Inc	FDS	37.95	424.47	16,107.39		0.98%			
NVIDIA Corp	NVDA	24400.00	111.01	2,708,644.00		0.04%		29.34%	
Cognizant Technology Solutions Corp	CTSH	492.94	72.17	35,575.43	0.10%	1.72%	0.00%	6.14%	0.01%
Intuitive Surgical Inc	ISRG	358.42	514.59	184,438.45	0.51%			13.49%	0.07%
Take-Two Interactive Software Inc	TTWO	176.50	225.38	39,778.60				60.65%	
Republic Services Inc	RSG	312.50	243.56	76,111.77	0.21%	0.95%	0.00%	9.36%	0.02%
eBay Inc	EBAY	466.00	67.83	31,608.78	0.09%	1.71%	0.00%	7.84%	0.01%
Goldman Sachs Group Inc/The	GS	310.79	544.86	169,337.25	0.47%	2.20%	0.01%	13.24%	0.06%
SBA Communications Corp	SBAC	108.03	222.09	23,991.97	0.07%	2.00%	0.00%	6.59%	0.00%
Sempra	SRE	651.91	74.68	48,684.89	0.13%	3.45%	0.00%	7.02%	0.01%
Moody's Corp	MCO	179.90	438.62	78,907.74	0.22%	0.86%	0.00%	11.80%	0.03%
ON Semiconductor Corp	ON	422.05	39.63	16,725.82				-0.17%	
Booking Holdings Inc	BKNG	32.70	4838.44	158,212.83	0.44%	0.79%	0.00%	15.92%	0.07%
F5 Inc	FFIV	57.65	270.03	15,567.84	0.04%			7.07%	0.00%
Akamai Technologies Inc	AKAM	146.11	79.79	11,658.50					
Charles River Laboratories International Inc	CRL	49.12	114.66	5,631.61	0.02%			2.77%	0.00%
MarketAxess Holdings Inc	MKTX	37.20	219	8,147.10	0.02%	1.39%	0.00%	0.50%	0.00%
Devon Energy Corp	DVN	643.33	31.35	20,168.37	0.06%	3.06%	0.00%	11.01%	0.01%
Bio-Techne Corp	TECH	158.09	50.24	7,942.33		0.64%			
Alphabet Inc	GOOGL	5820.00	161.96	942,607.20	2.61%	0.52%	0.01%	12.96%	0.34%
Allegion plc	ALLE	86.05	136.49	11,744.87	0.03%	1.49%	0.00%	4.57%	0.00%
Netflix Inc	NFLX	425.57	1101.53	468,779.52				25.26%	
Agilent Technologies Inc	A	285.10	106.28	30,300.72	0.08%	0.93%	0.00%	8.80%	0.01%
Warner Bros Discovery Inc	WBD	2473.84	8.59	21,250.25				41.11%	
Trimble Inc	TRMB	238.58	61.71	14,722.99					
Elevance Health Inc	ELV	225.93	421.68	95,272.10	0.26%	1.62%	0.00%	10.65%	0.03%
CME Group Inc	CME	360.38	266.3	95,969.08	0.27%	1.88%	0.00%	7.82%	0.02%
Juniper Networks Inc	JNPR	334.28	35.6	11,900.26	0.03%	2.47%	0.00%	12.36%	0.00%
DTE Energy Co	DTE	207.52	134.76	27,965.09	0.08%	3.24%	0.00%	5.80%	0.00%
Nasdaq Inc	NDAQ	574.12	75.36	43,265.81	0.12%	1.43%	0.00%	12.82%	0.02%
Philip Morris International Inc	PM	1556.52	170.24	264,981.48	0.73%	3.17%	0.02%	11.22%	0.08%
Ingersoll Rand Inc	IR	403.08	74.98	30,223.18		0.11%			
Salesforce Inc	CRM	959.47	267.85	256,995.00	0.71%	0.62%	0.00%	12.19%	0.09%
Roper Technologies Inc	ROP	107.39	557.7	59,888.73		0.59%			
Huntington Ingalls Industries Inc	HII	39.24	226.05	8,869.20	0.02%	2.39%	0.00%	13.85%	0.00%
MetLife Inc	MET	681.23	75.19	51,221.54	0.14%	3.02%	0.00%	12.97%	0.02%
Tapestry Inc	TPR	207.02	68.88	14,259.23	0.04%	2.03%	0.00%	9.55%	0.00%
CSX Corp	CSX	1878.55	27.84	52,298.72	0.14%	1.87%	0.00%	7.13%	0.01%
Edwards Lifesciences Corp	EW	587.86	76.04	44,701.25	0.12%			7.04%	0.01%
Ameriprise Financial Inc	AMP	95.81	465.94	44,643.56	0.12%	1.37%	0.00%	7.28%	0.01%
Zebra Technologies Corp	ZBRA	51.14	246.24	12,593.53					
Zimmer Biomet Holdings Inc	ZBH	197.84	101.51	20,082.87		0.95%			
Camden Property Trust	CPT	108.80	114	12,403.11	0.03%	3.68%	0.00%	1.25%	0.00%
CBRE Group Inc	CBRE	298.10	120.73	35,990.20					
Mastercard Inc	MA	902.49	533.48	481,458.87	1.33%	0.57%	0.01%	13.27%	0.18%
CarMax Inc	KMX	152.68	65.03	9,929.06	0.03%			16.70%	0.00%
Intercontinental Exchange Inc	ICE	574.50	163.23	93,775.31	0.26%	1.18%	0.00%	14.41%	0.04%
Fidelity National Information Services Inc	FIS	529.69	79.26	41,983.36	0.12%	2.02%	0.00%	9.27%	0.01%
Smurfit WestRock PLC	SW	521.98	42.23	22,043.18		4.08%		63.58%	
Chipotle Mexican Grill Inc	CMG	1347.36	51.78	69,766.51	0.19%			16.26%	0.03%
Wynn Resorts Ltd	WYNN	106.17	82.11	8,717.40	0.02%	1.22%	0.00%	7.51%	0.00%
Live Nation Entertainment Inc	LYV	234.09	132.76	31,077.72	0.09%			9.42%	0.01%
Assurant Inc	AIZ	50.87	190.83	9,707.13		1.68%			
NRG Energy Inc	NRG	203.67	108.33	22,063.24		1.62%			
Monster Beverage Corp	MNST	973.16	58.67	57,095.23	0.16%			14.23%	0.02%
Regions Financial Corp	RF	905.47	20.28	18,362.83	0.05%	4.93%	0.00%	6.18%	0.00%
Baker Hughes Co	BKR	990.75	36.45	36,112.84	0.10%	2.52%	0.00%	8.81%	0.01%
Mosaic Co/The	MOS	317.23	29.13	9,240.90		3.02%			
Expedia Group Inc	EXPE	122.04	160.11	19,540.05	0.05%	1.00%	0.00%	19.43%	0.01%
CF Industries Holdings Inc	CF	166.47	78.47	13,062.68		2.55%		-5.40%	
APA Corp	APA	361.66	16.35	5,913.20	0.02%	6.12%	0.00%	0.35%	0.00%
Leidos Holdings Inc	LDOS	128.21	145.71	18,682.04	0.05%	1.10%	0.00%	7.40%	0.00%
Alphabet Inc	GOOG	5459.00	163.85	894,457.15	2.48%	0.51%	0.01%	12.96%	0.32%
TKO Group Holdings Inc	TKO	81.55	157.1	12,812.11		0.97%			
First Solar Inc	FSLR	107.24	141.86	15,213.13				41.87%	
Discover Financial Services	DFS	251.60	184.86	46,511.54	0.13%	1.51%	0.00%	1.61%	0.00%
Visa Inc	V	1723.36	335.17	577,619.36	1.60%	0.70%	0.01%	12.19%	0.20%
Mid-America Apartment Communities Inc	MAA	116.90	159.38	18,631.66	0.05%	3.80%	0.00%	2.74%	0.00%
Xylem Inc/NY	XYL	243.35	116.1	28,252.87		1.38%			
Marathon Petroleum Corp	MPC	311.53	137.44	42,816.87		2.65%			
Tractor Supply Co	TSCO	531.62	49.92	26,538.24	0.07%	1.84%	0.00%	8.70%	0.01%
Advanced Micro Devices Inc	AMD	1624.63	96.645	157,012.69				22.74%	

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
ResMed Inc	RMD	146.63	235.88	34,586.47	0.10%	0.90%	0.00%	12.63%	0.01%
Mettler-Toledo International Inc	MTD	20.84	1061.79	22,128.71	0.06%			8.83%	0.01%
VICI Properties Inc	VICI	1056.70	32.22	34,046.96	0.09%	5.37%	0.01%	2.59%	0.00%
Copart Inc	CPRT	966.09	60.9	58,835.06					
Jacobs Solutions Inc	J	122.54	121.57	14,897.63	0.04%	1.05%	0.00%	11.19%	0.00%
Albemarle Corp	ALB	117.65	57.73	6,791.97		2.81%		83.04%	
Fortinet Inc	FTNT	768.97	101.8	78,281.56	0.22%			9.01%	0.02%
Moderna Inc	MRNA	386.62	27.22	10,523.87	0.03%			15.26%	0.00%
Essex Property Trust Inc	ESS	64.33	275.5	17,721.70	0.05%	3.73%	0.00%	3.33%	0.00%
CoStar Group Inc	CSGP	421.76	82.82	34,930.39					
Realty Income Corp	O	891.77	56.89	50,732.75	0.14%	5.66%	0.01%	3.14%	0.00%
Westinghouse Air Brake Technologies Corp	WAB	171.13	184.03	31,492.38	0.09%	0.54%	0.00%	15.51%	0.01%
Palantir Technologies Inc	PLTR	2262.68	112.78	255,185.36				31.39%	
Pool Corp	POOL	37.72	291.59	10,998.25	0.03%	1.65%	0.00%	6.39%	0.00%
Western Digital Corp	WDC	347.82	40.78	14,184.26				189.78%	
PepsiCo Inc	PEP	1371.08	133.38	182,874.59	0.51%	4.06%	0.02%	3.13%	0.02%
TE Connectivity PLC	TEL	298.35	144.37	43,073.25	0.12%	1.97%	0.00%	8.35%	0.01%
Diamondback Energy Inc	FANG	294.08	136.76	40,218.78		2.92%		-1.38%	
Palo Alto Networks Inc	PANW	662.10	178.98	118,502.66	0.33%			13.48%	0.04%
ServiceNow Inc	NOW	207.00	945.26	195,668.82					
Church & Dwight Co Inc	CHD	246.11	99.31	24,441.08		1.19%			
Federal Realty Investment Trust	FRT	85.78	94.38	8,095.92	0.02%	4.66%	0.00%	4.52%	0.00%
MGM Resorts International	MGM	282.95	31.67	8,961.05	0.02%			7.37%	0.00%
American Electric Power Co Inc	AEP	533.99	106.74	56,997.85	0.16%	3.49%	0.01%	5.20%	0.01%
Invitation Homes Inc	INVH	612.88	33.78	20,703.19	0.06%	3.43%	0.00%	3.76%	0.00%
PTC Inc	PTC	120.32	154.03	18,533.43	0.05%			16.34%	0.01%
JB Hunt Transport Services Inc	JBHT	99.19	129.73	12,868.51	0.04%	1.36%	0.00%	14.67%	0.01%
Lam Research Corp	LRCX	1283.66	71.42	91,679.14	0.25%	1.29%	0.00%	17.27%	0.04%
Mohawk Industries Inc	MHK	62.52	106.87	6,681.04	0.02%			4.53%	0.00%
GE HealthCare Technologies Inc	GEHC	457.84	68.42	31,325.63	0.09%	0.20%	0.00%	9.53%	0.01%
Pentair PLC	PNR	164.53	90	14,807.43	0.04%	1.11%	0.00%	9.53%	0.00%
Vertex Pharmaceuticals Inc	VRTX	257.08	493.84	126,956.80					
Amcor PLC	AMCR	1445.34	9.54	13,788.57	0.04%	5.35%	0.00%	4.99%	0.00%
Meta Platforms Inc	META	2181.27	547.27	1,193,743.85	3.31%	0.38%	0.01%	12.01%	0.40%
T-Mobile US Inc	TMUS	1135.45	232.77	264,297.56		1.51%			
United Rentals Inc	URI	65.00	633.6	41,183.39	0.11%	1.13%	0.00%	6.76%	0.01%
Alexandria Real Estate Equities Inc	ARE	172.99	75.88	13,126.41	0.04%	6.96%	0.00%	2.61%	0.00%
Honeywell International Inc	HON	643.26	199.16	128,111.06	0.36%	2.27%	0.01%	6.99%	0.02%
Delta Air Lines Inc	DAL	652.96	41.58	27,149.88	0.08%	1.44%	0.00%	1.02%	0.00%
United Airlines Holdings Inc	UAL	327.70	68.2	22,349.40	0.06%			4.96%	0.00%
Seagate Technology Holdings PLC	STX	211.71	82.7	17,508.20		3.48%			
News Corp	NWS	189.34	31.23	5,913.11		0.64%			
Centene Corp	CNC	497.60	57.69	28,706.72	0.08%			7.97%	0.01%
Apollo Global Management Inc	APO	570.48	133.4	76,102.09	0.21%	1.39%	0.00%	14.13%	0.03%
Martin Marietta Materials Inc	MLM	60.60	504.44	30,569.21	0.08%	0.63%	0.00%	11.00%	0.01%
Teradyne Inc	TER	161.54	77.12	12,457.88	0.03%	0.62%	0.00%	6.69%	0.00%
PayPal Holdings Inc	PYPL	977.40	65.34	63,863.00	0.18%			12.44%	0.02%
Tesla Inc	TSLA	3220.96	284.95	917,811.47					
Blackrock Inc	BLK	155.02	907.69	140,711.97	0.39%	2.30%	0.01%	2.09%	0.01%
KKR & Co Inc	KKR	888.25	113.63	100,931.91		0.62%			
Arch Capital Group Ltd	ACGL	375.72	90.68	34,069.93	0.09%			3.20%	0.00%
Dow Inc	DOW	705.76	30.02	21,187.05	0.06%	9.33%	0.01%	14.77%	0.01%
Everest Group Ltd	EG	47.78	353.15	16,875.23		2.27%		27.82%	
Teledyne Technologies Inc	TDY	46.84	458.6	21,479.59	0.06%			9.78%	0.01%
Domino's Pizza Inc	DPZ	34.30	487.58	16,722.55	0.05%	1.43%	0.00%	9.04%	0.00%
GE Vernova Inc	GEV	272.93	372.42	101,646.36		0.27%		97.71%	
News Corp	NWSA	378.06	27.13	10,256.63		0.74%			
Exelon Corp	EXC	1009.54	46.22	46,660.74	0.13%	3.46%	0.00%	7.29%	0.01%
Global Payments Inc	GPN	245.88	72.48	17,821.11	0.05%	1.38%	0.00%	9.66%	0.00%
Crown Castle Inc	CCI	435.43	100.19	43,626.11		6.25%		33.10%	
Align Technology Inc	ALGN	73.21	183.35	13,423.11	0.04%			9.61%	0.00%
Kenvue Inc	KVUE	1918.69	23.01	44,149.08		3.56%		33.82%	
Targa Resources Corp	TRGP	217.59	177.62	38,647.51		2.25%			
Bunge Global SA	BG	133.97	80.91	10,839.35	0.03%	3.36%	0.00%	3.29%	0.00%
LKQ Corp	LKQ	258.15	37.41	9,657.30		3.21%			
Deckers Outdoor Corp	DECK	151.77	109.19	16,572.16				22.63%	
Workday Inc	WDAY	216.64	239.53	51,890.66					
Zoetis Inc	ZTS	446.18	153.47	68,475.24	0.19%	1.30%	0.00%	8.20%	0.02%
Equinix Inc	EQIX	97.82	838.1	81,981.48		2.24%			
Digital Realty Trust Inc	DLR	336.75	159.88	53,839.39	0.15%	3.05%	0.00%	6.61%	0.01%
Molina Healthcare Inc	MOH	54.20	314.51	17,046.44	0.05%			11.34%	0.01%
Las Vegas Sands Corp	LVS	706.63	35.89	25,360.86	0.07%	2.79%	0.00%	5.45%	0.00%

Notes:

[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Bloomberg Professional as of April 25, 2025
[5] Bloomberg Professional as of April 25, 2025
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of April 25, 2025
[9] Equals [7] x [8]
[10] Bloomberg Professional, as of April 25, 2025
[11] Equals [7] x [10]



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9232422
R Square	0.8523762
Adjusted R Square	0.8515374
Standard Error	0.0054701
Observations	178

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.03041	0.03041	1,016.21981	0.00000
Residual	176	0.00527	0.00003		
Total	177	0.03567			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0787	0.00	86.81	0.0000	0.0769	0.0805	0.0769	0.0805
U.S. Govt. 30-year Treasury	(0.4277)	0.01	(31.88)	0.0000	(0.4542)	(0.4012)	(0.4542)	(0.4012)

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.68%	5.87%	10.55%
Blue Chip Near-Term Projected Forecast (Q3 2025 - Q3 2026) [5]	4.44%	5.97%	10.41%
Blue Chip Long-Term Projected Forecast (2026-2030) [6]	4.30%	6.03%	10.33%
AVERAGE			10.43%

Notes:
[1] Source: Regulatory Research Associates, rate cases through April 25, 2025
[2] Source: S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: S&P Capital IQ Pro, 30-day average as of April 25, 2025
[5] Source: Blue Chip Financial Forecasts, Vol. 44, No. 5, May 1, 2025, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.078703 + (-0.427712 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized Natual Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
1980.1	13.45%	11.66%	1.79%
1980.2	14.38%	10.52%	3.85%
1980.3	13.87%	10.85%	3.02%
1980.4	14.35%	12.10%	2.25%
1981.1	14.71%	12.53%	2.18%
1981.2	14.61%	13.24%	1.36%
1981.3	14.86%	14.13%	0.72%
1981.4	15.70%	13.85%	1.86%
1982.1	15.55%	13.96%	1.59%
1982.2	15.62%	13.52%	2.10%
1982.3	15.77%	12.79%	2.97%
1982.4	15.63%	10.75%	4.89%
1983.1	15.41%	10.71%	4.71%
1983.2	14.84%	10.65%	4.19%
1983.3	15.24%	11.62%	3.62%
1983.4	15.40%	11.74%	3.66%
1984.1	15.39%	12.04%	3.35%
1984.2	15.07%	13.18%	1.89%
1984.3	15.46%	12.69%	2.77%
1984.4	15.33%	11.70%	3.63%
1985.1	15.03%	11.58%	3.45%
1985.2	15.44%	11.00%	4.45%
1985.3	14.64%	10.55%	4.08%
1985.4	14.37%	10.04%	4.33%
1986.1	14.05%	8.77%	5.28%
1986.2	13.28%	7.49%	5.79%
1986.3	13.09%	7.40%	5.69%
1986.4	13.62%	7.53%	6.09%
1987.1	12.61%	7.49%	5.11%
1987.2	13.04%	8.53%	4.51%
1987.3	12.70%	9.06%	3.64%
1987.4	12.69%	9.23%	3.46%
1988.1	12.94%	8.63%	4.31%
1988.2	12.48%	9.06%	3.41%
1988.3	12.79%	9.18%	3.61%
1988.4	12.98%	8.97%	4.00%
1989.1	12.99%	9.04%	3.96%
1989.2	13.25%	8.70%	4.55%
1989.3	12.56%	8.12%	4.44%
1989.4	12.94%	7.93%	5.00%
1990.1	12.68%	8.44%	4.24%
1990.2	12.81%	8.65%	4.16%
1990.3	12.36%	8.79%	3.57%
1990.4	12.78%	8.56%	4.22%
1991.1	12.69%	8.20%	4.49%
1991.2	12.53%	8.31%	4.22%
1991.3	12.43%	8.19%	4.24%
1991.4	12.33%	7.85%	4.48%
1992.1	12.42%	7.81%	4.61%
1992.2	11.98%	7.90%	4.09%
1992.3	11.87%	7.45%	4.42%
1992.4	11.94%	7.52%	4.42%
1993.1	11.75%	7.07%	4.68%
1993.2	11.71%	6.86%	4.85%
1993.3	11.39%	6.32%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.58%	4.54%
1994.2	10.84%	7.36%	3.47%
1994.3	10.87%	7.59%	3.28%

	[1]	[2]	[3]
Quarter	Average Authorized Natual Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
1994.4	11.53%	7.96%	3.56%
1995.2	11.00%	6.94%	4.06%
1995.3	11.07%	6.72%	4.35%
1995.4	11.61%	6.24%	5.37%
1996.1	11.45%	6.29%	5.16%
1996.2	10.88%	6.92%	3.95%
1996.3	11.25%	6.97%	4.28%
1996.4	11.19%	6.62%	4.57%
1997.1	11.31%	6.82%	4.49%
1997.2	11.70%	6.94%	4.76%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.15%	4.77%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.48%	5.93%
1998.4	11.69%	5.11%	6.58%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.80%	5.45%
1999.4	10.38%	6.26%	4.12%
2000.1	10.66%	6.30%	4.36%
2000.2	11.03%	5.98%	5.05%
2000.3	11.33%	5.79%	5.54%
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.45%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.52%	5.15%
2002.2	11.64%	5.62%	6.03%
2002.3	11.50%	5.09%	6.41%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.85%	6.53%
2003.2	11.36%	4.60%	6.76%
2003.3	10.61%	5.11%	5.50%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.88%	6.18%
2004.2	10.57%	5.34%	5.24%
2004.3	10.37%	5.11%	5.26%
2004.4	10.66%	4.93%	5.73%
2005.1	10.65%	4.71%	5.94%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.42%	6.05%
2005.4	10.32%	4.65%	5.66%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	5.00%	5.34%
2006.4	10.14%	4.74%	5.40%
2007.1	10.52%	4.80%	5.72%
2007.2	10.13%	4.99%	5.14%
2007.3	10.03%	4.95%	5.08%
2007.4	10.12%	4.61%	5.50%
2008.1	10.38%	4.41%	5.97%
2008.2	10.17%	4.57%	5.59%
2008.3	10.55%	4.45%	6.10%
2008.4	10.34%	3.64%	6.69%
2009.1	10.24%	3.44%	6.80%
2009.2	10.11%	4.17%	5.94%
2009.3	9.88%	4.32%	5.56%
2009.4	10.31%	4.34%	5.97%
2010.1	10.24%	4.62%	5.61%
2010.2	9.99%	4.37%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.92%

	[1]	[2]	[3]
Quarter	Average Authorized Natual Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.70%	5.95%
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%
2012.2	9.83%	2.94%	6.89%
2012.3	9.75%	2.74%	7.01%
2012.4	10.06%	2.86%	7.19%
2013.1	9.57%	3.13%	6.44%
2013.2	9.47%	3.14%	6.33%
2013.3	9.60%	3.71%	5.89%
2013.4	9.83%	3.79%	6.04%
2014.1	9.54%	3.69%	5.85%
2014.2	9.84%	3.44%	6.39%
2014.3	9.45%	3.27%	6.18%
2014.4	10.28%	2.96%	7.32%
2015.1	9.47%	2.55%	6.91%
2015.2	9.43%	2.88%	6.55%
2015.3	9.75%	2.96%	6.79%
2015.4	9.68%	2.96%	6.71%
2016.1	9.48%	2.72%	6.76%
2016.2	9.42%	2.57%	6.85%
2016.3	9.47%	2.28%	7.19%
2016.4	9.67%	2.83%	6.84%
2017.1	9.60%	3.05%	6.55%
2017.2	9.47%	2.90%	6.57%
2017.3	10.14%	2.82%	7.32%
2017.4	9.70%	2.82%	6.88%
2018.1	9.68%	3.02%	6.66%
2018.2	9.43%	3.09%	6.34%
2018.3	9.71%	3.06%	6.65%
2018.4	9.53%	3.27%	6.26%
2019.1	9.55%	3.01%	6.54%
2019.2	9.73%	2.78%	6.94%
2019.3	9.95%	2.29%	7.67%
2019.4	9.74%	2.26%	7.48%
2020.1	9.35%	1.89%	7.46%
2020.2	9.55%	1.38%	8.17%
2020.3	9.52%	1.37%	8.15%
2020.4	9.50%	1.62%	7.87%
2021.1	9.71%	2.07%	7.63%
2021.2	9.48%	2.26%	7.22%
2021.3	9.43%	1.93%	7.50%
2021.4	9.59%	1.95%	7.65%
2022.1	9.38%	2.25%	7.12%
2022.2	9.23%	3.05%	6.18%
2022.3	9.52%	3.26%	6.26%
2022.4	9.65%	3.89%	5.75%
2023.1	9.64%	3.75%	5.89%
2023.2	9.40%	3.81%	5.59%
2023.3	9.53%	4.23%	5.30%
2023.4	9.62%	4.58%	5.04%
2024.1	9.62%	4.32%	5.29%
2024.2	9.97%	4.58%	5.40%
2024.3	9.58%	4.23%	5.35%
2024.4	9.70%	4.50%	5.21%
2025.1	9.73%	4.72%	5.02%
2025.2	9.90%	4.72%	5.18%
AVERAGE	11.32%	6.03%	5.29%
MEDIAN	10.67%	5.11%	5.45%

BUSINESS SEGMENT DATA FOR CHESAPEAKE UTILITIES CORPORATION, NEW JERSEY RESOURCES CORPORATION AND SOUTHWEST GAS HOLDINGS

Chesapeake Utilities Corporation - Operating Income ($000)

Year	Total	Natural Gas Distribution	Electric Distribution	Natural Gas Transmission	Unregulated Energy	Other Businesses and Eliminations	Notes	Percent Elec. & Gas Dist. / Total	Percent Gas Dist. / Total
2024	228,200	104,212	10,221	81,767	31,700	300	[1]	50.15%	45.67%
2023	150,800	54,213	6,771	65,216	24,400	200	[1]	40.44%	35.95%
2022	142,900	52,803	6,501	55,996	27,500	100	[1]	41.50%	36.95%
3 yr. average								**44.03%**	**39.52%**

DTE Energy Company - Operating Income ($000)

Year	Total	Electric	Gas	DTE Vantage	Energy Trading	Reclassifications and Eliminations	Notes	Percent Elec. / Total	Percent Gas Dist. / Total
2024	2,091,000	1,437,000	434,000	34,000	189,000	(3,000)	[2]	68.72%	20.76%
2023	2,243,000	1,214,000	474,000	104,000	457,000	(6,000)	[2]	54.12%	21.13%
2022	1,748,000	1,305,000	447,000	95,000	(101,000)	2,000	[2]	74.66%	25.57%
3 yr. average								**65.83%**	**22.49%**

New Jersey Resource Corporation - Operating Income ($000)

Year	Total	Natural Gas Distribution	Clean Energy Ventures	Energy Services	Storage and Transportation	Home Services and Other & Eliminations	Notes	Percent Reg / Total	Percent Gas Dist. / Total
2024	458,104	207,118	58,652	154,279	27,198	10,857	[2]	51.15%	45.21%
2023	407,000	207,528	58,722	113,112	32,425	(4,787)	[2]	58.96%	50.99%
2022	406,475	218,973	66,178	95,639	22,163	3,522	[2]	59.32%	53.87%
3 yr. average								**56.48%**	**50.02%**

Operating Income ($000)

	Total Regulated Energy	Delmarva Natural Gas Distribution	Florida Natural Gas Distribution	Florida City Gas	FPU Electric Distribution	Eastern Shore	Peninsula Pipeline	Aspire Energy Express
2024	196,200	12,100	26,400	13,500	5,100	25,200	14,700	900
2023	126,200	9,256	23,840	(3,256)	3,727	23,284	12,195	417
2022	115,300	12,930	19,162	-	3,951	23,222	10,372	439

Net Income ($000)

Notes:
[1] Source: CPK - 2024 For 10-K, pgs. 4 and 78; CPK - 2023 For 10-K, pg. 4; and CPK - 2022 For 10-K, pg. 4
[2] Source: DTE - 2024 Form 10-K, pp. 32, 35, 37, 39, and 56
[3] Source: NJR - 2024 Form 10-K, pp. 42, 46, 47, 50, and 65

Mr. Megginson Constant Growth DCF
As Filed

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
			Closing Monthly Stock Price						Value			
Company	Ticker	Annualized Dividend	Jan 1, 2025	Feb 1, 2025	Mar. 1, 2025	Average	Dividend Yield	Expected Dividend Yield	Line	Zacks	Average	Cost of Equity
Atmos Energy Corporation	ATO	$3.48	$142.51	$152.13	$148.66	$147.77	2.36%	2.43%	6.00%	7.10%	6.55%	8.98%
DTE Energy Company	DTE	$4.36	$119.88	$133.70	$132.03	$128.54	3.39%	3.47%	4.50%	n/a	4.50%	7.97%
New Jersey Resources Corporation	NJR	$1.80	$47.95	$48.38	$48.48	$48.27	3.73%	3.83%	5.00%	6.00%	5.50%	9.33%
NiSource Inc.	NI	$1.12	$37.30	$40.81	$38.82	$38.98	2.87%	2.98%	9.50%	6.00%	7.75%	10.73%
Northwest Natural Gas Company	NWN	$1.96	$39.92	$40.88	$41.48	$40.76	4.81%	4.93%	6.50%	3.70%	5.10%	10.03%
ONE Gas, Inc.	OGS	$2.68	$70.64	$75.15	$73.53	$73.11	3.67%	3.74%	4.00%	3.98%	3.99%	7.73%
Southwest Gas Corporation	SWX	$2.48	$74.68	$75.05	$71.87	$73.87	3.36%	3.48%	10.00%	5.00%	7.50%	10.98%
Spire, Inc.	SR	$3.16	$70.96	$76.86	$75.36	$74.39	4.25%	4.36%	4.50%	5.62%	5.06%	9.42%
Average:												**9.40%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[3] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[4] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[5] Equals averages of [2], [3], [4]
[6] Equals [1] / [5]
[7] Equals [6] x (1 + 0.5 x [10])
[8] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[9] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[10] Equals average of [8], [9]
[11] Equals [7] + [10]

Mr. Megginson Constant Growth DCF
As Adjusted to Exclude NJR & DTE And Correct Zacks Growth Rates

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
			Closing Monthly Stock Price						Value			
Company	Ticker	Annualized Dividend	Jan 1, 2025	Feb 1, 2025	Mar. 1, 2025	Average	Dividend Yield	Expected Dividend Yield	Line	Zacks	Average	Cost of Equity
Atmos Energy Corporation	ATO	$3.48	$142.51	$152.13	$148.66	$147.77	2.36%	2.43%	6.00%	7.10%	6.55%	8.98%
NiSource Inc.	NI	$1.12	$37.30	$40.81	$38.82	$38.98	2.87%	3.00%	9.50%	8.20%	8.85%	11.85%
Northwest Natural Gas Company	NWN	$1.96	$39.92	$40.88	$41.48	$40.76	4.81%	4.96%	6.50%	n/a	6.50%	11.46%
ONE Gas, Inc.	OGS	$2.68	$70.64	$75.15	$73.53	$73.11	3.67%	3.75%	4.00%	4.70%	4.35%	8.10%
Southwest Gas Corporation	SWX	$2.48	$74.68	$75.05	$71.87	$73.87	3.36%	3.50%	10.00%	6.60%	8.30%	11.80%
Spire, Inc.	SR	$3.16	$70.96	$76.86	$75.36	$74.39	4.25%	4.36%	4.50%	6.50%	5.50%	9.86%
Average												**10.34%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[3] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[4] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[5] Equals averages of [2], [3], [4]
[6] Equals [1] / [5]
[7] Equals [6] x (1 + 0.5 x [10])
[8] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[9] Source: Zacks as of March 31, 2025
[10] Equals average of [8], [9]
[11] Equals [7] + [10]

Mr. Megginson Constant Growth DCF
As Adjusted to Exclude NJR & DTE and Update Through April 30, 2025

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
			Average Monthly Stock Price									
Company	Ticker	Annualized Dividend	Feb 1, 2025	Mar. 1, 2025	Apr. 1, 2025	Average	Dividend Yield	Expected Dividend Yield	Value Line	Zacks	Average	Cost of Equity
Atmos Energy Corporation	ATO	$3.48	$152.13	$148.66	$154.91	$151.90	2.29%	2.37%	6.00%	7.20%	6.60%	8.97%
NiSource Inc.	NI	$1.12	$40.81	$38.82	$38.95	$39.53	2.83%	2.96%	9.50%	7.90%	8.70%	11.66%
Northwest Natural Gas Company	NWN	$1.96	$40.88	$41.48	$42.52	$41.63	4.71%	4.86%	6.50%	n/a	6.50%	11.36%
ONE Gas, Inc.	OGS	$2.68	$75.15	$73.53	$76.24	$74.97	3.57%	3.66%	4.00%	5.60%	4.80%	8.46%
Southwest Gas Corporation	SWX	$2.48	$75.05	$71.87	$71.63	$72.85	3.40%	3.57%	10.00%	9.50%	9.75%	13.32%
Spire, Inc.	SR	$3.14	$76.86	$75.36	$76.70	$76.31	4.12%	4.23%	4.50%	6.50%	5.50%	9.73%
Average												**10.58%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[3] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[4] Source: S&P Capital IQ Pro
[5] Equals averages of [2], [3], [4]
[6] Equals [1] / [5]
[7] Equals [6] x (1 + 0.5 x [10])
[8] Source: Exhibit S-4, Schedule D-5, page 5 of 14
[9] Source: Zacks as of April 25, 2025
[10] Equals average of [8], [9]
[11] Equals [7] + [10]

Mr. Coppola Constant Growth DCF
As Filed

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Projected Annual Dividend			Average 30-Day High/Low	Expected Dividend	Projected EPS Growth Rates					
							Value Line			Zacks		Cost of
Company	Ticker	2025	2026	Average	Stock Price	Yield	2024 EPS	2029 EPS	Growth	Growth	Average	Equity
Atmos Energy	ATO	$3.48	$3.68	$3.58	$147.59	2.43%	$6.83	$8.65	4.84%	7.00%	5.92%	8.34%
Black Hills	BKH	$2.70	$2.80	$2.75	$59.90	4.59%	$3.91	$4.80	4.19%	n/a	4.19%	8.78%
Chesapeake Utilities	CPK	$2.64	$2.80	$2.72	$121.24	2.24%	$5.05	$6.80	6.13%	n/a	6.13%	8.37%
NiSource	NI	$1.12	$1.20	$1.16	$39.16	2.96%	$1.75	$2.55	7.82%	7.00%	7.41%	10.37%
Northwest Natural Holdings	NWN	$1.96	$1.97	$1.97	$40.94	4.80%	$3.00	$3.45	3.56%	n/a	3.56%	8.36%
One Gas	OGS	$2.68	$2.72	$2.70	$72.77	3.71%	$3.85	$5.25	6.40%	5.00%	5.70%	9.41%
Southwest Gas	SWX	$2.48	$2.48	$2.48	$75.43	3.29%	$3.60	$4.85	7.74%	6.00%	6.87%	10.16%
Spire	SR	$3.14	$3.26	$3.20	$74.43	4.30%	$4.19	$5.25	4.61%	5.00%	4.81%	9.11%
Average												**9.11%**

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Equals average of [1], [2]
[4] Source: Exhibit AG-43
[5] Equals [3] / [4]
[6] Source: Value Line (For NWN & SWX - 2025 EPS)
[7] Source: Value Line
[8] Equals (([7] / [6])^(1/5))-1 (For SWX & NWN - Equals (([7] / [6])^(1/4))-1)
[9] Source: Exhibit AG-43
[10] Equals average of [8], [9]
[11] Equals [5] + [10]

Mr. Coppola Constant Growth DCF
As Adjusted Excl. BKH & CPK And Updated Through April 30, 2025

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
		Projected Annual Dividend			Average 30-Day High/Low	Expected Dividend	Projected EPS Growth Rates					
							Value Line			Zacks		Cost of
Company	Ticker	2025	2026	Average	Stock Price	Yield	2024 EPS	2029 EPS	Growth	Growth	Average	Equity
Atmos Energy	ATO	$3.48	$3.68	$3.58	$153.44	2.33%	$6.83	$8.65	4.84%	7.20%	6.02%	8.35%
NiSource	NI	$1.12	$1.20	$1.16	$39.15	2.96%	$1.75	$2.55	7.82%	7.90%	7.86%	10.82%
Northwest Natural Holdings	NWN	$1.96	$1.97	$1.97	$42.22	4.65%	$3.00	$3.45	3.56%	n/a	3.56%	8.21%
One Gas	OGS	$2.68	$2.72	$2.70	$75.48	3.58%	$3.85	$5.25	6.40%	5.60%	6.00%	9.58%
Southwest Gas	SWX	$2.48	$2.48	$2.48	$72.30	3.43%	$3.60	$4.85	7.74%	9.50%	8.62%	12.05%
Spire	SR	$3.14	$3.26	$3.20	$76.83	4.16%	$4.19	$5.25	4.61%	6.50%	5.56%	9.72%
Average												**9.79%**

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Equals average of [1], [2]
[4] Source: S&P Capital IQ Pro.
[5] Equals [3] / [4]
[6] Source: Value Line (For NWN & SWX - 2025 EPS)
[7] Source: Value Line
[8] Equals (([7] / [6])^(1/5))-1 (For SWX & NWN - Equals (([7] / [6])^(1/4))-1)
[9] Source: Zacks as of April 25, 2025
[10] Equals average of [8], [9]
[11] Equals [5] + [10]

Calculation of Long-Term GDP Growth Rate Consistent with *Ibbotson* Methodology

Description	Notes	Year	Amount
Change in Real GDP			
Real GDP ($ Billions)	[1]	1929	$ 1,191.1
Real GDP ($ Billions)	[1]	2024	$ 23,305.0
Compound Annual Growth Rate			**3.18%**
Projected Inflation			
Consumer Price Index (YoY % Change)	[2]	2031-2035	2.20%
Consumer Price Index (All-Urban)	[3]	2035	3.86
Consumer Price Index (All-Urban)	[3]	2050	5.37
Compound Annual Growth Rate			2.23%
GDP Chain-type Price Index (2012=1.000)	[3]	2035	1.66
GDP Chain-type Price Index (2012=1.000)	[3]	2050	2.30
Compound Annual Growth Rate			2.18%
Average Inflation Forecast	[4]		**2.20%**
Long-Term GDP Growth Rate	[5]		**5.45%**

Notes:
[1] Bureau of Economic Analysis, March 27, 2025
[2] Blue Chip Financial Forecasts, Vol. 43, No. 12, November 27, 2024, at 14
[3] Energy Information Administration, Annual Energy Outlook 2025 at Table 20, April 15, 2025
[4] Average of 3 inflation sources
[5] Equals (1+3.18%) x (1+2.20%)-1

Mr. Walters Constant Growth DCF Analysis Using Projected EPS Growth Rates
As Filed

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
			Analysts' Projected EPS Growth Rates						
Company	Ticker	13-wk Avg Stock Price	Zacks	MI	I/B/E/S	Average	Annualized Dividend	Adjusted Yield	Cost of Equity
Atmos Energy Corporation	ATO	$ 144.46	7.10%	7.44%	7.00%	7.18%	$ 3.48	2.58%	9.76%
Northwest Natural Gas Company	NWN	$ 40.45	n/a	6.50%	6.00%	6.25%	$ 1.96	5.15%	11.40%
ONE Gas, Inc.	OGS	$ 71.23	4.66%	2.63%	n/a	3.65%	$ 2.68	3.90%	7.54%
Southwest Gas Holdings, Inc.	SWX	$ 73.43	6.61%	10.55%	n/a	8.58%	$ 2.48	3.67%	12.25%
Spire, Inc.	SR	$ 71.81	6.54%	8.08%	n/a	7.31%	$ 3.14	4.69%	12.00%
American States Water Company	AWR	$ 75.57	1.75%	1.75%	1.70%	1.73%	$ 1.86	2.50%	4.24%
American Water Works Co. Inc.	AWK	$ 129.79	8.30%	7.96%	8.30%	8.19%	$ 3.06	2.55%	10.74%
California Water Service Group	CWT	$ 45.15	42.44%	42.44%	42.40%	42.43%	$ 1.12	3.53%	45.96%
Essential Utilities, Inc.	WTRG	$ 36.41	6.58%	6.51%	n/a	6.55%	$ 1.30	3.80%	10.35%
Middlesex Water Company	MSEX	53.23	13.96%	13.96%	n/a	13.96%	$ 1.36	2.91%	16.87%
SJW Group	SJW	$ 50.77	4.52%	4.52%	4.50%	4.51%	$ 1.60	3.29%	7.81%
Average									**13.54%**
Median									**10.74%**

Notes:
[1] Source: Exhibit AB-9
[2] Source: Exhibit AB-8
[3] Source: Exhibit AB-8
[4] Source: Exhibit AB-8
[5] Equals average of [2], [3], [4]
[6] Source: Exhibit AB-9
[7] Equals ([6] / [1]) X (1 + [5])
[8] Equals [7] + [5]

Mr. Walters Constant Growth DCF Analysis Using Projected EPS Growth Rates Adjusted to Include NiSource

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
			Analysts' Projected EPS Growth Rates						
Company	Ticker	13-wk Avg Stock Price	Zacks	MI	I/B/E/S	Average	Annualized Dividend	Adjusted Yield	Cost of Equity
Atmos Energy Corporation	ATO	$ 144.46	7.10%	7.44%	7.00%	7.18%	$ 3.48	2.58%	9.76%
NiSource Inc.	NI	$ 38.09	8.20%	8.22%	8.15%	8.19%	$ 1.12	3.18%	11.37%
Northwest Natural Gas Company	NWN	$ 40.45	n/a	6.50%	6.00%	6.25%	$ 1.96	5.15%	11.40%
ONE Gas, Inc.	OGS	$ 71.23	4.66%	2.63%	n/a	3.65%	$ 2.68	3.90%	7.54%
Southwest Gas Holdings, Inc.	SWX	$ 73.43	6.61%	10.55%	n/a	8.58%	$ 2.48	3.67%	12.25%
Spire, Inc.	SR	$ 71.81	6.54%	8.08%	n/a	7.31%	$ 3.14	4.69%	12.00%
American States Water Company	AWR	$ 75.57	1.75%	1.75%	1.70%	1.73%	$ 1.86	2.50%	4.24%
American Water Works Co. Inc.	AWK	$ 129.79	8.30%	7.96%	8.30%	8.19%	$ 3.06	2.55%	10.74%
California Water Service Group	CWT	$ 45.15	42.44%	42.44%	42.40%	42.43%	$ 1.12	3.53%	45.96%
Essential Utilities, Inc.	WTRG	$ 36.41	6.58%	6.51%	n/a	6.55%	$ 1.30	3.80%	10.35%
Middlesex Water Company	MSEX	53.23	13.96%	13.96%	n/a	13.96%	$ 1.36	2.91%	16.87%
SJW Group	SJW	$ 50.77	4.52%	4.52%	4.50%	4.51%	$ 1.60	3.29%	7.81%
Average									**13.36%**
Median									**11.05%**

Notes:
[1] Source: Exhibit AB-9 and Bloomberg Professional (NI)
[2] Source: Exhibit AB-8 and Zacks as of March 31, 2025 (NI)
[3] Source: Exhibit AB-8 and S&P Capital IQ Pro as of March 31, 2025 (NI)
[4] Source: Exhibit AB-8 and Eikon as of March 31, 2025 (NI)
[5] Equals average of [2], [3], [4]
[6] Source: Exhibit AB-9 and Bloomberg Professional (NI)
[7] Equals ([6] / [1]) X (1 + [5])
[8] Equals [7] + [5]

Mr. Bandyk DCF Analysis
As Filed

Company	Ticker	[1] Annualized Dividend	[2] 30-day Average High Stock Price	[3] 30-day Average Average Stock Price	[4] Average Stock Price	[5] Expected Dividend Yield	[6] Exp. Div. Yield Adj. for Flotation Cost	[7] Value Line Projected EPS Growth	[8] Yahoo! Finance Projected EPS Growth	[9] Zacks Projected EPS Growth	[10] Average Projected EPS Gwth Rate	[11] Weight on EPS	[12] Long-Term Gwth Rate	[13] Weight LT Gwth	[14] Cost of Equity
Atmos Energy	ATO	$3.22	$154.04	$145.16	$149.60	2.23%	2.31%	7.00%	7.40%	7.00%	7.13%	80.00%	3.80%	20.00%	8.78%
NiSource	NI	$1.06	$41.30	$38.07	$39.69	2.78%	2.88%	9.50%	7.70%	7.00%	8.07%	80.00%	3.80%	20.00%	10.10%
Northwest Natural Holdings	NWN	$1.95	$42.61	$40.32	$41.47	4.81%	4.99%	6.50%	2.80%	n/a	4.65%	80.00%	3.80%	20.00%	9.47%
One Gas	OGS	$2.64	$76.48	$71.96	$74.22	3.64%	3.77%	3.50%	5.00%	5.00%	4.50%	80.00%	3.80%	20.00%	8.13%
Southwest Gas Corporation	SWX	$2.48	$77.95	$71.39	$74.67	3.43%	3.56%	10.00%	4.00%	6.00%	6.67%	80.00%	3.80%	20.00%	9.65%
Spire	SR	$3.02	$78.33	$73.94	$76.14	4.07%	4.22%	4.50%	6.36%	5.00%	5.29%	80.00%	3.80%	20.00%	9.21%
Average															**9.22%**

Mr. Bandyk DCF Analysis
As Adjusted - Constant Growth DCF & Updated as of April 30, 2025

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	**Ticker**	**Annualized Dividend**	**30-day Average High Stock Price**	**30-day Average Average Stock Price**	**Average Stock Price**	**Expected Dividend Yield**	**Exp. Div. Yield Adj. for Flotation Cost**	**Value Line Projected EPS Growth**	**S&P Capital IQ Projected EPS Growth**	**Zacks Projected EPS Growth**	**Average Projected EPS Gwth Rate**	**Cost of Equity**
Atmos Energy	ATO	$3.48	$155.17	$151.71	$153.44	2.35%	2.43%	6.00%	7.47%	7.20%	6.89%	9.32%
NiSource	NI	$1.12	$39.65	$38.66	$39.15	2.98%	3.09%	9.50%	7.96%	7.90%	8.45%	11.55%
Northwest Natural Holdings	NWN	$1.96	$42.70	$41.74	$42.22	4.81%	4.99%	6.50%	8.25%	n/a	7.38%	12.37%
One Gas	OGS	$2.68	$76.38	$74.58	$75.48	3.64%	3.77%	4.00%	5.17%	5.60%	4.92%	8.70%
Southwest Gas Corporation	SWX	$2.48	$73.27	$71.34	$72.30	3.60%	3.73%	10.00%	n/a	9.50%	9.75%	13.48%
Spire	SR	$3.14	$77.76	$75.90	$76.83	4.21%	4.37%	4.50%	7.54%	6.50%	6.18%	10.55%
Average												**10.99%**

Mr. Megginson CAPM Analysis with Historical Market Risk Premium

As Filed

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Historical Market Return (1928-2023)**	**Historical Long-Term Government Bond Return (1928-2023)**	**Market Risk Premium**	**Cost of Equity**
Atmos Energy Corp	ATO	4.25%	0.90	11.79%	4.85%	6.94%	10.50%
DTE Energy	DTE	4.25%	1.00	11.79%	4.85%	6.94%	11.19%
New Jersey Resources	NJR	4.25%	1.00	11.79%	4.85%	6.94%	11.19%
NiSource, Inc.	NI	4.25%	0.85	11.79%	4.85%	6.94%	10.15%
Northwest Natural Gas Co	NWN	4.25%	0.90	11.79%	4.85%	6.94%	10.50%
ONE Gas, Inc.	OGS	4.25%	0.85	11.79%	4.85%	6.94%	10.15%
Southwest Gas Corp	SWX	4.25%	0.95	11.79%	4.85%	6.94%	10.84%
Spire Inc.	SR	4.25%	0.90	11.79%	4.85%	6.94%	10.50%
						Average:	**10.63%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[3] Source: Exhibit S-4, Schedule D-5, page 6 of 14
[4] Source: Exhibit S-4, Schedule D-5, page 6 of 14
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Megginson CAPM Analysis
with Historical Market Risk Premium

As Adjusted to Account for Inverse Relationship in Interest Rates and the Market Risk Premium

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Historical Market Return (1926-2023)**	**Risk-Free Rate**	**Market Risk Premium**	**Cost of Equity**
Atmos Energy Corp	ATO	4.25%	0.90	12.17%	4.25%	7.92%	11.38%
DTE Energy	DTE	4.25%	1.00	12.17%	4.25%	7.92%	12.17%
New Jersey Resources	NJR	4.25%	1.00	12.17%	4.25%	7.92%	12.17%
NiSource, Inc.	NI	4.25%	0.85	12.17%	4.25%	7.92%	10.98%
Northwest Natural Gas Co	NWN	4.25%	0.90	12.17%	4.25%	7.92%	11.38%
ONE Gas, Inc.	OGS	4.25%	0.85	12.17%	4.25%	7.92%	10.98%
Southwest Gas Corp	SWX	4.25%	0.95	12.17%	4.25%	7.92%	11.77%
Spire Inc.	SR	4.25%	0.90	12.17%	4.25%	7.92%	11.38%
						Average:	**11.53%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[3] Source: 2023 Kroll SBBI Yearbook for 1926-2022 and S&P Capital IQ Pro for 2023
[4] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Megginson CAPM Analysis with Projected Market Risk Premium

As Adjusted to Utilize Mr. Megginson's Approach in Case No. U-21540

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Company's Projected Mkt Return in Direct Testimony**	**Risk-Free Rate**	**Market Risk Premium**	**Cost of Equity**
Atmos Energy Corp	ATO	4.25%	0.90	12.04%	4.25%	7.79%	11.26%
DTE Energy	DTE	4.25%	1.00	12.04%	4.25%	7.79%	12.04%
New Jersey Resources	NJR	4.25%	1.00	12.04%	4.25%	7.79%	12.04%
NiSource, Inc.	NI	4.25%	0.85	12.04%	4.25%	7.79%	10.87%
Northwest Natural Gas Co	NWN	4.25%	0.90	12.04%	4.25%	7.79%	11.26%
ONE Gas, Inc.	OGS	4.25%	0.85	12.04%	4.25%	7.79%	10.87%
Southwest Gas Corp	SWX	4.25%	0.95	12.04%	4.25%	7.79%	11.65%
Spire Inc.	SR	4.25%	0.90	12.04%	4.25%	7.79%	11.26%
						Average:	**11.41%**

Notes:
[1] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[2] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[3] Source: Exhibit A-14 (AEB-1), Schedule D-5, pages 16-21
[4] Source: Exhibit S-4, Schedule D-5, page 7 of 14
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Coppola CAPM Analysis

As Filed

		[1]	[2]	[3]	[4]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Market Risk Premium**	**Cost of Equity**
Atmos Energy Corp	ATO	4.00%	0.90	7.30%	10.57%
Black Hills	BKH	4.00%	1.00	7.30%	11.30%
Chesapeake Utilities	CPK	4.00%	0.85	7.30%	10.21%
NiSource, Inc.	NI	4.00%	0.95	7.30%	10.94%
Northwest Natural Gas Co	NWN	4.00%	0.90	7.30%	10.57%
ONE Gas, Inc.	OGS	4.00%	0.85	7.30%	10.21%
Southwest Gas Corp	SWX	4.00%	0.95	7.30%	10.94%
Spire Inc.	SR	4.00%	0.90	7.30%	10.57%
				Average:	**10.66%**

Notes:
[1] Source: Exhibit AG-44
[2] Source: Exhibit AG-44
[3] Source: Exhibit AG-44
[4] Equals [1] + [2] x [3]

Mr. Coppola CAPM Analysis

As Adjusted to Account for Inverse Relationship in Interest Rates and the Market Risk Premium and Update Risk-Free Rate

		[1]	[2]	[3]	[4]	[5]	[6]
Company	**Ticker**	**Risk-Free Rate**	***Value Line* Beta**	**Historical Market Return (1926-2023)**	**Risk-Free Rate**	**Market Risk Premium**	**Cost of Equity**
Atmos Energy Corp	ATO	4.50%	0.90	12.17%	4.50%	7.67%	11.40%
Black Hills	BKH	4.50%	1.00	12.17%	4.50%	7.67%	12.17%
Chesapeake Utilities	CPK	4.50%	0.85	12.17%	4.50%	7.67%	11.02%
NiSource, Inc.	NI	4.50%	0.95	12.17%	4.50%	7.67%	11.79%
Northwest Natural Gas Co	NWN	4.50%	0.90	12.17%	4.50%	7.67%	11.40%
ONE Gas, Inc.	OGS	4.50%	0.85	12.17%	4.50%	7.67%	11.02%
Southwest Gas Corp	SWX	4.50%	0.95	12.17%	4.50%	7.67%	11.79%
Spire Inc.	SR	4.50%	0.90	12.17%	4.50%	7.67%	11.40%
						Average:	**11.50%**

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 4, April 1, 2025, at 2.
[2] Source: Exhibit AG-44
[3] Source: 2023 Kroll SBBI Yearbook for 1926-2022 and S&P Capital IQ Pro for 2023
[4] Source: Blue Chip Financial Forecasts, Vol. 44, No. 4, April 1, 2025, at 2.
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]

Mr. Bandyk CAPM Analysis

As Filed

Company	Ticker	[1] Risk-Free Rate	[2] *Value Line* Raw Beta	[3] Market Risk Premium	[4] Cost of Equity	[5] *Bloomberg* Raw Beta	[6] Market Risk Premium	[7] Cost of Equity	[8] Average Cost of Equity
Atmos	ATO	4.41%	0.77	4.86%	8.17%	0.61	4.86%	7.40%	7.78%
NiSource	NI	4.41%	0.92	4.86%	8.90%	0.69	4.86%	7.75%	8.33%
Northwest Natural Gas Holding Co	NWN	4.41%	0.77	4.86%	8.17%	0.54	4.86%	7.05%	7.61%
ONE Gas, Inc.	OGS	4.41%	0.77	4.86%	8.17%	0.65	4.86%	7.56%	7.86%
Southwest Gas Corp	SWX	4.41%	0.85	4.86%	8.53%	0.74	4.86%	7.99%	8.26%
Spire, Inc.	SR	4.41%	0.77	4.86%	8.17%	0.64	4.86%	7.52%	7.84%
								Average:	**7.95%**

Notes:
[1] Source: Exhibit CUB-15
[2] Source: Exhibit CUB-17
[3] Source: Exhibit CUB-16
[4] Equals [1] + [2] x [3]
[5] Source: Exhibit CUB-17
[6] Source: Exhibit CUB-16
[7] Equals [1] + [5] x [6]
[8] Equals average of [4] and [7]

Mr. Bandyk CAPM Analysis

As Adjusted to Use Recent Market Return

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
			Value Line			Market		*Bloomberg*			Market		Average
Company	Ticker	Risk-Free Rate	Raw Beta	Market Return	Risk-Free Rate	Risk Premium	Cost of Equity	Raw Beta	Market Return	Risk-Free Rate	Risk Premium	Cost of Equity	Cost of Equity
Atmos	ATO	4.41%	0.77	12.04%	4.41%	7.63%	10.31%	0.61	12.04%	4.41%	7.63%	9.10%	9.70%
NiSource	NI	4.41%	0.92	12.04%	4.41%	7.63%	11.46%	0.69	12.04%	4.41%	7.63%	9.66%	10.56%
Northwest Natural Gas Holding Co	NWN	4.41%	0.77	12.04%	4.41%	7.63%	10.31%	0.54	12.04%	4.41%	7.63%	8.55%	9.43%
ONE Gas, Inc.	OGS	4.41%	0.77	12.04%	4.41%	7.63%	10.31%	0.65	12.04%	4.41%	7.63%	9.36%	9.83%
Southwest Gas Corp	SWX	4.41%	0.85	12.04%	4.41%	7.63%	10.88%	0.74	12.04%	4.41%	7.63%	10.03%	10.45%
Spire, Inc.	SR	4.41%	0.77	12.04%	4.41%	7.63%	10.31%	0.64	12.04%	4.41%	7.63%	9.30%	9.80%
												Average:	**9.96%**

Notes:
[1] Source: Exhibit CUB-15
[2] Source: Exhibit CUB-17
[3] Source: Exhibit A-14 (AEB-1), Schedule D-5, pages 16-21
[4] Source: Exhibit CUB-15
[5] Equals [3] - [4]
[6] Equals [1] + [2] x [5]
[7] Source: Exhibit CUB-17
[8] Source: Exhibit A-14 (AEB-1), Schedule D-5, pages 16-21
[9] Source: Exhibit CUB-15
[10] Equals [8] - [9]
[11] Equals [1] + [7] x [10]
[12] Equals average of [6] and [11]

Service Date: September 26, 2018

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF the Joint Application for Approval to Change and Establish Natural Gas Delivery Service Rates for Energy West Montana, Inc. and Cut Bank Gas Company	)))))	REGULATORY DIVISION DOCKET NO. D2017.9.80 ORDER NO. 7575c

FINAL ORDER

PROCEDURAL HISTORY

1. On September 29, 2017, Energy West Montana, Inc. ("EWM") and Cut Bank Gas Company ("CBGC") submitted their Joint Application to the Montana Public Service Commission ("PSC" or "Commission") for authority to increase and establish natural gas delivery service rates for each utility's service territory ("Joint Application"). EWM and CBGC request that the Commission: authorize EWM and CBGC to change their existing rates and establish new rates as set forth in their Joint Application and supporting testimony; authorize EWM and CBGC to establish the rate design described in the direct testimony filed in support of their Joint Application; and provide such other processes and relief as the Commission deems necessary for final resolution of the issues raised in their Joint Application and supporting testimony. EWM proposed an increase in total operating revenues of $1,526,960 or an increase of 6.53%. This would result in increases in the typical residential bills of EWM and West Yellowstone residential customers of 7.03% and 2.29% respectively. CBGC proposed an increase in total operating revenues of $183,284 or an increase of 14.23%. This would result in an increase in the CBGC typical residential bill of 5.42%. Test. Schulz 2 (Feb. 22, 2018).

2. EWM and CBGC stated the factors contributing to their application to increase rates are: increased investment in physical plant (a significant portion of which relates to the purchase of the Southern Montana Electric Cooperative ("SME") pipeline), general inflation, a new enterprise resource software planning ("ERP") system, which is a Systems, Applications, and Products Software ("SAP"), and decreased consumption by customers. In addition, the

Company proposes to introduce a Gas Infrastructure Reliability Clause ("GIRC") and an accompanying rate adjustment mechanism to fund the GIRC. Test. Degenstein 15 (Sept. 29, 2017).

3. On October 3, 2017, the Commission issued a *Notice of Application and Intervention Deadline*. On October 27, 2017, the Commission issued a *Notice of Staff Action Granting Intervention* to the Montana Consumer Counsel ("MCC"). On October 24, 2017, the Joint Applicants submitted the Supplemental Testimony of Charles E. Loy, making the Joint Application complete and compliant per Commission rules. *See* Mont. Admin. R. 38.2.315 (2017).

4. On November 20, 2017, the Commission issued Procedural Order 7575 setting deadlines for discovery. The Commission established March 8, 2018, as the final day for the Commission to identify additional issues in this docket.

5. On February 22, 2018, EWM/CBGC filed supplemental testimony incorporating the impact of the December 2017 Federal Tax Cut and Job Act ("TCJA") and an increase to the Additions to Plant Account due to a lease buyout of the SAP software from Verilease. These changes reduced the revenue increases requested by EWM and CGBC to $1,361,817 and $178,328, respectively.

6. The final revenue requirement increases submitted by EWM and CBGC incorporating certain of the adjustments suggested by the MCC were $1,144,172 for EWM and $177,964 for CBGC. These represent increases in Operating Revenues of 4.7% and 11.0%, respectively. Hr'g. Ex. JA-12, updated version of JDH-CBG-2R and Hr'g. Ex. JA-13, updated version of JDH-EWM-2R.

7. MCC submitted intervenor testimony on February 22, 2018, which concluded that EWM's requested annual revenue increase was excessive and recommended that the Commission approve a revenue increase of no more than $316,134. MCC recommended CBGC should be authorized an increase of no more than $109,367. These MCC increases did not incorporate the impact of the TCJA. Test. Schulz 2.

8. At a regularly scheduled work session held on March 6, 2018, the Commission voted to identify EWM's line extension policy as an additional issue, requesting additional testimony. The Commission issued a *Notice of Commission Action* providing direction on this

decision. Accordingly, on March 15, 2018, the Commission issued a revised procedural schedule to allow for testimony and discovery.

9. The Commission held a public hearing in this matter on May 9 and 10, 2018, in Great Falls, Montana.

10. At the hearing the MCC had not yet provided an update to rate base or revenue requirements incorporating the TCJA. MCC later provided its updated recommendations in post-hearing exhibits which include the impact of the TCJA. With these updates, MCC recommends a $133,017 increase for EWM and a $70,534 increase for CBGC. MCC Post Hrg. Provides (June 6, 2018).

DISCUSSION AND FINDINGS OF FACT

Gas Infrastructure Replacement Clause (GIRC)

11. EWM and CBGC are requesting the Commission approve a new cost recovery and infrastructure replacement program referred to as the GIRC. The Pipeline and Hazardous Materials Safety Administration ("PHMSA") required EWM/CBGC to establish a Distribution Integrity Management Plan ("DIMP"). The DIMP requires EWM/CBGC to identify and prioritize infrastructure that constitutes a public safety concern for maintenance and replacement. EWM states that "[t]he GIRC plan is a rate mechanism that would allow EWM/CBGC to accelerate DIMP associated capital investment with limited regulatory lag while avoiding the need for more frequent rates." Test. Degenstein 15. Mr. Degenstein states that "[a]n infrastructure replacement mechanism puts structure around activities that are going to take place regardless of rate treatment, as proven by the track record of EWM and CBGC . . . ." *Id.* at 18. Degenstein testifies that without the accelerated investment from the GIRC program, and based on historical replacement rates and current staffing, it would take approximately 45 years to replace the infrastructure identified in its DIMP. With the GIRC, the replacement could be accomplished in 10-12 years. *Id.* at 16. He argued that the lines would eventually leak. Hr'g Tr. 54:11-15 (May 9, 2018). Mr. Degenstein testified that he would accept a sunset provision in the GIRC that would require rate cases at three to five-year intervals. Hr'g Tr. 91:1-12. He also stated that if EWM replaces infrastructure that doesn't need to be replaced, via the GIRC, the Commission has the authority to deny it. Hr'g Tr. 95:20-23.

12. Under the GIRC, there would be an annual filing each year which would allow EWM/CBGC a return on and recovery of the GIRC capital investment from the previous year

(subject to certain tests within the mechanism). Test. Loy, Ex. CEL-EWM-2 (Sept. 29, 2017). The GIRC investment is cumulative on a going-forward basis and every year the associated revenue requirement increases. Per the testimony of EWM, assuming 2018 is the first year of the GIRC investment to be recovered in 2019, and GIRC investment continues for five years in similar amounts, the GIRC revenue requirement grows from $2.34 per year per customer in 2019 to $20.26 per year per customer in 2023. The proposed rate structure includes the same amounts for each customer rate class that would be recovered via a special tariffed GIRC rider. (Test. Loy, Table 2, p. 12).

13. MCC's witness, Mr. Donkin, argues that the GIRC would involve single-issue ratemaking. Donkin states that with or without the GIRC, EWM and CBGC have an obligation, as public utilities, to provide safe and reliable natural gas distribution service to their customers. This suggests they should pursue a proactive mains and services replacement program with or without the GIRC. Mr. Donkin states, "This obligation does not rest on its agreement with Commission rate setting decisions such as trackers like the GIRC proposal, authorized equity returns or other allowances." Test. Donkin 51 (Feb. 22, 2018).

14. The Commission finds that the GIRC program is in the public interest and is approved with a number of necessary modifications. The Commission appreciates the MCC's arguments regarding single-issue ratemaking and the fact that the program will be completed without a GIRC. The Commission agrees with MCC and expects the companies which have the privilege of monopoly to deploy capital at an accelerated pace when it is necessary to meet safety goals, so long as the Commission establishes a fair return on that investment, as this Order does. *Infra* ¶¶ 112-148. However, the Commission is also aware that in circumstances where anticipated incremental capital investment significantly outpaces the recovery of the utility's historic invested capital, the process of filing rate cases may impose such transaction costs and time lag that it may result in a misalignment of a firm's financial incentive with the goals of public utility regulation. Here, several factors combine to warrant the Commission's approval of the GIRC, which is single-issue ratemaking albeit subject to several key protections which protect consumers from the negative phenomena associated with other trackers. First, the spending in question is closely tied to specifically identified goals and discrete from other lines of capital spending by virtue of PHMSA's particularized requirements on natural gas local distribution companies. Test. Degenstein 15-19. Second, the transaction costs associated with a

rate case for companies the size of the Joint Applicants are significant. In this case, rate case expenses for the Joint Applicants are $350,000, which if amortized over five years, results in an annual increase of the revenue requirement for just the rate case expenses in the amount of $70,000. Rebut. Test. Henthorne 8 (Apr. 9, 2018). Although this rate case has allowed a thorough evaluation of the Joint Applicants, and has led the Commission to disallow substantial requests of the utilities in question, it is clear that the transaction costs are significant. Third, the incremental capital investments in question, while no doubt welcomed by a firm that seeks to invest capital and be paid a return largely assured by government for doing so, is being invested pursuant to legal requirements associated with public safety, which alongside affordability is the Commission's foremost priority.

15. In order to remedy the MCC's concerns, the Commission accepts the Joint Applicants' proposal that the GIRC be limited to incremental capital spending net of depreciation and be subject to an earnings test, although the Commission finds that these are unartfully described in the Joint Applicants' proposed tariff. The Commission orders more precise language for these calculations. In the GIRC tariff the Commission approves, language has been added specifying the rate of return used in the earnings test, specifying how the excess accumulated deferred income tax ("EDIT") amortization credit to the GIRC will be quantified, how the annual current year depreciation will be calculated, and how the current year average GIRC plant will be calculated. Likewise, a welcome attribute of the Joint Applicants' proposed GIRC is that its collections in rates are in arrears, only after the spending is made, and not made on projections. The Commission also approves this feature, but adds a reporting requirement of the utilities' anticipated spending, together with a rate filing, which the Commission believes will allow for greater regulatory oversight in both the ongoing surveillance of the GIRC and at that time when the spending is ultimately proposed for inclusion permanently in rate base through a general rate case. In order to cabin the specific programmatic costs, and to prevent the GIRC from becoming a catch-all mechanism for any spending said to be undertaken for the omnibus cause of public safety, the Commission includes specific, identifiable property elements within the tariffs. *See* Attachment A. These are tied to Mr. Degenstein's representations about the need for this program. To ensure transparency on an accounting level, the company will also be required to clear plant to specifically designated FERC accounts. Finally, while the Joint Applicants propose that this surcharge become active with respect to incremental capital

spending undertaken during the 2018 construction season, the Commission defers the implementation of the program by one year; the first year in which incremental capital spending under the GIRC is subject to be surcharged is 2019. The Commission does this in recognition of the fact that the construction season for 2018 is nearly passed, and because the Commission's requirements for the GIRC includes pre-submittal of a plan for each year's deployments, to ensure that the program is fully transparent and subject to ongoing surveillance. Clearly it would not be possible to effectuate such protection if the program were started in reference to 2018.

16. The Commission approves several additional features to the GIRC. First, because the GIRC is designed to avoid transaction costs of more frequent rate cases, it will include an automatic termination provision if either or both of the Joint Applicants file a rate case prior to several years' operation of the GIRC surcharge. Second, it will facilitate a review of whether the investments, in both their need and in the manner in which they have been deployed, were prudentially deployed and in fact used and useful. It does so by including an automatic termination provision for the surcharge after five years of its operation, before which time the Joint Applicants should again file a rate case if they desire these costs to be permanently included in rates. Finally, the GIRC surcharge will likewise automatically terminate if the either or both of the Joint Applicants file a proposal pursuant to Mont. Code Ann. § 69-3-308 (state and local tax tracker). One of the reasons the Commission is granting these utilities a GIRC is their unique regulatory setting, where they have chosen not to use tax tracking mechanisms. While the Joint Applicants are clearly legally entitled to use such a tax tracker, nothing in law permits to them the unilateral right to obtain the GIRC here approved, and because the Commission recognizes that the nature of its decision here is made relative to the overall regulatory setting facing the Joint Applicants, it conditions the GIRC's continued existence on the premise that all else in the regulatory setting is held even. These sunset provisions are an essential consumer protection without which the GIRC might ceaselessly grow without the normal rigors of oversight; without these provisions, the Commission would not approve the GIRC.

17. The Joint Applicants propose to recover the costs of the GIRC through a monthly surcharge on each customer's bill, which is not differentiated by customer class. The Commission, consistent with its discussion of the allocated cost of service of the utility, rejects the proposal insofar as it would charge each customer, regardless of its size, the same surcharge. *Infra* ¶ 158. Instead, the Commission will differentiate the size of the surcharge based on the

allocation factors established in this proceeding. *Id.* The Commission otherwise approves the rate design. While there may be arguments that such incremental capital investment is best recovered through a rate which is partially billed on the sale of gas volumes, such a design would be complex to administer, necessitating deferred accounts to remedy weather-driven over collections or under collections, and would thus frustrate the intention of making the GIRC straightforward but transparent. The Commission, meanwhile, considers the likely presence of a monthly fixed surcharge in the coming years in its decision to hold the existing charge at its present level. *Infra* ¶¶ 157-160.

18. Part of the tax benefits resulting from the Tax Cut and Jobs Act will constitute an offset of the programmatic costs of GIRC. The Commission applies the ongoing effects of the statutory rate reduction into the general rates it sets in this proceeding. *Infra* ¶ 50. The EDIT, which varies significantly year to year, is a coincidental but happy match against a program of variable spending, such as GIRC. The Commission will apply proceeds under EDIT to the program on a matched-year basis, in order to comply with IRS normalization requirements. Meanwhile, for the deferred tax savings that the Commission requires from the effective date of the Act to the date in which rates established under this order are effective, those 2018 savings will be applied to the 2019 spending under GIRC. Likewise, the EDIT from 2018 will be applied against the 2019 spending under GIRC. All of these tax benefits will be treated as customer-contributed capital, reducing the overall incremental capital investments made before a revenue requirement is calculated with respect to the balance. If, during GIRC, there is a year where the incremental capital spending does not meet the earnings test or the net-of-depreciation provision, the GIRC will be allowed to function as a vehicle to refund these tax benefits, although otherwise the surcharge never would be a negative value.

19. All of the associated capital investments made under GIRC, just like all other capital investments that are made in between rate cases, are subject to a complete review at the time when either or both of the utilities file their next general rate case. This will ensure that the annual GIRC proceeding is not unduly bogged down by such a review, addressing one concern MCC raises about the possibility that GIRC will *increase* transaction costs. MCC Br. 3 (June 22, 2018).

20. The Commission is sufficiently comfortable with the design of GIRC, as discussed above, that it is authorizing the program. However, the Commission also is conscious

that this is the first time in its history that such an incremental-capital surcharge has been authorized. The Commission regards the Joint Applicants' new GIRC as a pilot, and the Commission upon its review of the GIRC performance in the utilities' next rate case will be able to draw conclusions about GIRC's performance and may, if it is reauthorized, make modifications that are necessary or reasonable. For this reason, the Commission cautions that it is unlikely to approve similar mechanisms until it can be reasonably confident of the program's actual performance. While this may seem unfair to the other utilities the Commission regulates, the Commission reasons that the Joint Applicants have pressed this cause while others have settled cases by withdrawing such a proposal. *See* MDU/MCC Stipulation, D2017.9.79 ¶ 11 (Apr. 24, 2018). The Joint Applicants' persistence is therefore rewarded by the GIRC as it is here designed. The Commission hopes the GIRC will surface valuable insights about whether such mechanisms are reasonable to use generally and, if so, how they might be designed.

21. The Commission finds a GIRC tariff is appropriate, subject to the various protections written in the tariff, attached to this Order. *See* Attachment A.

SAP Software

22. In 2015, GNI and its subsidiaries, including EWM and CBGC, installed ERP system referred to as the SAP. Test. Henthorne 13 (Sept. 29, 2017). The initial estimate to complete the development and implementation of the SAP to GNI (now Hearthstone) was $4 million. However, the final cost of the SAP software to GNI/Hearthstone was approximately $18 million. *See* Appendix A, and Hr'g Ex. JA-9. Four separate components were considered in arriving at the $18 million figure. First, GNI obtained $10,091,490 in financing from Verilease. *Id.* In addition to the Verilease-provided financing, GNI contributed $3,155,616 of investor-supplied capital towards the purchase; this contribution is referred to as a Deferred Rent Asset by the Joint Applicants. *Id.* GNI also contributed $1,253,811 in additional investor-supplied capital, which is not included as part of the Deferred Rent Asset. *Id.* Finally, GNI bought out the lease obligation with Verilease for $3,558,629. *Id.* The utilities requested that the Commission approve an accounting order permitting them to reclassify the Deferred Rent Asset as a regulatory asset to be amortized over the remaining life of the SAP software (10 years). Test. Henthorne 14, 36; Test. Degenstein 10; Hr'g Tr. 106:17-22; 187:18-23. EWM initially proposed including $627,640 and CBGC proposed to include $51,575 in their rate base for the Deferred Rent SAP asset. Test. Henthorne 14, 36.

23. The MCC expressed concern that the SAP software's final cost far exceeded the initial estimated cost of $4 million. Test. Schulz 13-18; *see* DR PSC-040(b) (Dec. 7, 2018) and DR PSC-083(a) (Feb. 9, 2018). The MCC argued that the utilities are seeking an unusual application of an accounting order in order to recover expenses that exceeded initial estimates and resulted in operating costs that exceeded those they replaced, after those expenses were incurred, i.e., those portions of the SAP system spent by GNI beyond those received from Verilease. *Id.* at 13 (referencing Test. Henthorne 14, 16). According to the MCC, the SAP system "provides no cost 'advantages' but rather represents a dramatic increase in comparable costs from the last rate case," arguing that ratepayers are being "asked to pay for 'value' that cannot be quantified other than to suggest operating efficiencies that have no corresponding economic efficiencies." *Id.* at 14. Further, the MCC points out there are no shown reductions in payroll costs related to saving employee time because of the improved reporting, and "[i]n fact, it appears there are substantial contract labor costs" involved in running the system. *Id.* at 15.

24. The MCC argues that the Joint Applicants suggest "that the lessons of ring-fencing and the cost advantages that are supposed to follow from being part of a larger corporate organization should not apply" to the SAP and recommends the utilities should earn a return of, but not a return on, the $3.1 million deferred rent asset; in other words, the MCC recommends "a disallowance of deferred rent from the rate base." Test. Schulz 17-18. This treatment results in a reduction to rate base of $627,640 for EWM and $51,575 for CBGC. *See* Test. Schulz, Ex. PRS-6EW and Ex. PRS-6CB.

25. There were three schedules to the lease agreements with Verilease. The first terminated in December 2017, and the other two schedules would have terminated in September and October 2018. Hr'g Tr. 120:17-21. At the end of each lease schedule, the Joint Applicants could choose to buy out, extend, or terminate with a fee and with the sale of assets. *Id.* at 108:7-14 and PSC-045 (Dec. 19, 2017). On December 31, 2017, the first schedule reached its maturity and the Joint Applicants made an agreement to buy out the remaining two schedules, but were still obligated to pay the lease obligation through September and October. *Id.* at 120:17-24. The utilities state they did not include the exact buyout amount in the original filing because the final amount was not known and measurable, but argue they included an estimate of additional construction work in progress ("CWIP") they believed they would incur prior to the end of 2017 for the buyout of the SAP lease. DR PSC-138(d) (Mar. 23, 2018); DR PSC-154

(Apr. 20, 2018) ("This can be seen in [EWM's original filing] column F, "Estimated Additions Sep-Dec" of page 3 of Rule No. 38.5.124. In our supplemental filing on February 26, 2018 we trued-up these estimates to actual CWIP additions through the end of 2017, which included additional costs for the SAP asset.")

26. As noted above, the total amount of the SAP asset was $18 million: $13.6 million for the three lease schedules (which includes the $3.558 million lease buyout); $3.1 million for the deferred rent associated with the three lease schedules; and $1.25 million in additional SAP costs. *Id.* at 125:14-126:19; *see* Hr'g Ex. JA-9. When allocated from the parent GNI to EWM, according to Henthorne, "the effect on rate base for EWM of the SAP system is $3.2 million and then we've reduced it by the amount of the capital lease obligation of $1.5 million, so the effect to EWM in rate base in this case is $1.8 million." Hr'g Tr. 112:25-113:4. The Joint Applicants determined the cost of service for the utilities was $738,633 for EWM and $63,071 for CBGC. *Id.* at 127:16-19; *see* Hr'g Ex. JA-9. Ultimately, EWM and CBGC are requesting to place 38% of their allocated SAP costs into rate base at $1,793,345 and $147,898, respectively. Hr'g Ex. JA-9.

27. The Joint Applicants are treating the outstanding lease balance as a reduction to rate base. At hearing, Joint Applicants' witness Henthorne admitted they did not consider an accounting order before incurring expenses until it was raised by the MCC. Hr'g Tr. 107:10-16 ("To be honest with you, I didn't know that avenue was available. When I read Mr. Schulz's testimony, I thought oh, I didn't realize that was an option.").

28. In addition to their capital investment, EWM and CBGC are requesting to recover $291,273 and $26,196, respectively, of ongoing, annual, operating expenses related to the SAP software. DR PSC-013(c) (Nov. 29, 2017). This compares to the $82,452 in annual IT operating costs EWM included in its 2009 filing. Test. Schulz 14. The MCC proposes adjustments to operating expenses related to the SAP software. Mr. Schulz states that "[t]he ERP system resulted in operating costs that are three and a half times comparable costs included in the last EWM rate case. Ratepayers should not be the default insurers of a costly project that increased expenses." *Id.* at 19. In arriving at an alternative figure, the MCC applied the cumulative GDP Implicit Price Deflator of 12% to the comparable software costs reflected in the 2009 rate case filing. *Id.* This adjustment reduces operating expenses from $291,273 to $92,346, a reduction of

$198,927. *Id.* The MCC recommends reducing allowed IT expenses from $26,196 to $8,305 for CBGC. *Id.* at 19-20.

29. The Commission agrees with the Joint Applicants that the information technology landscape has changed dramatically since 2009. Rebut. Test. Henthorne 7. Perhaps the best evidence of this is that CBGC, in its last rate case, recorded no IT expense at all, because its billing was done entirely by hand. Hr'g Tr. 350:19-20. Likewise, in a more digital world, an enterprise system may not be a zero sum game, instead conferring on customers and the utility new benefits. The Commission acknowledges the Joint Applicants' argument that the new software provides customers and the utility benefits the previous software did not. DR PSC-013 (Nov. 17, 2017). However, the record, with a noteworthy exception related below, is absent of what such an enterprise system reasonably should have cost. The Commission reasons that in an era of cloud computing, increased Operations and Maintenance ("O&M") expenses would tradeoff against decreased capital costs. Here, both O&M expenses and capital spending have increased substantially. It is possible that the attendant costs of a more digitized utility are offset by efficiencies elsewhere, as EWM suggested at the hearing. *See* Hr'g Tr. 51:1-22. If indeed that is true, it is hidden amid the overall operations of these utilities, rather than shown by any kind of direct effect.

30. The Commission has not in recent memory seen cost overruns of so significant a magnitude as they present with respect to GNI's enterprise system. The lack of a clear explanation for what contributed to these overruns is frustrating. The situation is all the more confounding because the Joint Applicants' proposal to include the SAP in rates is an accounting morass which defies easy comprehension, as is evident from the summation of parties' testimony above. There is little in the way of a convincing explanation for the more dubious elements of the financial and accounting arrangement in which the Joint Applicants engaged. Two specific examples of this emerge through the parties' testimony and exhibits. First, the $3.2 million Deferred Rent represents, essentially, a cost overrun heaped atop a previous overrun of estimated costs; it goes almost fully unexplained. Meanwhile, the costs associated with the $3.6 million lease buyouts are both speculative, in the sense that testimonial evidence does not establish them as known and measurable changes, and in any case the costs are not convincingly argued relative to their benefits by the Joint Applicants. The Commission finds that the Joint Applicants in this regard have not met their burden of proof. The Commission is persuaded by MCC that absent a

clear showing of benefits relative to the excess costs that some of the cost overrun should be the Joint Applicants' responsibility. Indeed, even the Joint Applicants appear to believe the ultimate cost of the system was unreasonable. As Mr. Degenstein testified at hearing:

> If I were to look at an enterprise software system across a holding company that has multiple utilities with the abilities it has today, my personal opinion is I think it should have been in the 8 to $10 million range and the cost overruns were probably due to the nature of SAP and the difficulty to implement it. But I don't think 4 million was ever realistic.

Hr'g Tr. 75:25, 76:1-8. The Commission accepts Mr. Degenstein's and Mr. Schulz's representations in this regard. Based on both parties' testimony, the Commission disallows from rate base the two accounting elements that the Joint Applicants have provided the least justification for, and which appear to have been incurred only as the cost overrun continued to grow: the Deferred Rent and the lease buyout amounts. This resolution allows the Commission to see the forest for the trees, arriving at a total GNI asset amount of $11,345,301, still above what Mr. Degenstein thinks "should have been" the total cost, while founding its judgment on a disallowance of two of the most peculiar elements of this strange arrangement. When allocated to the Joint Applicants using the undisputed allocation methodology for GNI's subsidiaries, the Commission finds EWM's portion of this asset allowable in rate base is $702,525 and CBGC's portion of this asset is $57,727.

31. The MCC also questions the O&M expenses for GNI, including the costs for consultants. Test. Schulz 15 ("The costs for those consultants alone are more than double all the comparable expenses from the 2009 test year filing of $82,452.") While the Commission acknowledges this concern, the MCC's remedy is unpersuasive because it benchmarks a proposal for allowed spending on 2009 data. Given the degree to which the IT landscape has rapidly transformed life in the United States, it seems unreasonable to tie the allowed costs with those from the previous decade using a generic measure of inflation. Lacking an obvious alternative benchmark, the Commission accepts the Joint Applicants' proposal in this regard. To the degree the costs appear high, their levels will be mitigated in the next rate proceeding. This stands in distinction to the Commission's decision on capital returns; if the Commission were instead to accept the Joint Applicants' representations, it would in effect *reward* the companies for cost overruns for a substantial period of time. The Commission therefore finds that including

the $291,273 (EWM) and $82,452 (CBGC) annual operating costs for recovery in ongoing O&M associated with IT is appropriate.

Tax Cut and Jobs Act and EDIT

32. On December 22, 2017, the federal Tax Cut and Jobs Act ("TCJA") was signed into law. The TCJA, among other things, reduced the federal corporate income tax rate for EWM/CBGC from 34% to 21%, and required public utilities like EWM/CBGC to review their EDIT to align with the reduction in tax rates. TCJA of 2017, Pub. L. No. 115-97, 131 Stat. 2054 § 13001 (2017). On December 27, 2017, the Commission required that information regarding impacts of the TCJA be filed by EWM and CBGC for their gas operations in Montana, and EWM/CBGC filed an amended revenue requirement, accordingly.

33. The Commission identified four rate issues to be addressed as the result of the TCJA:

a. The reduction in the corporate tax rate from 34% to 21%.

b. The amortization of the EDIT balances.

c. The over collection of income taxes from January 1, 2018, until the new rates are implemented, and whether or not a refund is appropriate.

d. The over collection of the EDIT balance from January 1, 2018, until the new rates are implemented, and whether or not a refund is appropriate.

34. The Commission required the utilities to record on their books as a deferred liability the estimated excess revenues expected to be collected by the utility caused by the reduction in the tax rate for the time period preceding the issuance of the final approved rates, as well as a calculation of the EDIT balance caused by the reduction in the FIT rate. Furthermore, the Commission required the Joint Applicants to include a proposal to extinguish the EDIT balance along with a proposal to file periodic reports updating the Commission on the deferred liability and EDIT balances. Henthorne filed supplemental testimony and, subsequently, Ralph C. Smith submitted testimony on behalf of MCC discussing the effects of the TCJA and addressing the representations made by Mr. Henthorne.

35. A reduction in Joint Applicants' corporate income tax rate reduces their revenue requirement, because income taxes are recognized as a recoverable cost. *See* Mont. Admin. R. 38.5.175. Similarly, a reduction in the tax rate results in an EDIT balance. As EWM/CBGC utilize straight-line depreciation for regulatory accounting and accelerated depreciation for tax

purposes, they pay less in federal income tax during the early years of an asset's life than is collected through rates. This tax savings is accounted for as a deferred income tax, treated as zero-cost capital, and is deducted from rate base. Thus, a lower federal income tax rate creates an excess deferred tax balance, which the TCJA requires to be returned to ratepayers. *See* TCJA of 2017 § 13001. The EDIT balances fall into two categories, "protected" which is subject to IRS normalization rules and must be amortized using the Average Rate Assumption Method (ARAM), and "unprotected" where the amortization period is set by the Commission. The Joint Applicants accepted the MCC proposal to amortize the unprotected balance over 40 years.

36. Henthorne stated that while the Joint Applicants will have lower income tax expense in 2018, based on the normalized revenue requirements developed in this case, both companies are significantly under-earning from their most recent allowed rates of return despite the decrease in taxes as a result of the TCJA, and for that reason, no regulatory liability is warranted. Supp. Test. Henthorne 14-15, *see* Ex. JDH-EWM-2-NTL (page 1) and Ex. JDH-CBG-2-NTL (which illustrate an estimated 3.52% ROR to be earned by EWM and a -1.69% loss to be realized by CBGC, after the normalizing adjustments and rate base adjustments described in the preceding section). Accordingly, the Joint Applicants did not record a deferred liability as the Commission requested. The tables below show the TCJA impact on the revenue requirements for EWM (-$353,841) and CBGC (-$24,722) as calculated by the Joint Applicants. *Id.* at Ex. JDH-EWM-6-NTL; Ex. JDH-CBG-4-NTL.

Table 1

EWM	Initial filing	normalizing adjustments	TCJA impacts	Updated for NCA
rate base	$ 20,254,802.00	$ 354,282.00	$ 38,415.00	$ 20,647,499.00
Requested Increase	$ 1,532,291.00	$ 183,367.00	$ (353,841.00)	$ 1,361,817.00

CBGC	Initial filing	normalizing adjustments	TCJA impacts	Updated for NCA
rate base	$ 1,158,692.00	$ 72,958.00	$ 4,969.00	$ 1,236,619.00
Requested Increase	$ 183,284.00	$ 19,764.00	$ (24,722.00)	$ 178,328.00

37. EWM stated that the net EDIT Balance for EWM is $2,023,842 and $204 for CBGC. Supp. Rebut. Test. Henthorne 4-5 (Apr. 25, 2018). The Joint Applicants proposed to amortize both the protected and unprotected EDIT balances using the ARAM, and to extinguish the EDIT balance by incorporating the credits into its proposed GIRC plan. Test. Henthorne 15-17, Ex. JDH-EWM-14; Resp. Test. Smith, 19-20 (Apr. 6, 2018). The utilities argued this would reduce the GIRC-eligible capital expenditures so ratepayers would get an

immediate benefit of this credit. *Id.* at 16. However, the Joint Applicants stated that if the Commission did not approve the extinguishment of the EDIT balances through a credit to GIRC, they would support including the refund calculated at the conclusion of this docket in the distribution rates or establish a negative surcharge separate from the distribution rates. Supp. Rebut. Test. Henthorne 6-8.

38. The Joint Applicants stated that they will not attempt to pursue a retroactive ratemaking defense regarding the deferred liability from excess income tax revenues collected in 2018. They recognize that the Commission was correct in identifying the FIT rate change issue before any effect from the new tax law could occur. However, the utilities state that the Commission's requirement to calculate the liability based on the effect of a full year of the difference in tax rates for a year that has not yet fully occurred creates an accounting problem. According to the Joint Applicants, in order to record a liability, regulatory or otherwise, it has to be: 1) established that there is indeed a liability and to whom; and 2) the liability has to be measurable. A regulatory liability implies that a refund to customers is necessary and therefore a liability is recorded for the amount to be refunded, and, the utilities argue, because both utilities are under-earning, a liability and subsequent refund is not warranted because any "gain" the companies have received as a result of the decreased FIT rate has been offset by increased costs and other items not included in current rates. If the utilities were over-earning, then a liability refund would be warranted, but that is not the case here. *Id.* at 8-9.

39. Henthorne also recognizes measurement as a problem: this case will result in new rates reflecting the reduction in the FIT rate and no liability will be warranted after those new rates go into effect. Furthermore, he notes the revenues of EWM and CBGC are seasonal, with losses projected for the months of May to September 2018.

> As Mr. Smith acknowledges, "the amount of savings associated with the reduction in the FIT rate will depend on the effective date of the new rates established in this rate case." Recording a liability for the full year would almost certainly overstate the amount of the liability, if any, that may be ultimately recorded, with a corresponding increase to expense that would have to be later reversed.

Supp. Rebut. Test. Henthorne 9-10. In summary, Henthorne states that Joint Applicants are not trying to avoid recording a liability and have complied with the Commission's order. Furthermore, if the Commission ultimately determines that a liability for 2018 is warranted, that liability should be based on the Joint Applicants actual results from January 1, 2018,

through the date that new rates at issue become effective. *Id.* at 10.

40. The MCC's witness Smith agrees with the Joint Applicants that the utilities' income tax expense should be reduced to reflect impact of the lower federal income tax rate that will be in effect for 2018. Resp. Test. Smith 7. However, because of differences between the MCC and the joint applicants regarding rate base, capital structure, allowed returns on equity, cost of debt, and net operating income, the income tax allowance proposed by the MCC will differ from that proposed by the Joint Applicants. *Id.* at 12. Smith suggests that the Joint Applicants' proposal to apply the EDIT amortization to their GIRC plan should be rejected. *Id.* at 9. The MCC, while analyzing the utilities' TCJA supplemental filing, did not itself present a recalculated revenue requirement reflecting the MCC's own TCJA analysis.

41. The MCC disagrees with the Joint Applicants that regulatory liability is unwarranted since the utilities are under-earning from their most recent allowed rates of return even after the impact of the decrease in taxes as a result of the TCJA. Smith also noted the Joint Applicants had not complied with the Commission's requirement that the utilities establish a deferred liability to account for the reduction in the FIT rate to 21%, and accordingly, he suggested that the utilities should be required to book the liability. Resp. Test. Smith 32-33. The Joint Applicants calculated the deferred liability (although they have not booked it) in accordance with the Commission directive with EWM's calculated deferred liability as $263,391 and CBGC's deferred liability as $15,992. DR MCC-115 (Mar. 23, 2018). However, the actual amount of income tax savings realized by the TCJA will depend on the effective date for the new rates in this docket since the net income earned fluctuates on a monthly basis. *Id.* at 35. Depending on the effective date of the new rates, Smith maintains that the associated deferred liability should be amortized over an appropriate period such as a 3-year period. *Id.* at 36.

42. As discussed below, the Commission will require the Joint Applicants to apply the accumulated deferral that the Joint Applicants have calculated starting on January 1, 2018, to the GIRC.

43. According to the MCC, the potential cash flow impact of the TCJA could adversely affect a public utility due to increased costs of common equity for utility stocks. Hr'g Tr. 208:3-14. For utility ratemaking purposes, increased estimates of common equity costs result in greater cash flows provided to the utility. These increased cash flows serve to mitigate

the adverse cash flow affect of the TCJA. The MCC also identified that there are alternative approaches available to utilities to mitigate the cash flow impact of the TCJA such as equity thickening in the ratemaking capital structure. Hr'g Tr. 304:15-25, 305:1-20. The greater proportion of equity included in ratemaking capital structure generally provides utilities with greater cash flows due to the fact that financing in the form of equity is costlier to a utility than debt financing. In the ratemaking paradigm, increased financing costs lead to higher allowed returns for utilities and these higher returns provide the utility with increased cash flows. Smith, witness for the MCC, infers that because the Joint Applicants' capital structures are overly equity thick as is, an adjustment to their capital structures is not appropriate in this proceeding, but defers to MCC's witness Hill on this matter. Hr'g Tr. 305:21-25.

44. According to Hill, a utility's operational risk remains unchanged as a result of the TCJA, but its financial situation could change. Hr'g Tr. 465:19-25, 466:1-3. He agrees that bond rating agencies are concerned about the cash flow effects of the TCJA, but contends that the rating agencies are not as concerned about operating companies as they are about holding companies that are highly levered. *Id.* at 466:23-25. Furthermore, he argues that the TCJA serves to potentially impact a utility's cost of debt, rather than equity, and that it is unclear how the TCJA impacts equity costs. *Id.* at 466:4-23. Accordingly, the Commission notes that Hill argues that the impact of the TCJA does not warrant any adjustment, whether it be to the Joint Applicants' authorized ROEs or their ratemaking capital structures.

45. The Joint Applicants, meanwhile, show no evidence to suggest that they have moved to infuse their balance sheet with additional equity in order to protect from potential negative cash flow effects of the TCJA. The Commission concludes this remains a largely hypothetical concern for the Joint Applicants and that adjustments to capital structure should not presume to anticipate managerial decisions which may or may not be prudent.

46. Regarding the amortization of the EDIT balance, the Joint Applicants assert the cleanest option would be to implement a negative surcharge to customers which would be changed every year to track the substantial variations in the amount of EDIT amortization as shown in the table below based upon exhibits provided by the utilities. Supp. Rebut. Test. Henthorne 7-8, Ex., JDH-EWM-14-SR and JBH-CBG-10-SR.

Table 2

EWM/CBGC Annual Edit Amortization		
	EWM	CBGC
2018	($5,184)	($1,273)
2019	$59,355	$1,184
2020	$95,035	$2,241
2021	$141,021	$3,576
2022	$156,409	$3,605
2023	$168,519	$3,439
2024	$176,057	$3,353
2025	$161,379	$2,715
2026	$122,439	$920
2027	$123,898	$890

47. The Commission finds that it is appropriate to require the Joint Applicants to segregate the benefit of the lower FIT resulting from the TCJA and apply it to the benefit of customers. The Commission rejects the Joint Applicants' contention that, because they are under-earning their authorized returns, they should have to refund none of the tax benefits of the lower FIT to customers. This approach would be unreasonable. The TCJA's passage was an extraordinary and unanticipated event, outside the utilities' control, and results in a material reduction in the cost of service. See *In the Matter of NorthWestern Energy's Petition for an Accounting Order Authorizing the Deferral of the Expense-Related Portion of the Costs Associated with Phasing in its Natural Gas Transmission Integrity Verification Program,* Order 7528a, Docket D2016.11.88 (Feb. 21, 2017); *NorthWestern Energy - Request for Accounting Order Authorizing the Accumulation of the Cost of Funding Participation in Northern Tier Transmission Group*, Order 6829, Docket D2007.4.39 (May 15, 2007); *MDU-Application for an Accounting Order*, Order 6840, D2007.5.57 (July 3, 2007). The Commission provided notice of the possibility of this adjustment before Jan. 1, 2018, when the law became effective, and the Commission accepts MCC's arguments that it is reasonable that customers benefit from the tax overhaul. The Commission expects that if Congress had instead passed a significant corporate tax increase, it would have precipitated requests of the Commission to adjust rates in the other direction, including the possibility of deferrals dating to the effective date.

48. One way to estimate what consumers are paying for a utility's income tax expense is to take that portion of the last approved revenue requirement which was associated with this

expense. The total benefit of a reduction in the income tax rate could then be calculated by applying to that expense the ratio of 1) the difference between the new and old FITs, and 2) the old FIT embedded in the last-approved revenue requirement. This benefit calculation could be reasonable because it is based on the tax expense used to set existing rates. This approach was anticipated by the Commission. Not. Comm'n Act. (Jan. 22, 2018). However, the Notice also permitted the utilities to propose alternative proposals to appropriately calculate the amount of the deferral.

49. The Joint Applicants contend this methodology does not capture the utilities' actual performance and tax liability in a given year, and they also contend that their performance varies over the course of the year. Here the Commission is unpersuaded by the former contention. The Commission, however, believes the Joint Applicants raise a valid point regarding the variance in performance over the course of the year, which makes an annualized revenue requirement a poor fit for calculating a proper deferral. The Commission acknowledges that, as gas utilities make substantially all of their sales during the winter heating season, the Joint Applicants may be assumed to earn most of their taxable income during this time. Given the fact that the new rates established in this docket will be in effect for three colder months of 2018, the Commission would have to prorate the revenue requirement effect to account for weather-related sales. There is no clear way to do this based on the evidence in this proceeding. Therefore, the Commission accepts as a second-best solution the Joint Applicants' deferrals as they propose to calculate it, subject to a compliance filing due simultaneously at the time of the Joint Applicants' first GIRC Plan.

50. The Commission finds it appropriate to apply the benefits of the TCJA to the cost of GIRC, including both the deferral starting January 1, 2018, forward to the effective date of the new rates, and the EDIT. Although GIRC will not begin until 2019, the Commission finds it appropriate to apply the 2018 EDIT amortization and the partial-2018 FIT reduction benefit to the costs of the first year of the GIRC, and to use the ongoing EDIT amortization as part of the GIRC funding stream in a way that otherwise matches the year's EDIT to the year's GIRC spending. This allocation results in zero-cost capital to the GIRC because it is being paid for by the money that would otherwise go to the customer. No return on those funds will be earned by the utility, resulting in the most efficient and least harmful financial impact for ratepayers and the utility. The Commission finds these adjustments to be just and reasonable, and directs the Joint

Applicants to incorporate them into the utilities' revenue requirements accordingly.

Southern Montana Electric Pipeline

51. In 2010, SME built 19 miles of 12" high-pressure distribution main pipeline to provide fuel to SME's power plant, the Highwood Generating Station (HGS). Test. Degenstein 11; Test. Henthorne 11. In its negotiations with landowners housing the pipeline, SME agreed to provide natural-gas distribution facilities at no cost and to provide them with natural gas services. Test. Degenstein 12. EWM was hired to construct and operate the pipeline for SME. *Id.* The original cost of the pipeline was approximately $5 million, which EWM incurred and billed to SME, and SME paid a majority of the costs prior to bankruptcy. *Id.* at 13; Hr'g Tr. 81:20-82:4 (around $125,000 did not get paid through the bankruptcy). As a result of SME's bankruptcy, EWM negotiated the purchase of the SME pipeline for $75,000 in March 2016. Test. Degenstein 13; Test. Henthorne 10. Neither SME nor EWM had on file a tariff for the service of gas to consumers from this pipeline.

52. EWM contends that the original cost of the pipeline to SME should bind the Commission to accepting this value. It argues the Commission "needs to determine if it should continue its past practices of using the original cost standard or if it should depart from that practice and reduce rate base by including some or all of the negative acquisition adjustment" from the pipeline purchase. Test. Loy 42. Further, the utility argues, because it purchased the pipeline as an operating unit that had been placed in public service prior to the purchase, the FERC Uniform System of Accounts requires the plant to be recorded at the original cost to the person first devoting it to public service. Test. Henthorne 11. Accordingly, EWM requested that rate base include the original cost of the pipeline to SME, approximately $5 million, less depreciation, arguing the $75,000 purchase price does not reflect the true economic value or the original cost of constructing the pipeline. Test. Degenstein 13; Test. Henthorne 11-12. Since EWM purchased the pipeline in the middle of this rate case's test year, the rate base amount the utility proposes is an average of the beginning and ending balance of the 13 months that span the test year, equaling $2,009,102. Test. Henthorne 11, Ex. JDH-EWM-6 at 2. Nonetheless, the Commission interprets EWM's initial request, putting aside temporal accounting issues, to be a request to find as used and useful the full cost to SME of the pipeline, and not EWM's purchase price of it. Notably, EWM does not submit any of the books and records of SME to substantiate

the supposed original cost of the pipeline. Instead, EWM relies on Mr. Degenstein's recollection of what EWM invoiced SME for the work. Hr'g. Tr. 80:15-23.

53. In order to obtain approval of this asset in rates, EWM must not merely substantiate its cost, but it also must demonstrate that this asset is used and useful. To do so EWM posits two reasons. First, EWM argues SME was the first person to put the pipeline into public service by allowing others to be served by the pipeline from its inception, "because the pipeline became a necessary part of the distribution system required to serve retail customers, regardless of the actual load on the pipeline after it was placed into service." DR PSC-089(c) (Feb. 8, 2018). Since EWM bought it, EWM's use of it has grown, and the pipeline now provides the capacity necessary to serve over 250 customers. Test. Loy 43. Second, EWM also argues the SME pipeline is essential to providing safe, reliable, and uninterruptible service to the City of Great Falls by providing a redundancy that will accommodate future improvements to EWM's core system. Test. Degenstein 12; Test. Loy 42.

54. The MCC disagrees, arguing that SME did not devote the pipeline into public service, rather allowing its contractor, EWM, to provide retail gas service with the pipeline, which was incidental to the SME's primary purpose for the pipeline: to provide gas to the now-defunct HGS. Hr'g Tr. 45:18-19. According to the MCC, the original-cost standard holds that rate base should be measured on the "cost of the property to the person first devoting it to public service." Test. Schulz. 6; *see* 18 C.F.R. § 201 (2018). Accordingly, the MCC argues that since SME built the pipeline "for SME's power generation facility," although it allowed EWM to provide service to certain landowners, at no cost, it wasn't until EWM purchased the pipeline that it became devoted to public service, and therefore EWM's purchase price of $75,000 is the original cost. Test. Schulz 6-7 (quoting Test. Degenstein 11-12).

55. The MCC's witness, Paul Schulz, testified that in order for an acquisition premium to have merit, the acquisition must be the least-cost alternative, and in this case, any amount over what EWM actually paid would not be a least-cost alternative. Test. Schulz 7-8. The MCC argued that development of the SME project negated the need to consider an independent EWM project to provide similar system benefits. Test. Schulz 11. Absent the bankruptcy of SME, EWM customers would be enjoying the benefits of the SME pipeline at no additional capital cost, rather than the $75,000 paid by EWM to acquire the pipeline or the amount requested by EWM for rate base. *Id.*; Hr'g Tr. 378. Schulz argued that assessment of

positive and negative acquisition premiums is not symmetrical: the exclusion of positive acquisition premiums from rate base is not the same as allowing the creation of phantom investor capital when the price is below book. *Id.* at 7-9. According to Schulz, the FERC policy on acquisition premiums ensures that ratepayers will not incur higher rates solely because of a change in ownership of an asset or entity. In the case where price is less than original cost, FERC has limited cost recovery to the purchase price. *Id.* at 9 (citing *Ameren Corp*., 147 F.E.R.C. 61,224, 62,282 (2014)).

56. Schulz stated that rate base is intended to reflect investor-supplied capital and that reductions to rate base are commonly made for customer advances and contributions, and accumulated deferred income taxes, and in the case where a utility has acquired an asset at a cost above book value, the acquisition premium is contributed by utility investors, and this is not the same as the case where the asset is acquired at a price below book value. *Id.* at 9-10. Schulz applauded EWM for taking the opportunity to purchase the SME pipeline at a steep discount from book, but stated there is no advantage to EWM customers if that discount is wiped out and shouldered by ratepayers as a phantom amount added to rate base. *Id.* at 10.

57. MCC witness Hill testifies that placing the $5 million that the pipeline cost SME into EWM's rate base would allow EWM to earn a return that is far higher than its own cost of capital or that of comparable enterprises. Test. Hill 45 (Feb. 22, 2018). He argues that while a utility is entitled to a return similar to ventures of comparable risk, it "has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures." *Id.* (citing *Bluefield Water Works & Imp. Co. v. Public Service Commission*, 262 U.S. 679, 692-3 (1923)). Hill argued that if EWM earned the MCC recommended after-tax return on EWM's requested SME pipeline increase to rate base, i.e., 6.62% on $2.1 million, the $130,000 in annual income would represent a 177% return on the actual investment of $75,000. *Id.* at 45-46. He considers this return inappropriate for a utility operation, arguing the $4.9 million original cost of the pipeline is not cost justified by the addition of 200 new customers. *Id.* Further, Hill argues the additional revenues from new customers could provide the utility with an adequate return and that EWM's proposal to "rate base" the SME pipeline at a value of $2,009,102 would allow EWM to double-recover the cost of building the line. *Id.* at 47.

58. In rebuttal, EWM submitted a revised accounting proposal for the SME asset proposing to recover a return of the original cost to SME, rather than a return on the same. Such a proposal takes the form of depreciation included in the cost of service, and would cause an amortization of the negative acquisition adjustment below the line in other income, rather than to enter net original cost into rate base. Rebut. Test. Henthorne 12-13. This revised accounting entered net plant of $59,796 into rate base, which is the difference between original cost and the negative acquisition adjustment, adjusted for accumulated depreciation; this value is averaged over the test year to produce a rate base effect of $29,898. *Id.* at Ex. JDH-EWM-19. EWM also depreciated an amount of $4,830,867, or the original cost of $4,905,867 less the purchase price of $75,000, and from this function, depreciation expense of $90,579 is included in the revenue requirement. *Id.* Finally, EWM would amortize the negative acquisition adjustment of $(4,094,985), and the amortized amount of $(76,781) is not requested to be included in the revenue requirement. *Id.*

59. As more fully explained below, the Commission rejects EWM's position. The Commission has regulated service that is incidental to other nonregulated uses of natural gas transportation, distribution or gathering infrastructure. *In the Matter of Havre Pipeline Company's Service Quality and Its Response to Notice of Commission Action in N2014.11.92*, Order 7413b, Docket D2015.3.32, ¶¶ 6-9 (Feb. 23, 2016) (finding a gas gathering system is a public utility service and that system is subject to Commission regulation). However, this does not mean that whatever it cost to build the SME pipeline, which was primarily intended to serve an unregulated natural-gas fired electric power plant, must be the cost accepted as the "used and useful" value that this Commission enters in rate base when the original purpose has become defunct and it is left a stranded asset, serving only a shadow of its purpose. No regulatory commission ever accepted that the pipeline was "useful" in the economy and, indeed, SME's bankruptcy suggests it was not. The value of the property is to be determined as of the time when the inquiry is made regarding the rates and is not a matter of formulas, but must be based on fair and enlightened judgment in proper consideration of all relevant facts. *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 690-92 (1923). The bankruptcy court, in permitting the sale or auction of SME's assets, afforded to other parties rival economic uses—other than simply salvaging it for metals—and the proper value of that use was established by EWM's winning bid. Indeed, as described by EWM's lead witness' own words, this bid reflects

the value the utility placed on it at the time it was purchased. Degenstein called this winning bid a good investment and the "right price" at the hearing: "$75,000 was all I was willing to spend because ultimately we shouldn't spend money that we don't need to spend . . . we had the right price." Hr'g Tr. 48:4-20, 49:17-21. "I would not have paid 4.9 million. . . The right decision was to get the best cost, the best price for the utility and the ratepayers of Montana." *Id.* at 49:4-12. The Commission notes a more proper lens of inquiry would be to ascertain what, within the bankruptcy, would have been the likely salvage value of the pipeline, since that appears from the record to have been, other than its attachment to EWM's pre-existing utility system, its only rival economic use. However, the Commission will not gainsay $75,000.

60. Relatedly, EWM's arguments that it faced a need that, without the SME pipeline, would have eventually caused a greater investment, are irrelevant. The Commission does not authorize rates for the cost of sub-optimal solutions to problems; it expects utilities to solve them in the most cost-effective manner possible, in this case by acquiring a pipeline from SME, after the City of Great Falls already had paid dearly for SME's bankruptcy. If the pipeline had not been purchased opportunistically by EWM, it may have been a completely pointless loss. Hr'g Tr. 83:12-85:13.

61. The Commission's decision largely moots the question of whether the asset had a public service purpose before its value, as a matter of first impression, was presented to this Commission. However, even if the Commission were not to view the situation in the light of the "used and useful" value of an asset, EWM has not met its burden of proof for establishing an original cost basis of the pipeline. It has presented none of the books and records of the entity that is said to have devoted it first to public service. It relies only on what EWM itself, as a contractor, was paid by SME for the work of constructing the pipeline. Test. Henthorne 13. EWM retained this money, applying it not just to capital costs of constructing the pipeline but also returning some portion of that money to itself as profit or to offset other operating expenses. *Id.* at 11. Thus, even if the Commission were to accept an original cost based not on public utility records but on a contractor's estimate of what it is was paid, the Commission would also have to account for what contribution in aid of construction were made to offset utility investor-contributed capital for this project. As EWM acknowledged, SME's focus for the pipeline was private use for its power plant, HGS. *See* Hr'g Tr. 45:18-19. The HGS payment to EWM should be accounted for as customer-contributed capital, offsetting the project's cost and discounting it

to a value which could then be allocated for the purposes of public utility regulation. Since the proposed cost to be included in rate base equals what EWM was paid for its work, this would properly result in a rate base of exactly $0. It seems much fairer to the Commission to pay EWM exactly what, in SME's bankruptcy, it actually paid for this asset.

62. The Commission finds that rate base should reflect the $75,000 for which EWM purchased this asset in bankruptcy, adjusting for ratemaking conventions based on average test-year balances and any accumulated depreciation.

Upstream Capacity Costs (MDDQ proposals)

63. EWM pays NorthWestern Energy ("NorthWestern") for upstream capacity and commodity transmission costs to deliver gas to all of its customers, including full service, distribution transportation, large commercial, and negotiated contract customers. In turn, upstream costs are shared by all customers. Upstream capacity costs are determined by the Maximum Daily Demand Quantity ("MDDQ") that EWM requires from NorthWestern.

64. Negotiated contract customers pay EWM for this capacity according to agreements in their respective contracts. Large commercial customers pay according to a two-tier system established in tariff. Customers with daily metering capability or purely interruptible volumes at the time of the last rate decision pay for MDDQ requirements and contribute additional payments for volumes exceeding daily MDDQ. Pasta Montana and Great Falls Sand and Gravel are the only customers using Option 1 of the tariff. A second option is currently available to Benefis Hospitals ("Benefis") since they did not have adequate daily metering when Order 7132c was issued. Under Option 2, Benefis pays a transport rate (capacity and commodity) that equals 80% of the extended general service tariff rate excluding storage costs. *See* Order 7132c, Docket D2010.9.90 (Nov. 17, 2011).

65. EWM proposes three modifications to improve the allocation of upstream capacity costs. First, EWM adds language to the Large Commercial and Negotiated Contract class tariffs to reset a customer's MDDQ to the new level if contract MDDQ is exceeded. Second, EWM adds language requiring a new customer requesting service under either of these tariffs to address its MDDQ needs, so that EWM may consult with its transportation provider–NorthWestern–regarding acquisition of new capacity before granting service. Third, because Benefis now has daily metering capability, and EWM's analysis shows that it is likely they could save money by switching to Option 1 of the Large Commercial tariff, EWM will discuss that

issue with Benefis in the near future. These issues were not contested by MCC. Test. Henthorne 31.

66. The Commission approves EWM's proposals to reset MDDQ and review the MDDQ needs of new customers on the Large Commercial tariffs. Regarding its third proposal, the Commission finds that termination of Option 2 in the Large Commercial tariff is appropriate. Benefis now has daily metering capability, so it is reasonable to track and cost daily volumes up to and in excess of contract MDDQ. Under Option 1, the rate structure passes through all transportation costs EWM incurs up to daily volumes equaling contract MDDQ. Volumes in excess of contract MDDQ are charged at a rate equal to the rate EWM pays NorthWestern for commodity transport, plus 75% of the difference between that rate, including ancillary volume charges, and the extended general service customer transport rate excluding storage costs. Order 7132c ¶ 142. The Commission finds elimination of Option 2 would simplify the tariff and implement standard treatment of comparable customers.

Modification to collection of PSC/MCC tax expense for EWM

67. EWM currently collects its PSC/MCC tax expense as part of its base charge and volumetric rate distribution rate. Hr'g Ex. JA-4, 26:5-6. EWM has proposed to collect the tax cost on a per CCF basis through a separate rate component in EWM's tariffs. Hr'g Ex. JA-4 26:6-14; Test. Henthorne, Ex. JDH-EWM-8 and Ex. JDH-EWM-10. The requested method is the same method used by CBGC. MCC did not contest the proposal. The Commission approves this method and finds in favor of adopting the EWM/CBGC proposal and directs the Joint Applicants to file compliance tariffs, accordingly. *Infra* ¶ 170.

Line Extension Tariff

68. EWM's distribution main extension allowance is $500 per residential customer and a 5-year simple payback calculation for other customers. Add. Issue Test. Henthorne 3 (Mar. 30, 2018). EWM will provide the service stub from the main to the customer's property, and is responsible for the cost and installation of meter and regulators. *Id.* The customer is responsible for all other installation costs. *Id.* Under this policy, no incremental costs are passed to existing customers when new customers are attached. *Id.* at 4. EWM recovers the costs of the free allowances in base rates from new customers. Incremental costs exceeding free allowances are recovered through Contributions in Aid of Construction ("CIAC"). *Id.* at 6. In instances where the CIAC may be so large as to discourage expansion, Rule 17 of the tariff permits an area

rate for a subdivision or group of customers, subject to approval by the Commission. *Id.* An area rate for a subdivision or large group of customers should be structured for recovery over time rather than requiring CIAC to cover all costs exceeding the allowance immediately. *Id.* at 8. CBGC doesn't have a written line extension policy, but generally follows EWM's policy. CBGC will adopt any changes the Commission orders in EWM's policy. *Id.* at 2.

69. EWM proposed to offer a new extension allowance for installation of services between the service stub and the house. *Id.* at 10. EWM currently charges residential customers $300 for the first 50 feet of service line, and $5.50/ft. thereafter. *Id.* at 10. For non-residential customers (2" line), EWM charges $400 for the first 50 feet and $6.50/ft. thereafter. *Id.* at 10-11. EWM proposed to offer a free allowance to install the first 100 feet of service line. Street cuts and excessively rocky conditions would still require customer contribution. *Id.* The allowance value to customers for a 100' service line is $575 for standard service and $725 for 2" line. *Id.* This proposal was not contested by MCC.

70. An infinite lifeline extension allowance is derived using the perpetual net present value method.[1] The allowance equals the net present value over an infinite period of the expected net margin provided by a customer, as an approximation to the marginal value of a line extension over a lifespan of 50 years or more. The infinite life assumption reduces the calculation to the ratio of annual net distribution margin to pre-tax cost of capital or rate of return. Thus, if a customer is expected to contribute margin of $300 annually, and the pre-tax cost of capital is 10%, the extension allowance would be $3,000. EWM testified that it would not support an infinite line allowance, as it ignores the incurrence of added O&M costs required to serve additional customers, and because pre-tax cost of capital is not sufficiently stable to use in an infinite life calculation. DR PSC-010(a) (Nov. 29, 2017).

71. Using an economic carrying charge rate of 7.70%, EWM calculated the incremental cost in main allowance, service stub allowance, meter, regulator, and customer service to equal $110 per year for residential customers. Add. Issue Test. Henthorne, Ex. JDH-EWM-16 at 1. The incremental cost to non-residential customers is $1,338 per year. *Id.* at 2. The

[1] *Line Extensions for Natural Gas: Regulatory Considerations*, by Ken Costello. February 2013, National Regulatory Research Institute. See page 20.

proposal for a new service allowance would increase the incremental cost to $154 per year for residential customers, and $1,394 for other customers. *Id.*

72. EWM testified that line extension and fuel switching may provide societal or public benefits such as economic development, but these benefits are hard to quantify. If existing customers do enjoy measurable system benefit from line extension, there is no reason why they should not pay a share of the costs commensurate with the benefit. Further, EWM argued that that structuring EWM's rate design so that revenue recovery is more stable and less dependent on usage would enhance EWM's opportunity to recover line extension costs; another reason to support increased customer charges. Add. Issue Test. Henthorne 5, 7.

73. According to EWM, main extensions are typically sized to accommodate growth, so the incremental capacity typically exceeds the incremental peak load of new customers. *Id.* at 7-8. The cost of the extra capacity may be recovered in a rate case before the anticipated growth occurs, so that existing customers are paying for a share of incremental capacity. *Id.* at 8. EWM does not consider this a permanent harm to existing customers, as payments today will be offset in time by the benefits of future growth. *Id.*

74. In response to discovery, EWM submitted cost studies regarding extension of service to Belt and Sand Coulee. DR PSC-146 (Apr. 17, 2018). The total cost to extend service to Belt is $1,765,738. *Id.* at DR PSC-146(b) at 7. Total allowance including the proposed service allowance is $375,203, and required CIAC is the residual $1,390,535. *Id.* EWM calculates the all-in area rate including gas costs would be $18.15/Dkt for residential customers assuming simple 5-year payback, compared to a $20/Dkt cost of propane. *Id.* If extension allowances were increased to the ratio of annual margin and a 10% pre-tax cost of capital, the all-in rate for residential customers would decrease to $16.54/Dkt. *Id.* at PSC-146(c), Attach. at 2.

75. The all-in rate includes the current distribution rate for Great Falls-Cascade customers, a surcharge to recover the shortfall (total project cost less allowances), and a surcharge to collect incremental A&G and O&M costs associated with the investment. It does not include commodity, transportation, or ancillary rates, and doesn't include fuel transition costs on the customer side of the meter. Thus the all-in rate understates the total customer cost associated with service extension and fuel switching.

76. The total cost to extend service to Sand Coulee is $214,922, with allowance of $72,147 and required CIAC of $142,775. DR PSC-146(b), Attach. at 3. EWM calculates the

all-in area rate including gas costs would be $11.53/Dkt for residential customers. *Id.* at 3. If extension allowances were increased to the ratio of annual margin and a 10% pre-tax cost of capital, the all-in rate for residential customers would decrease to $9.87/Dkt. DR PSC-146(c), Attach. at 4.

77. EWM believes that extending service to Belt is not economic, because the cost is too great and the number of customers and total volumes are too small. DR PSC-147 (Apr. 17, 2018). Even under current low natural gas prices the area rate required would make the cost about equal to propane. *Id.* EWM plans to extend service to Sand Coulee in 2018, using funds committed in Docket D2015.1.11, Order 7399a ¶ 19. *Id.* Remaining funds will not permit a similar extension to Belt. Hr'g Tr. 173:20-174:10.

78. EWM states that calculating residential customer allowance as the ratio of annual distribution margin and a 10% pre-tax cost of capital would require existing customers to cover part of the cost of extending service to a new customer. DR PSC-149(b) (Apr. 17, 2018). Calculating the allowance for non-residential customers with annual margin of $3,000 in this fashion would reduce the customer contribution to fixed cost recovery to $507 from the $1,616 contribution under the current allowance. *Id.* at PSC-149(c).

79. At hearing, EWM testified that although it "probably violates everything we talked about earlier about new customers and old customers," it might be possible to fold Belt customers in with the Great Falls customers, similar to the extension to Cascade, and perhaps the impact on the Great Falls customers would not be excessive. Hr'g Tr. 177:8-16.

80. MCC testified that the Commission should provide EWM a reasonable opportunity to recover costs associated with line extensions, but should not guarantee recovery of these costs. Add. Issue Test. Donkin 2-3 (Apr. 24, 2018). MCC does not support the use of a tracker to recover costs, arguing a tracker would be a single-issue regulatory device that violates the matching principle. *Id.* at 3. It is the MCC's position that the Commission should not approve EWM's proposed increases to customer charges in an effort to improve its ability to recover incremental line extension costs, because EWM presently has a reasonable opportunity to recover these costs. *Id.* at 6.

81. Free line-extension allowances may be used to award the customer a CIAC benefit for his contributions to net margin, that is, a calculation of customer contributions to fixed costs after deducting the incremental costs of serving the customer. These costs may

include property taxes, return of depreciated investment, debt service, and other A&G and O&M costs. Allowances may also be used to encourage the extension of service to new areas where future growth opportunities or other benefits provide value to existing customers or society. In this case, EWM is proposing to increase residential and commercial allowances to include allowance for installation of service lines, and the MCC did not contest this proposal. The Commission approves the Joint Applicants' proposal for the line extension tariff.

82. EWM also calculated infinite life allowances for customers. However, the calculations appear to use gross rather than net annual customer contributions to margin. The record is not clear why the calculations were performed this way, and how an alternate calculation of infinite life allowances using contributions to net margin may affect the utility's ability to recover prudently incurred costs. The record is sparse regarding external benefits that may be obtained through extension of service to Belt or other communities. EWM did testify that it expects little future population growth in Belt. DR PSC-148 (Apr. 17, 2018).

83. The record in this case does not support adoption of a change to Rule 17.1 that permits or directs the use of infinite life allowances. If the Commission or any party wishes to investigate the merits of alternative methods for calculating free main extensions, the investigation can be pursued in a generic non-contested docket, or in a future rate case.

Main Extension Service to Belt, Montana

84. Main extensions are regulated under Rule 17 of the tariff. Rules 17.1 and 17.3 would apply to extension of service to Belt. Rule 17.1 describes the free allowances available for main extensions. Rule 17.3 requires that applicants provide CIAC to cover the difference between the total estimated project cost and available allowances, or that applicants shall be assessed an incremental surcharge or area rate on volumes. The area rate and time period are determined by the Commission. The area rate is set to pay down the balance of utility investment, so this option essentially allows customers to provide CIAC on a term plan.

85. EWM examined three cost-recovery options for extending service to Belt, a five-year area rate with EWM proposed allowances, a five-year area rate with infinite life allowances, and traditional recovery of investment. For the area rate options, costs in excess of the initial allowance would be recovered through an area rate that would provide CIAC. After five years, the CIAC is designed to offset the shortfall so that the initial investment entered into rate base in the next rate case would be limited to any undepreciated allowances. The traditional option

isolates Belt investment to be depreciated through separate surcharge over 40 years. DR PSC-146.

86. Using Commission-ordered rates and returns, staff recalculated five-year area rates under the proposed and infinite life allowance options, and using traditional rate methods. The Commission agrees with EWM that if extension costs net of proposed allowances are imposed entirely on Belt customers, it is not certain that enough customers will find the offer attractive to make the build-out feasible. The Commission estimates the total rate will exceed $22 per dekatherm for residential customers, and since this cost does not include costs on the customer side of the meter, the savings will be significantly negative for five years under the model. After five years, assuming customer participation is consistent with expectation, the investment shortfall and allowance would be largely depreciated through the area rate, so the remaining balance could be rolled into Great Falls - Cascade rate base without significant disturbance. In that event, Belt customers would receive service at rates consistent with other Great Falls customers. However, it is not clear why EWM uses five years, instead of another period of time, as the threshold

87. If extension costs net of infinite life allowances are imposed entirely on Belt customers, the build-out is more attractive to customers, but savings remain negative over five years for all customers except for the school. For reasons described above, adoption of infinite life allowances is not well supported in the record. It is not clear that the calculation used in this case defines the present value of net contributions to margin, as it should.

88. Foremost, the traditional rate based recovery option generates positive savings for customers, excluding household upgrade costs. However, these results rely upon a propane unit cost of $20/Dkt, and a transport/supply cost for natural gas of just over $3/Dkt. This relation may not hold over 40 years. EWM believed this option would not be attractive to many customers. Since EWM does not support any of these options, and because each of these options exposes the utility to risk of under-participation with consequent cost under-recovery, the Commission will refrain from ordering any of these options until the utility establishes firm, enforceable commitments from customers.

89. The Commission analyzed rolling Belt customers into the Great Falls - Cascade tariff. This choice would provide higher certainty of cost recovery for EWM, but would require significant contributions from existing customers.

90. The incremental rate applied to all customers would be about $0.085 per dekatherm. This would result in an increase of about $6 per year to existing residential customers, and $10, $74, and $520 per year for small, large, and extended general service customers. Increased revenues from robust customer and volume growth in the Belt area could potentially reduce rates for all customers in future rate proceedings, but as noted above, EWM currently expects little future population growth in Belt. DR PSC-148 (April 17, 2018).

91. All of the above analyses assumed a 70% participation rate for Belt customers. Due to the attractive savings associated with the roll-in option, the Belt participation rate may be higher, resulting in a slight reduction in the estimated rolled incremental rate and incremental costs to existing customers.

92. The Commission approves the Joint Applicants' proposal to increase its free main extension allowance to customers to include a service line allowance. The Commission encourages EWM to continue investigating costs and benefits of a line extension to Belt, with particular emphasis on potential opportunities for economic development and expected contributions to capital cost from new customers.

Working Capital

93. EWM witness Henthorne includes $724,166 of cash working capital in rate base for EWM and $78,486 for CBGC, utilizing the 1/8 of test year average of actual annual operating and maintenance expense. Supp. Test. Henthorne 1 (Feb. 26, 2018). MCC's witness Schulz has concerns regarding working capital insomuch as not all expenses incurred by a utility to provide service are required prior to the receipt of revenues from customers, and believes two examples of this are property taxes and interest payments. Test. Schultz 24. He states that property taxes are paid in arrears, meaning the Company pays for those taxes after the time period they cover has passed. *Id.* at 24-25. Consequently, this represents a source of working cash for the utilities, not a use of working cash. *Id.*

94. Schulz states he had to determine the average time that EWM and CBGC, respectively, are in possession of that created working cash. *Id.*at 25. The Joint Applicants have slightly different intervals between meter reading and payment due date. DR MCC-063 (Jan. 31, 2018). Customers' meters are read, and customers are billed throughout the month, but this should average out overall as the meter reading periods are 25 to 35 days. *Id.* For EWM, the revenue to cover property taxes for the time January 1 to January 31 is typically received by

February 14. *Id.* For CBGC, the revenue to cover property taxes for January is typically received by February 20. *Id.* In the case of EWM, this means that EWM is in possession of the funds to pay January property taxes due to Cascade County on December 30 of the same year for 10.5 months, for February property taxes the expense lead is 9.5 months and so on. *Id.* EWM is then in possession of interest free funds in the amount of those property tax payments for an average of 8.01 months out of the year. *Id* at 26. Consequently, these funds reduce the working capital addition to rate base because they do not represent invested or borrowed capital for which the utilities should receive a return. *Id.* Schulz proposed to include in rate base for EWM $91,411 and for CBGC $57,970. Test. Schulz, Exs. PRS-6EW and PRS-6CB.

95. Henthorne states the Commission has accepted EWM's 1/8 of O&M method to calculate working capital in EWM's previous cases: D2010.9.90 and D2004.3.46. Rebut. Test. Henthorne 9. He states property taxes and interest expenses are not included in operating and maintenance expenses, therefore Schulz is making a reduction for amounts that are not included in EWM's calculation. *Id.* at 10. According to Henthorne, FERC provides guidance on the methodology for lead/lag studies, *see* CFR-2012-Title 18-vol.-sec.-154-312, and simple common sense indicate that a proper lead/lag study must consider all of the factors related to cash receipts and cash payments. *Id.* at 9. Picking two of the items delivers a result that is not complete and is inaccurate. *Id.*

96. Both EWM/CBGC and MCC provided testimony that neither is opposed to a lead lag study. Henthorne stated:

> Well, my understanding is there is basically two methods in the regulatory world of establishing a working capital allowance. One is the one-eighth of O&M method, which we use, and another one is a complete lead/lags study the taxes would be a portion of that, it ignores items on the other side so, you know, pre-paid items on the other side so, you know pre-paid items we've already put out money for that we're not collecting on. So my point is that if we're not going to doing a one-eighth of O&M, then we should do a complete lead/lag study and consider all of the sources and uses of cap.

Hr'g Tr. 154:2-16. According to Schultz:

> I certainly think it's worth consideration. The adjustment I made to working cash was an attempt to bring in significant sources of working capital to balance the ledger there without going to a full lead/lag study, recognizing there are expenses associated with that. However, I wouldn't be opposed to that. Yes, there would be costs to do it. No, I don't know exactly what the results may be. However, based on what we've seen, for example, with NorthWestern, it may very well be a

> reduction in working cash, not necessarily a - a total rate base reduction in terms of an actual deduct, but it just may be a lower amount for working cash."

Id. at 397:7-20.

97. Although the property tax and interest payments are not included in the working capital calculation itself, the two examples provided by Schultz are possible ways a firm can offset or reduce its working capital needs. The Commission finds utilizing the cash working capital amount as filed by the Joint Applicants is appropriate. The 1/8 method is a recognized methodology utilized to calculate working capital requirements.

98. In addition, the Commission notes the Joint Applicants have not provided a lead/lag study in the past 10 years. The affordability of the study and the fact that both parties agree such a study would be useful indicate that the Joint Applicants should provide such a study in any future revenue requirement filings.

Cost of Capital

Capital Structure

99. Gregory E. Scheig, Principal of ValueScope, Inc., filed testimony on behalf of the Joint Applicants regarding their proposed costs of equity ("ROE"), capital structures, and overall rates of return ("ROR"). Test. Scheig (Sept. 29, 2017); Rebut. Test. Scheig (April 9, 2018). Scheig's proposed capital structures for the Joint Applicants are based on the long-term debt and equity figures represented in their balance sheets as of December 31, 2016. Test. Henthorne 7, 33. Scheig considered the short-term debt a component of working capital to be repaid within a year and not a source of permanent financing, and therefore excluded it from his analysis. Rebut. Test. Scheig 19. He considered the proposed capital structures and calculated requested ROE for EWM of 10.75%, as reproduced in Table 3 below. Rebut. Test. Scheig 38.

Table 3

Cost of Equity Estimation Method	Indicated Cost of Equity	Weighting	Weighted Cost of Equity
CAPM	7.29%	5%	0.4%
ECAPM	7.69%	5%	0.4%
Modified CAPM	9.88%	10%	1.0%
Modified ECAPM	10.51%	10%	1.1%
Constant Growth DCF	8.96%	20%	1.8%
Non-Constant Growth DCF	10.51%	10%	1.1%
Risk Premium	9.57%	30%	2.9%
Expected Earnings	10.17%	10%	1.0%
Total Weighted Cost of Equity			9.5%
Additional Small Stock Risk Premium			1.25%
Total Requested ROE			**10.75%**

100. Scheig also calculated the Joint Applicant's requested ROR's of 8.32% (EWM) and 8.90% (CBGC), as shown in Exhibit (GES-2), Schedules I.1 and I.2, as reproduced in Table 4 below. *Id.* at 38-39, Ex. GES-2 at 80-81.

Table 4

EWM	% of total Capital Structure	Cost	Weighted Average Cost
Long-Term Debt	39.95%	4.66%	1.86%
Equity	60.05%	10.75%	6.46%
Total Requested ROR			**8.32%**

101. Stephen G. Hill, Principal of Hill Associates, filed testimony on behalf of the MCC. Hill uses his DCF analyses as his primary indicator of the cost of equity capital, indicating a range of 8.64%-8.74%. Test. Hill 42 (Feb. 22, 2018). He argues that due to uncertainty regarding the direction of the U.S. economy and interest rates, it is reasonable to utilize the upper end of this range for setting the Joint Applicants' rates in this proceeding. *Id.* at 43. Therefore, the MCC suggests an 8.75% allowed return on equity is reasonable and appropriately balances the interests of the Company and its customers, as reflected in Table 5 below. *Id.*

Table 5

Cost of Equity Estimation Method	Indicated Cost of Equity
Sustainable Growth DCF	8.74%
Mechanical DCF	8.64%
CAPM-vs. Long-Term Treasury total return	7.75%
CAPM-vs. Long-Term Treasury bond yield	8.50%
MEPR vs. 2017 Forecasted ROE	6.83%
MEPR vs. 2020-2022 Forecasted ROE	7.46%
MTB vs. 2017 estimated ROE, Retention Ratios	8.74%
MTB vs. 2020-2022 estimated ROE, Retention Ratios	8.79%
Total Requested ROE	**8.75%**

102. Hill's proposed capital structures for EWM and CBGC are based on the average capital structures of his proxy group companies. Test. Hill 19. He is critical of Scheig's decision to exclude short-term debt from his proposed capital structure and to use equity and long-term debt figures represented by the Joint Applicants, arguing they are a function of intercorporate capital allocations and not derived as a result of their relative risk interaction with the capital markets. Test. Hill 17. In contrast, the capital structures of the similar-risk sample group of gas utility holding companies which Hill relied on to estimate the cost of capital are a direct result of their relative risk and interaction with the capital markets. *Id.* Taking Hill's proposed capital structure and the requested return on equity of 8.75% (see Table 5 above), the MCC's requested rates of return (6.62% (EWM) and 6.42% (CBGC)) can be seen below in Table 6.

Table 6

CBGC	% of total Capital Structure	Cost	Weighted Average Cost
Long-Term Debt	43.25%	4.31%	1.86%
Short-Term Debt	7.32%	3.13%	0.23%
Equity	49.43%	8.75%	4.33%
Total Requested ROR			**6.42%**

EWM	% of total Capital Structure	Cost	Weighted Average Cost
Long-Term Debt	43.25%	4.66%	2.02%
Short-Term Debt	7.32%	3.77%	0.28%
Equity	49.43%	8.75%	4.33%
Total Requested ROR			**6.62%**

103. Hill contends that these returns will allow EWM an opportunity to earn 3.6 times its pre-tax interest coverage and CBGC an opportunity to earn 3.8 times its pre-tax interest

coverage, which in turn will afford the Companies an opportunity to maintain their financial position and attract capital, as required by Hope and Bluefield. *Id.* at 44.

104. The Commission did not consider whether to include short-term debt in the company's capital structure in EWM's last rate case in 2010. *See* Docket D2010.9.90, Order 7132c (Nov. 17, 2011). In that docket, EWM and the MCC both recommended capital structures that excluded short-term debt, and the Commission adopted such a capital structure (CBGC was not a party).

105. The Commission disagrees with Hill that short-term debt should necessarily be included in the capital structure. Short-term debt may finance spending that is not part of rate base. It would seem such borrowing should not be reflected in the capital structure. However, EWM has proposed, and the Commission has approved, a discrete rate base value of approximately $2.6 million for natural gas held in storage, on which it will earn a return. Rebut. Test. Henthorne, Statement E - Working Capital (Apr. 6, 2018). At hearing, the Joint Applicants conceded that the utility uses short-term debt, or a line of credit, to finance these purchases. Hr'g. Tr. 155:17-24. When the utility earns a return on an asset by including it in its rate base, as the Commission allows here, the cost of financing these purchases should be reflected in the approved capital structure. Not doing so would effectively impute a return on this asset that reflects higher-cost debt and equity financing.

106. The Commission calculates that 4.25% is the effective rate for short-term debt under the utility's line of credit, reasoning that 4.25% was the average interest rate paid on the line of credit during the test period and that, consistent with its discussion of interest rates below, the rate for the line of credit is also likely to rise. The short-term debt cost of 4.25% is less than either the cost of long-term debt or the cost of equity, either as proposed by the Joint Applicants or approved by the Commission in this Order. The inclusion of short-term debt results in a slightly lower cost of capital primarily because it results in the capital structure being less weighted toward equity.

107. In this Order, the Commission is also making two disallowances to rate base which should be considered in the capital structure. *Supra* ¶¶ 22-31 and 51-62. In rebuttal, EWM changed its position on including the SME pipeline as part of rate base and withdrew its request to earn a return on the asset's supposed value. Rebut. Test. Henthorne 12-13. The effect of this request, without a further adjustment to the capital structure, is to implicitly contend that both

equity and debt were used to "finance" the withdrawn value. Meanwhile, the approximately $1.0 million disallowance related to SAP, which the Commission makes by this order, involves an actual capital outlay that the utility would somehow have had to finance. *Supra* ¶¶ 22-31. Here, where real money is being spent, it seems reasonable to assume that the company invested in the disallowed SAP-related costs using the proceeds of long-term debt and equity in a ratio proportional to those elements' weight in the company's overall capital structure.

108. For these reasons, EWM's proposed capital structure is not reflective of the plant the utility earns an authorized return on, and the Commission finds it should be corrected. Hill proposes a hypothetical capital structure based on an average of the proxy group. Test. Hill 19. The Commission instead finds that because of the substantial amount of rate base that is financed through short-term debt, it is reasonable in the case of EWM to use a capital structure that reflects the company's actual financing scaled to rate base, net of the adjustments described above. The Commission accomplishes this calculation as follows. First, the Commission accepts the approximately $11.4 million and $7.6 million in equity and long-term debt reported by the company. Test. Scheig 29. To this, the Commission adds approximately $2.6 million, which reflects the amount of natural gas inventory in storage, as it is reflected in rate base. Test. Henthorne, Ex. JDH-EWM-9, Rule 38.5.142. This sums to approximately $21.6 million, which must be reconciled to the final submitted rate base value of $18.5 million. The Commission scales the former to the latter by reducing the shares of long-term debt and equity in a proportionate share; it does not reduce short-term debt, because this is the only part of financing that is directly tied to a discrete asset, and a scalar would therefore be inappropriate. Thus calculated, long-term debt and equity have been scaled to approximately $6.3 million and $9.5 million, respectively. Together with short-term debt, this sums to the final submitted rate base value of $18.5 million. This amount then must be reduced to reflect the Commission's disallowance of part of the SAP asset, consistent with the Commission's reasoning above. *Supra* ¶ 30. This results in a total rate base of approximately $17.5 million, with a final long-term debt and equity in the amounts of approximately $5.9 million and $8.9 million, alongside approximately $2.6 million of short-term debt.

109. Meanwhile, CBGC proposes a capital structure which reflects 71 % equity, with the remainder long-term debt. Test. Scheig, Ex. GES-2, Sch. 1.2. Approving such an equity-thick capital structure is not reasonable, as the Commission previously found with respect to EWM

when it asked the Commission to approve a capital structure with 73 % equity. Order 7132c, ¶ 93. In this proceeding, CBGC has identified no other gas utility with a comparable capital structure. Like it does for EWM, MCC recommends establishing a hypothetical capital structure based on the industry proxy group, including short-term debt. However, CBGC does not include natural gas inventory, financed by short-term debt, in its rate base; making such an imputation would be inappropriate. Instead, the Commission will establish a capital structure of 55% equity with the remainder long-term debt. This is consistent with the industry proxy group that Scheig presents when short-term debt is excluded, as it properly is with respect to CBGC. Rebut. Test. Scheig, Ex. GES-1R at 81. It also is consistent with the finding that a 55% hypothetical equity ratio falls within the range of reasonableness, pursuant to Commission precedent. Order 7132c ¶ 94.

110. Consistent with the discussion above, the Commission approves the following capital structure for EWM:

Table 7

Energy West	Dollar Amount of Rate Base	Capital Structure Percentage	Cost	Weighted Average Cost
Long-term Debt	$5,935,207	33.91%	4.66%	1.58%
Short-term Debt	$2,647,418	15.12%	4.25%	0.64%
Equity	$8,921,126	50.97%	9.20%	4.69%
Total	$17,503,751	100.00%		6.91%

As described above, the cost of EWM's short-term debt is 4.25%. Further, the cost of long-term debt is presented by Scheig and not disputed by Hill. The cost of EWM's long-term debt is 4.66%, and 4.31% for CBGC.

Cost of Debt

111. As described above, the cost of EWM's short-term debt is 4.25%. The cost of long-term debt is presented by Scheig and not disputed by Hill; it is 4.66% and 4.31% for EWM and CBGC.

Base Cost of Equity

112. The remaining 51% and 55% for EWM and CBGC's capital structures, respectively, are equity. The cost of equity is a vigorously contested issue in this proceeding, because unlike long-term debt which is priced based on transparent agreements between the

utility and a third-party issuer, the cost of equity is estimated based on expectations of what equity investors demand in return for the time-value of their money and the risk of the investment at hand. The Commission will more thoroughly examine the ROE in this Order than it has in previous orders in the hope that its resolution will indicate a starting point for the Commission's jurisprudence for parties to future rate cases.

113. The Joint Applicants present eight separate methodologies, with various permutations of data input, for a sum total of 24 different results for ROE, each of them given a different weighting by the Joint Applicants' witness, Scheig. Test. Scheig, Ex. GES-2 at 1. Hill presents a smaller set of analyses, and focuses on a variant of a methodology presented by Scheig, the sustainable growth Discounted Cash Flow ("DCF") method. Test. Hill 20, 66.

114. The evidence in this proceeding has convinced the Commission that Empirical Capital Asset Pricing Model ("ECAPM") should be the primary method for estimating the Joint Applicants' cost of equity in two different variations, as explained below. The Commission also checks the results of the ECAPM against the most straightforward form of DCF, finding the other DCF variants in this proceeding to be flawed. The Commission accords little weight to the remaining analyses, finding them at best cumulative and usually flawed in ways that the Commission's primary methods are not. The Commission discusses each of these models in turn, before presenting its calculation. The Commission also rejects an ex post small-size risk premium to its ROE calculation, because it is not supported by evidence in the record, and the Commission's most recent precedent presents an issue which the Joint Applicants have not answered.

The Capital Asset Pricing Model and the Discounted Cash Flow Methodologies

115. The Capital Asset Pricing Model ("CAPM") has several attributes which favor its use. Most importantly, it is a theoretically superior model because it attempts to anchor the firm's ROE to market-wide trends, in a way that rival methodologies do not. The Commission acknowledges that investors in utilities may choose to buy some other equity, not just other utility stocks. It is, therefore, important to sample the wider market, while considering also the less risky nature of an investment which is subject to the protections of economic regulation. This is consistent with CAPM's conceptual basis, as can be seen through its algebraic expression, $k = Rf + \beta$(Market Risk Premium ("MRP")), where the ROE is calculated by the addition of a the risk-free rate to the premium commanded by the equity market, as adjusted by

β, which in this instance is the co-variance of a proxy group of gas utilities to the wider equity market. Both Hill and Scheig present CAPM results, and Scheig also presents various ECAPM results. Test. Scheig 19-26, Ex. GES-2 2-3, 5-6; Test. Hill 33-36, Ex. SGH-8.

116. Other methods lack a basis tied to the wider equity market, and instead focus more closely on how analysts believe a proxy group of regulated firms will perform. The conventional DCF method, for example, is expressed algebraically as k = D/P + g, where the ROE equals the anticipated dividend yield added to analysts' expectations of the firm's growth. The reliance exclusively on the proxies' results will tend toward self-reference, as other utility commissions establish authorized returns and set expectations for capital investment, which drive the proxies' earnings and growth, and which in turn produce the ROE result which an application of the DCF method would suggest the Commission to adopt. This positive feedback loop makes the methodology unreliable, and this circularity is further aggravated by the limited size of the proxy group. In this proceeding, Scheig's proxy group is comprised of 11 firms. Test. Scheig 6, 37, Ex. GES-2 2-3, 5-10. Hill excludes four firms, citing various irregularities, and is left with only seven firms. Test. Hill 23. Either way, it is a small sample of companies from among the many hundreds that are included in the wider public equity market.

117. CAPM necessarily relies on the proxy group, but only for one of its variables, the calculation of β (beta). In this proceeding, β shows little variance between Bloomberg and Value Line, which calculate the variable for each of the proxy companies, and the value is clustered between X and Y for the highest and lowest β proxies. Test. Scheig, Ex. GES-2 2-3. Hill arrives at essentially the same value for β. Test. Hill, Ex. SGH-8. Meanwhile, the multitude of discretionary inputs in the DCF model can cause the results to vary, sometimes considerably. The Commission, were it to rely on DCF substantially, would want to very carefully parse all inputs (e.g., analysts' projections) for the limited number of proxies before accepting their validity. Such an initiative, however, would risk turning the ROE exercise into a yet more subjective undertaking. The Commission, again, is attempting to avoid a flyspeck analysis, and favors one that exists with reference to the wider market, while considering comparable risk.

118. As β shows little variability, then, the main question in relation to β is whether it has fidelity to the actual results of the firms whose return requirements are being projected. Scheig cites to a widely used textbook by Roger Morin which incorporates study results showing that the realized returns of low-β firms exceeded CAPM projections, even with the use of

adjusted betas. Test. Scheig 23, n.19. On this point, the Commission agrees with Scheig that CAPM's empirical results understate the actual returns of low-β equities. In order to remediate this issue, Scheig again borrows from Morin's textbook, which incorporates this α (alpha) effect in simplified form, as a factor x, as a modification to the basic CAPM equation, such that k = Rf + x(MRP) + (1-x) β (MRP). *Id.* In essence, x represents an adjustment which will cause the results of CAPM to regress to the MRP in proportion to the attributed value of x. Its justification, Scheig suggests, is to moderate CAPM's results so to better align to the empirical observations that CAPM forecasts understate the eventual returns of equities which have a relatively smaller value for β; thus, this methodology is known as the ECAPM. *Id.* at 21-23. Hill asserts that the use of the ECAPM with the use of adjusted betas is inappropriate as both serve to lower the slope of the Capital Market Line. Test. Hill 65. However, the Commission is persuaded by Morin's representation that "[t]he ECAPM and the use of adjusted betas comprise two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks." *See* Morin, Roger A. "Chapter 6: Alternative Asset Pricing Models." New Regulatory Finance Vienna: Public Utilities Reports, Inc. 2006.191. The Commission agrees with Scheig that the issue should be remedied by adopting the ECAPM, including his x factor of 0.25, which is intended to approximate the α effect identified by the academic literature reviewed in Morin's textbook.

119. In future proceedings, the Commission strongly suggests those who wish to justify a particular α within ECAPM, or who wish to use a conventional CAPM because the adjusted β already embeds α, present those arguments robustly. Additionally, much of the academic literature appears to refer to CAPM's general empirical results, and not to whether it is an accurate predictor of economically regulated firms' β. Hill does not raise this point, and the Commission invites testimony on it in future proceedings.

120. Aside from β, the main input to CAPM is the MRP. The MRP is by definition a function of the return of the wider equity market over the risk-free rate. Both the Joint Applicants and the MCC agree that the risk-free rate should be represented by long-term U.S. Treasury bonds ("T-bills"), although Hill suggests a short-term T-bill is truly the greater measure of a risk-free asset because it avoids the question of opportunity cost implicated by a longer-maturity asset, which has the effect of tying up an investor's capital over decades. Test. Hill 34. The Commission accepts that a long-term T-bill is most appropriate, especially in circumstances

where the MRP is being calculated on the basis of results perceived over a longer term; as seen below, the Commission adopts one such variant of CAPM. The Commission adopts Scheig's expected 3.19%, which represents the projection of the return of long-term T-bills in an environment where interest rates seem to be rising, after many years of stagnation at the hands of the Federal Reserve. Rebut. Test. Scheig, Ex. GES-1R 5-6, 9-10.

121. Having reasoned a risk-free rate, the value of MRP is the return of the market net of it. How the return of the wider market should be measured is thus a primary consideration of CAPM, equal to or greater than the importance of β. Within both Hill's CAPM and Scheig's CAPM and ECAPM analyses, the MRP is derived with respect to the performance of the market between 1926 and 2016, and the risk-free rate. Test. Hill 34. Scheig notes a tension in this approach, given that ROE determinations are intended to be forward-looking projects for rates not yet in effect, and thus should be grounded in the present-day market, not the past. He thus prepares modified ECAPM analyses which are grounded on the recent performance and anticipated growth of various firms from among the S&P 500.

122. Consistent with the Commission's reasoning above, it is important to calculate an ROE that represents the opportunity of investors to trade off in the wider equity market. In this vein, it is reasonable that the ROE determination should incorporate equity conditions looking forward over the next several years, when the public equity market looks volatile but somewhat robust. However, the Commission is conscious of Hill's criticism that an MRP in excess of 9%, as most of Scheig's Modified ECAPM analyses suggest, is exorbitant. Test. Hill 56-62. When asked directly, Scheig could cite to no literature that supports such an MRP. DR MCC-049 (Dec. 12, 2017). Indeed, Duff and Phelps, the source of the historic MRP data, suggests a going-forward premium of 7.0%. Test. Hill 34.

123. The Commission does two things to mitigate this concern. First, the Commission, will accept only one of Scheig's four variants of the Modified ECAPM, which limits the number S&P 500 companies sampled to only those which pay dividends and which have an analyst-projected growth rates and total equity returns between 5 and 20%. Test. Scheig 29. This analysis still includes a large sample of companies. [*Id.* at Ex. GES-2, Sched C.4. The Commission also reasons that the limitation to dividend-paying companies is important because investors, while they may trade-off utilities against the wider market, likely seek some dividend payout, and not just capital appreciation, as an attribute of their equity investment. See Test. Scheig 26. Hill

criticizes Scheig's decision to collar the sample to 5 to 20%. Test. Hill 62. He calculates that if one were to limit this sample to dividend-paying companies with between 0 and 10% results, which he expects is a more reasonable proxy for the economically regulated firm in question, that the result would be 9.88%, although he does not present work papers associated with this analysis in his testimony. *Id.*

124. The Commission believes that the 5 to 20% range is more reasonable than the 0 to 10% range. It may be reasonable in future proceedings to adopt a different range, perhaps 0 to 20%. Although the Commission does not engage in that calculation here, and upon review of the very large sample group in question, the Commission is satisfied that anomalous results are largely mitigated by this upper collar. Accordingly, the Commission adopts Scheig's Modified ECAPM MRP of 9.19%. Test. Scheig, Ex. GES-1R, Schedule C.20 at 65]. Additionally, while the Commission makes adjustments to the group of companies for the basis of measuring MRP, the main element of the CAPM or ECAPM equation which will internalize the risk adjustment for the firm in question should be β. The Commission also modifies Scheig's proxy group of companies for calculating β. WGL holdings recently merged with another holding company. Therefore, the Commission adopts a .72 which represents the arithmetic average of the proxy group used in Exhibit GES-1R, excluding WGL. *Id.*

125. Second, the Commission will moderate the effects of this application of a Modified ECAPM by equally weighting it with a more conventional analysis that relies on the historical MRP. The Commission does this in recognition of Hill's valid concerns about a potentially anomalous MRP. *Supra* ¶¶ 120-122. Local distribution companies such as the Joint Applicants and equities like them serve the rest of the economy, and their growth is likely slower than the broader economy at times of rapid growth but also more persistent than other parts of an economy when other equities slump. Investors also presumptively understand that certain firms boom-and-bust while others ride-through, and it is reasonable to consider this phenomenon in making an ROE determination. The long-duration average growth of the United States economy captures the basis on which to measure the return demands of more stable firms such as regulated gas utilities.

126. As explained above, the Commission views either of the variants of CAPM on which it relies to be superior to DCF. *Supra* ¶¶ 116-117. One additional problem of the Constant Growth DCF methodology is that it assumes that observations about the small proxy group's

near-term expected growth will endure as a constant. This is a reason why both Scheig and Hill perform variants of the DCF model, with Scheig performing a Non-Constant Growth DCF analysis and Hill performing a Sustainable Growth model, which he uses as his primary indication of the cost of equity capital. Test. Scheig 29; Test. Hill 42. Scheig's Non-Constant Growth DCF analysis relies on investors' short-term earnings projections to an extent, but relies more heavily on future stock price projections. Hill's Sustainable Growth DCF analysis substitutes sole reliance on short-term earnings expectations for an approach considering multiple factors such as dividend, earnings, and book value growth projections. The idea being that by considering various factors other than earnings estimates, one can arrive at a growth estimate that is more "sustainable." This is conceptually appealing as the Commission finds merit in Hill's representations that sell-side analysts' earnings projections are likely to offer "rosy" expectations for the stocks they follow. Test. Hill 28. However, the manner in which the witness employed this approach made its deficiencies clear.

127. As explained in Appendix B, this model is intended to derive a growth rate as an arithmetic function of internal growth (br) and external growth (sv), where g=br + vs. Test. Hill, Appendix B at 1-3. Implicit in this formula is the assumption that both "br" and "sv" result in growth. As seen in the appendix, "br" is calculated as the return on equity times the retention ratio and "sv" is the funds raised from the sale of stock as a fraction of existing equity times the fraction of new common stock sold that accrues to current shareholders. *Id.*. Hill did not employ this formula as designed. His Sustainable Growth DCF results did not use a "br" value arithmetically calculated as described in Appendix B. DR PSC-129(c) (Mar. 23, 2018) Rather, as noted above, the witness considered multiple factors and used subjective judgment to arrive at a value for "br." *Id.*; Test. Hill, Appendix C, Ex. SGH-4 at 1. Moreover, in the process of discovery, it became apparent that the manner in which the witness employed this model did not result in any growth from his "sv" input. When asked to amend his "sv" calculation to be theoretically consistent with the concept of growth and consistent with the narrative found in Appendix B, the witness concluded that his DCF results would "result in an overstatement of the cost of equity (the growth rate would be too high)," and amended the manner in which he derived "br." DR PSC-129(c). Since the witness adjusted his approach with regards to his "br" input when asked to only change his approach to the "sv" input, the degree to which subjectivity influenced the results of his Sustainable Growth DCF analysis is highlighted.

128. The Commission does not consider Hill's Sustainable Growth DCF results in this proceeding. Scheig's Non-Constant Growth DCF analysis is similarly unreliable as it places an inordinate amount of reliance on longer-term projections of the proxy companies' stock prices at intervals several years into the future. The Commission accepts Hill's criticism of this method, which replaces a shorter-term variable known with greater certainty for a much more speculative estimate of stock price, which is not only unpredictable but also may not be a sound indicator of growth. Test. Hill 66-70.

129. Ideally, DCF would incorporate a longer-term perspective on growth, but both variants presented are unreliable. Therefore, the Commission is left with the basic, constant-growth or mechanical DCF method. The Commission finds that when aberrant companies, those with DCF-indicated ROE's of >20% or <5%, are excluded from proxy group(s), the restated DCF, using the latest data available from Scheig's rebuttal testimony, results in an average indicated return on equity of the proxy companies of 9.40%. Rebut. Test. Scheig, Ex. GES-1R at 71. The Commission uses this as a check against the CAPM results, because while it suffers from the infirmities of self-reference, it can inform the Commission about whether its measures using CAPM are too radical a departure from the expectations of the regulated gas-utility sector investors. The Commission calculates the allowed ROE as follows:

(1) calculates the arithmetic mean of the three DCF results,
(2) calculates the arithmetic mean of the two ECAPM analyses,
(3) takes the results of the Commissions Modified ECAPM using a MRP of 9.19% and a β of .72 *Supra* ¶ 124.
(4) calculates both the arithmetic and geometric means of the resulting figures from steps 1-3.

Accordingly, the Commission adopts 9.2% as the cost of equity to be used in calculating the revenue requirements of the Joint Applicants, as represented in Table 8.

Table 8

DCF Analyses-Scheig (Rebuttal)		Estimated ROE
Sched D.1	Value Line	10.38%
Sched D.2	Zacks	9.02%
Sched D.3	Bloomberg	8.82%
		9.40%
ECAPM Analyses-Scheig (Rebuttal)		Estimated ROE
Sched B.8- forecasted rf rate	Value Line β	7.91%

Sched B.9-forecasted rf rate	Bloomberg β	7.77%
		7.84%
Modified ECAPM Analyses-Scheig (Rebuttal)		Estimated ROE
Sched C.20- forecasted rf rate	Value Line β	10.45%
		10.45%
GEOMETRIC AVERAGE ROE		**9.17%**
ARITHMETIC AVERAGE ROE		**9.23%**

Risk Premium - Authorized Gas Returns

130. Scheig also performed a risk premium study which compares gas utility authorized ROEs to long-term utility debt rates. Test. Scheig 30.

131. Because the risk premia used in deriving regression equation rely on historic Commission-approved natural gas ROEs, this methodology is perhaps the most susceptible to self-referential outcomes of all the methods employed by the witnesses. Widespread adoption of such a method would inherently result in a circular, positive feedback loop with no grounding in the wider equity market. *Supra* ¶ 116. The Commission is persuaded by Hill's argument that differences between allowed returns and bond yields are not necessarily reliable indicators of investor-required risk premiums, given the fact that the market prices of gas utilities over the time period studied by Scheig have been substantially above book value. Test. Hill 71-72. Therefore, the results of these analyses do not receive consideration by the Commission. It is noted that if the historical market values of natural gas utility stocks were equal to the historic book values, this method could potentially be considered a valid indicator of actual investor required returns for that historic period. However, there is no indication that current (or forecasted) market conditions mirror the conditions faced by investors during the historic time periods. Therefore, it is not reasonable to assume that current (or forecasted) market-to-book ratios would resemble the historic market-to-book ratios. This method is not grounded in the current, wider equity market(s) and is rejected.

Expected Earnings

132. Expected earnings methodology, more commonly referred to as a Comparable Earnings analysis, relies on analysts' earnings and book value projections. Test. Hill 74. The ROE is calculated as a function of forecasted earnings divided by forecasted book values. Scheig

argues that this methodology avoids the complexities of other methods and is consistent with the fair rate of return concepts set forth in Hope and Bluefield. Test. Scheig 40. Moreover, he states that the resulting ROE is an indicator of investor expectations for current and future equity returns. *Id.* The Commission is not persuaded by this statement. The average market-to-book ratio of Scheig's proxy group companies is 2.26. Test. Scheig, Ex. GES-2 at 77. It is reasonable to assume that investors' expectations are lower than what the results of these analyses would indicate as the earnings-to-(market) price ratios of the proxy group companies more accurately depict actual returns earned by investors. Moreover, because this method solely relies on proxy group projections, it is not grounded in the wider equity market(s) and suffers from the same self-referencing, circular, positive feedback loop shortcomings as the other methods which rely on the proxy group companies. *Supra* ¶ 116. Therefore, the Commission does not consider the results of these analyses.

Modified Earnings - Price Ratio

133. Hill's Modified Earnings-to-Price Ratio ("MEPR") methodology calculates an ROE as the midpoint(s) of the proxy group's average earnings-to-price ratio and its average current and projected ROEs. Test. Hill 36-37. Due to its reliance on the proxy group companies, this method suffers from the same self-referencing, circular, positive feedback loop shortcomings as the other methods which rely on the proxy group companies. *Supra* ¶ 116. Moreover, the Commission finds merit in Scheig's representation that this is not a model used by actual market participants. Rebut. Test. Scheig 11. If this were a widely-used model, Hill likely would have been able to cite specific examples of its use by market participants employing the model in the exact same manner as he proposes. Rather, Hill cites to an arithmetic equation that merely illustrates the stochastic relationship between expected returns and earnings-to-price ratios. Test. Hill 38. Therefore, the Commission does not consider the results of these analyses.

Market-to-Book Ratio

134. Hill's Market-to-Book Ratio analysis is essentially an algebraic derivative of his Sustainable Growth DCF model. Test. Hill 40. He uses the same proxy group and growth ("g") assumptions as he did in his Sustainable Growth DCF analysis, and thus, this model suffers from the same degree of subjectivity as his DCF results. Moreover, because of the widespread use of proxy groups in rate cases, the results of DCF analyses tend provide circular ROE estimates lacking any real foundation in the wider equity markets. Therefore, these results tend to reflect

commission approved ROEs as opposed to actual investor required returns. For these reasons, the Commission does not consider the results of these analyses.

Small-Size Adjustment

135. Most of the substance of the debate on an appropriate ROE turns on the formulaic calculations using market data that are discussed above. However, in terms of impacts on the allowed ROE, the Joint Applicants' advocacy to impose a "small size risk premium" ("SSRP") is no less important. An SSRP is an ex post adjustment to the ROE result calculated above; the Commission therefore considers it separately, and upon consideration of the evidentiary record, rejects it.

136. Scheig advises that a size risk adjustment is appropriate because EWM & CBGC are significantly smaller than the proxy group he relied upon for his cost of capital analyses and argues the companies are not public and, therefore, have illiquid equity interests. Test. Scheig 32. Therefore, an adjustment must be made to that ROE to account for the Joint Applicant's small size in arriving at a final ROE estimate. *Id.* He bases his suggested SSRP adjustment on Duff and Phelps' size premia studies which examine the Stock Size Premiums of the entire universe of NYSE-, AMEX-, and NASDAQ-listed securities from 1926 to the present. *Id.* at 32-34. In the studies, the risk premium required due to each firm's size is estimated by dividing the universe of securities into portfolios by capitalization and measuring the premium required beyond the risk-free rate and the security's equity risk premium estimate (beta). *Id.* at 33. The study concludes that the required SSRP increases inversely to firm size and is in addition to the required systematic (i.e., market) risk. *Id.* According to Scheig, based on this study, EWM and CBGC would fall into the 10th decile, which equates to an SSRP of 5.59%. *Id.* at 34. However, Duff & Phelps only considered unregulated companies in their survey, therefore, the regulated nature of EWM & CBGC offsets some of the risk factors reflected in the SSRP indicated above *Id.* at 33. He used data provided by Duff & Phelps' studies to calculate a weighted average SSRP for the proxy group of 1.13%. *Id.* at 36. Taking these factors into consideration, and relying on his professional experience and judgment, Scheig selected 1.25% as a minimum SSRP for EWM & CBGC. *Id.* at 36; DR PSC-034 (Feb. 8, 2018); Rebut. Test. Scheig 14-15.

137. Hill argues the market-based cost of capital for a small gas distribution utility operations such as EWM and CBGC should not be adjusted upward due to its relative size for what appears to be a long-term historical return difference between large and small firms:

- Although there is substantial evidence that a size premium does not currently exist, even if a size premium does appear in the long-term historical record for unregulated stocks, utility-specific research shows that it does not apply to utilities;
- The evidence on which the "size effect" logic is based (the long-term historical return difference between large and small unregulated companies in the broad stock market) suffers from what is termed "survivor bias"; and
- The Duff & Phelps studies relied on by Scheig are based on broad market indices such as the New York Stock Exchange (NYSE) Index. In order for a small company to be listed on a national stock index like the NYSE, it has to be extraordinarily successful.

Test. Hill 49-51. Therefore, the returns of the small companies being measured are considerably higher than the returns of the many small firms that: a) are not successful enough to be listed, or b) may have failed altogether. *Id.* at 51.

138. The Commission is not persuaded by this argument by Hill as it does not appear to be translatable to the regulated utility sector. The paradigm of utility regulation requires commissions to authorize ROEs commensurate with returns on alternative investments with similar risk. *See* Hope and Bluefield. If an investor were to supply equity to these unsuccessful (or failed) companies referred to by Hill, they would likely require higher returns due to the heightened unsystematic risk reflected in the risk profiles of those companies.

139. Hill argues the "size effect" is also called the "January effect" because virtually all (95%) of the small stock effect occurs only in the month of January. *Id.* at 54. The Commission is not persuaded by this argument as returns are "annualized." Therefore, it is unreasonable to parcel-out the month of January as it is inherently included in any calculation of annual returns.

140. The Commission previously opined on how a regulated company's size should affect its allowed return. This decision, made seven years ago, was not a model of clarity, appearing to hold that an adjustment for size was appropriate but resisting the nomenclature associated with it. First, the Commission surmised that it was "reasonable" to authorize a higher return for EWM than for a larger utility the Commission regulates, NorthWestern Energy, because "small utilities have a higher financial risk profile than large utilities." Docket D2010.9.90, Order 7132d ¶ 96-97 (Dec. 30, 2011). The MCC sought reconsideration of that finding, and the Commission went on to explain:

> The Commission did not authorize a small size risk premium in its calculation for rate of return, but did recognize that a smaller company is more sensitive to like

> dollar revenue streams than a larger company. The commission has not recently awarded small and microcap companies a significant basis point premium on their ROE compared to larger cap companies…The Commission did not establish a small size risk premium as EWM requested in this docket but only discussed how EWM is smaller than NorthWestern Energy and Montana-Dakota Utilities and should be awarded an ROE that is slightly higher.

Order 7132d ¶ 13.

141. More recently, the Commission rejected a small-size risk premium, more clearly articulating its reasoning:

> MDU contended that its small size and relatively undiversified service territory makes it more risky and therefore it should command a higher reward. However, many of the proxy companies are an amalgamation of small utilities. The proxy group's dividend and growth forecasts in the DCF results may incorporate all or some portion of those risks. The Commission finds that adding an ex post risk premium adjustment to the DCF results would result in double-counting those risks.

Order 7433f, Docket D2015.6.51, ¶ 22, (Mar. 25, 2016).

142. The Commission will continue to reject an SSRP and in doing so will articulate a number of reasons. First and foremost, the Commission's foundational concern expressed in Order 7433f has gone unanswered in this proceeding. Most of the proxy companies in Scheig's and Hill's analysis are made up of numerous operating companies. Hr'g Tr. 232:4-5. As Scheig noted at the hearing in this matter, "[m]ost of them have rate cases in each specific jurisdiction as opposed to one large one for the holding company." *Id.* at 232:11-13. Scheig conceded that he did not study whether the larger holding companies of his proxy group already contained an implied premium due to their composition of multiple, small operating companies. *Id.* at 233:15-21. Since the Joint Applicants do not answer the specific concern that led the Commission to reject the SSRP most recently, the Commission finds they have not met the burden of proof to substantiate this substantial ex post adjustment.

143. There are additional reasons on the merits of the issue which lead the Commission also to reject the SSRP. First, if a firm is more financially risky than its peers because of its size, such a trait should be reflected in its relative volatility to the peers' performance and to the market's as a whole. Yet the primary empirical measurement of the volatility of return, β, does not bear this out. *Supra* ¶ 117. The smallest members of the proxy group, Chesapeake Utilities Corporation and Northwest Natural Gas Company, have β values which are below the mean; in

other words, they are less volatile in their market performance despite being less well capitalized than their larger peer regulated gas companies. Rebut. Test. Scheig 13 (showing the relative market capitalization of proxy group members), Ex. GES-1R at 50 (showing Beta). Meanwhile, the highest-β member of the proxy group, UGI Corporation, is the third-largest of its 11 members. *Id.* The β values suggest no obvious correlation between size and risk.

144. Scheig did not study the endogenous factors that would inform the risk of the Joint Applicants in particular. Test. Scheig 18. Instead, his is an analysis which adopts ipso facto the proposition that smaller firms will require a higher return. Clearly there is empirical support that the historical market returns for small public companies are larger on average than those of larger public companies. *Id.* at 33. However, sufficient evidence has not been presented supporting the proposition that this information is translatable to the regulated utility sector.

145. The Commission, however, primarily agrees with Hill in his criticism of Scheig's premise, that the risk premia associated with the wider public equity market can be translated seamlessly to the experience of regulated utilities. Test. Hill 50-51. Both large and small utilities are insulated from the type of risk which may present for smaller firms, because they are economically regulated by public service commissions. As noted above, the only empirical evidence of size-based risk suggests no correlation. *Supra* ¶ 117. Moreover, the Commission reasons that risk has more to do with the peculiarities of the service territory and business model of a regulated utility than its size. Large utilities may serve a more sprawling service territory that exposes them to greater risk of natural disasters, like wildfires, or may serve more dense urban communities where infrastructure may be more aged and dangerous, or where gas line replacements are more difficult to undertake. Indeed, the riskiest utilities may be those which have the largest balance sheets such that in the first instance they may make big bets that fail.

146. Even were the Commission inclined to accept Scheig's advice on conceptual grounds, his calculation of his proposed SSRP leaves much to be desired. The recorded SSRP for the smallest decile of public companies is 5.59%. Test. Scheig, Ex. GES-2 at 77. He reasons that the holding companies comprising the proxy group already include an implied risk premium based on their fitting within particular deciles, which averages to 1.13%. Therefore, Scheig calculates that the "additional required SSRP" for the Joint Applicants would be 4.46%. *Id.* Then, however, he scales this down to 1.25%. *Id.* He reasons, generically, that "some of the risk factors reflected in Duff and Phelps' study above are offset by the regulated nature of their

business," but nowhere does Scheig calculate or show any detail of how, from a basis of 4.46%, he has arrived at a proposal of 1.25%. Test. Scheig 33. Given that the cost of capital witnesses in this proceeding spend cumulatively hundreds of pages of testimony and discovery debating over methodologies that result in adjustments of hundredths of percentage points, the Commission is naturally very hesitant to accept a suspiciously round number whose exact provenance cannot even be identified.

147. For all these reasons, the Commission rejects the SSRP. The Joint Applicants have not met their burden of proof. In the future, should a utility applicant seek an SSRP, they must demonstrate through clear evidence several things. First, they must demonstrate that size serves as an adequate proxy for utility-specific, unsystematic risk. Second, show that the risk premia effect that appears for small public companies relative to larger public companies is actually translatable to the regulated utility sector; the primary evidence of this should be β of proxy companies, or other direct evidence which suggests a size-based return differential associated with regulated utilities. Third, and relatedly, such an applicant must clearly answer through comprehensive analysis the problem identified in Order 7433f. *Supra* ¶¶ 141-142. Such analysis would include breaking down a public holding company into its various operating companies, and contrasting their performance and returns, which presumably would be reporting in the holding companies' financials, with market-wide risk premia.

148. The Commission also rejects Scheig's proposition that consideration should be given to the Joint Applicants' private, illiquid, equity interests. *Supra* ¶ 136. A long-standing Commission practice has been to evaluate utility ROEs on a stand-alone basis. If the Commission were to consider the upstream ownership structure and equity provided therefrom, it would also be necessary to consider other factors beyond the scope of this proceeding.

Cost Allocation and Rate Design

Cost Allocation

149. In its last rate case, Energy West relied on minimum system theory to classify investment in distribution mains 70% customer-related and 30% demand-related. Docket D2010.9.90, Order 7132c, ¶ 103 (Nov. 18, 2011). The Commission rejected the classification of mains to customer on the basis that the utility's asserted cost causality was not convincing, and that the classification appeared to violate the principle of vertical equity through assignment of

equal cost responsibility to very small and very large customers. *Id.*, ¶ 106. Additionally, the Commission faulted the utility for presenting a study for the allocation of system costs which could not be reconciled to the physical reality of the utility in question. *Id.*, ¶ 108. Here, Mr. Loy's testimony does not suffer from the same infirmities. He has conducted a Minimum System Study that estimates the cost of "a minimum size system to hook up customers," in contrast to "the cost of the actual mains, sized to meet capacity requirements at times of maximum demand." Test. Loy 18. The import of such a study is that the incremental cost of larger-diameter mains can be considered to be a function of meeting demand, and thus properly allocated on that basis; meanwhile, the hypothesized cost of the minimally-sized system is a function of the number of customers connected to the utility. The results of Loy's study suggest classifying distribution mains, and their attendant costs, as 44% customer-related and 56% demand-related in the Energy West/Cut Bank service areas. *Id.*

150. Donkin does not specifically reply to the Joint Applicants' Minimum System Study, but does offer a hypothetical example that suggests the premise behind such a study is flawed. He posits that a small manufacturing plant with a peak demand of 20 Mcf requires the same investment in mains infrastructure as do 20 residential customers, each with a coincident peak of 1 Mcf, which, he suggests, demonstrates that "a gas utility's distribution lines are sized and installed to meet customer loads and not customer counts." Test. Donkin 27. The Commission believes Donkin's example incorrectly hypothesizes that the length of mains necessary to serve less and more dense sources of demand for natural gas is similar. A minimum system study that actually identifies the mileage of the system, as Loy's does, will correctly identify the attributes of length and width, and their attendant relation to customer count and demand, that tend to drive investment in mains.

151. Previously, the Commission was "not persuaded that it would be reasonable to classify a substantial portion of mains costs [to be] customer-related, as EWM proposed." Order 7132c, ¶ 106. Loy's classification is sufficiently demand-weighted to satisfy the Commission's concerns about vertical equity. For the reasons explained above, the Commission is now persuaded to accept Loy's Minimum System Study as a reasonable basis for allocating mains and their attendant costs.

152. Loy's direct testimony contains little discussion of another major category of rate base value: the service lines, meters, and regulator equipment. He cursorily suggests a complete

allocation of these items as 100% customer-related. Test. Loy 18. Upon close review of his work papers, the Commission finds that Loy allocates these costs largely on the basis of weighted-average meter costs rather than on customer numbers. This results in a weighting that generally distinguishes between the more expensive meters installed to serve larger general service and commercial tariff customers and standard residential meter technology. The Commission surmises that this allocation generally satisfies its criterion from Docket D2010.9.90 that costs should be allocated in part on the basis of capacity, since the cost of a meter is related to its capacity, but is frustrated that Loy has left much of this to the Commission's inference. Or. 7132c, ¶ 106.

153. Donkin cites to Commission precedent which favors his classification of this plant as 50% demand-related and 50% customer related. Test. Donkin 30-31 (citing to Order 7132c, ¶ 106). In rebuttal, Loy mounts a more substantial, less cursory argument, citing to a gas utilities' trade association manual in support of the proposition that "the closer the plant item (e.g., a meter and service lines) is located to a customer, the more that particular item is related to the specific requirements of that customer." Rebut. Test. Loy 9 (Apr. 9, 2018). He suggests that while costs of meters and services for individual customers may be greater because of that individual customer's demand, it does not follow that such incremental costs should be allocated to *system-wide* demand. *Id.* at 10.

154. The Commission finds that neither witness has particularly well explained their recommendations on this point. On one hand, although Mr. Donkin has classified Accounts 380 (Services) and 381 (Meters) 50% demand-related and 50% customer-related, he classifies other significant categories associated with services and meters, such as Accounts 382 (Meter Installations), 383 (House Regulators), and 384 (House Regulator Installations), as 100% customer-related. Test. Donkin, Excel support file "GLD-2 EWM COS," tab 'Totals Functional,' lines 18-24. Such a proposal appears self-contradicting. On the other hand, although Loy classifies all service and meter plant accounts 100% to customer, he allocates these costs to customer classes on the basis of weighted average meter costs by class. *Id.*; Excel support file "Dist COS WPs," tabs 'Meters' and 'Great Falls.' Because the cost of a meter is in large part driven by its capacity, this results in allocations of service and meter plant costs that are more demand-weighted than the meter and service plant allocations of Donkin, who allocates demand-related service and meter costs on the basis of non-coincident peak monthly volumes, and

customer-related costs on customer numbers. Test. Donkin 31, 38. Thus, Donkin allocates *more costs* of services and meters to the customer-heavy residential class than Loy does, because of the difference in their allocations of customer-related costs. *Compare* "GLD-2 EWM COS," tab 'COS-Total,' line 18, in the amount of $9.6 million, to "EWM COS," tab 'COS-Total,' line 18, $8.0 million. One cannot especially blame Donkin for the oversight, because Loy's work in this regard is not transparent.

155. All in all, the Commission agrees with Loy's observation, made in rebuttal, that "the per customer level of service and meter plant in the EWM COSS are close to the MCC's level [of] per customer costs." Rebut. Test. Loy 10. The Commission, therefore, will go no further than that in trying to make sense of the confusing, rival studies in this regard, and especially in the absence of a clearly explained methodology in the first instance; it will continue its prior precedent, while noting that, like in the example of the allocation of mains, the Commission remains open to being persuaded otherwise.

156. The Commission's complete and final resolution of the allocated cost of service studies is apparently not necessary in any case, because Donkin and Loy only loosely follow their recommendations in allocating costs to classes. For Energy West, both witnesses appear to concede a rigorous adherence to their studies would mean substantial increases to the residential class, which they both propose to moderate, and with respect to Cut Bank Gas Company, it is just the opposite, which again they propose to moderate. Test. Loy 25-30; Test. Donkin 35, 40-42. The Commission, while offering the general guidance it does above, does not find it necessary to tabulate cost of service results in a precise form. Rather, the Commission sets forth the following allocation, which coheres to the commentary above:

Table 9

Final Cost Allocation of CBGC Revenues

Customer Classes	Current[1]	Ordered	Pct Chg
Residential	$ 487,393	$ 556,152	14.11%
General Service	211,192	270,671	28.16%
Total Cost of Service	$ 698,585	$ 826,823	18.36%

1: Source - Henthorne Dir. Test. Exh. JDH-CBG-6, Statement H

Rate Design

157. Rates must be designed to recover the costs that have been allocated to particular customer classes. Since some of those costs were allocated in the first instance on the basis of customer counts, the Commission finds it reasonable that there should be a corresponding fixed charge billed to each customer in a class regardless of gas consumption. Thus, the percentage of residential class revenues classified to customer should equal the percentage of revenues recovered through a fixed charge, with projected revenues scaled to authorized revenues in this case. Accepting either Mr. Donkin's or Mr. Loy's cost-allocation study for this purpose, the customer charge for EWM would be either $6.25 or $12.75, respectively, which is the function of allocating 42% or 86% of distribution revenues to this charge. Mr. Loy's and Mr. Donkin's bookends happen to be wide apart, due to the utility's predilection to classify costs as customer-related (and thus increase the fixed charge, which would be charged year-round and not be subject to the vicissitudes of weather-related gas demand), and to the countervailing tendency of the consumer advocate to classify costs as commodity- or demand-related (which has the effect of minimizing the rate impact on residential customers). The current residential customer charge is $7.25 for EWM, $13.00 for CBGC, and $7.25 for the West Yellowstone utility. The Commission maintains each of these charges at their current levels, for two reasons.

158. First, the approval of GIRC, will mean that for EWM and CBGC an additional monthly surcharge calculated on a per-customer basis will be added to monthly bills beginning in September 2020. If GIRC operates as expected, this surcharge will grow through 2024, until it is rolled into rates or lapses in 2025. Maintaining the customer charge at current levels allows for headroom so that the rate design of GIRC can be simplified and billed as a customer charge. The following table illustrates the expected rate impacts on customers regarding cost recovery of GIRC investment, with cost allocation similar to the allocation of the general revenue requirement.

Table 10

Expected Standard and GIRC-Related Monthly Customer Charges

Standard Monthly Customer Charge

Class	2018	2019	2020	2021	2022	2023
GF Res	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 7.25
GF SGS	18.00	20.00	20.00	20.00	20.00	20.00
GF LGS	110.00	110.00	110.00	110.00	110.00	110.00
GF EGS	850.00	850.00	850.00	850.00	850.00	850.00
GF Sand & Gravel	850.00	850.00	850.00	850.00	850.00	850.00
Pasta Montana	850.00	850.00	850.00	850.00	850.00	850.00
Benefis Hospitals	850.00	850.00	850.00	850.00	850.00	850.00

Per Customer Monthly GIRC Charge[1]

Class	2018	2019	2020	2021	2022	2023
GF Res	$ -	$ 0.12	$ 0.37	$ 0.62	$ 0.85	$ 1.08
GF SGS	-	0.26	0.78	1.29	1.78	2.26
GF LGS	-	1.46	4.34	7.21	9.97	12.62
GF EGS	-	10.55	31.43	52.28	72.34	91.55
GF Sand & Gravel	-	14.19	42.28	70.33	97.31	123.16
Pasta Montana	-	30.50	90.90	151.21	209.21	264.77
Benefis Hospitals	-	35.25	105.06	174.76	241.80	306.02

Standard Customer Charge plus GIRC

Class	2018	2019	2020	2021	2022	2023
GF Res	$ 7.25	$ 7.37	$ 7.62	$ 7.87	$ 8.10	$ 8.33
GF SGS	18.00	20.26	20.78	21.29	21.78	22.26
GF LGS	110.00	111.46	114.34	117.21	119.97	122.62
GF EGS	850.00	860.55	881.43	902.28	922.34	941.55
GF Sand & Gravel	850.00	864.19	892.28	920.33	947.31	973.16
Pasta Montana	850.00	880.50	940.90	1,001.21	1,059.21	1,114.77
Benefis Hospitals	850.00	885.25	955.06	1,024.76	1,091.80	1,156.02

1: Referencing the Direct Testimony of Charles Loy, Exhibit CEL-EWM-3, p. 1 of 2

159. Second, while the Commission desires to base its decision on the customer charge on a more analytical foundation, the Commission notes that the parties' witnesses themselves do not rigorously follow their cost allocation studies. Instead, they make largely subjective judgments about how the study-allocated costs should be moderated for the sake of actually allocating those costs to various customer classes. The lack of reliance on these studies to obtain

a result for a phase of ratemaking—cost allocation—which is the necessary predicate of rate design, raises the question of why the Commission would then rigorously adhere to these studies for the sake of calculating a precise customer charge. Accordingly, the Commission declines to do so. The existing customer charges are within the bookends of Donkin's and Loy's proposal if one accepts, as the Commission does, that the proportion of total costs allocated on the basis of customer determinants should be reflected in a customer charge. In the absence of a convincing proposition that the existing rates are unjust or unreasonable, the Commission finds that maintaining them is appropriate.

160. Since these utilities have a two-part bill for distribution cost recovery—the customer charge and the volume of gas used—the incremental revenue authorized by this Order will thus be allocated to the latter. In the absence of a demand charge, that costs allocated on the basis of demand are best approximated by a rate design that attributes these to the volumetric gas consumption component of the bill; the Commission reasons that most customers of these utilities are likely to use the most gas at the same time other customers are doing so, on very cold days.

CONCLUSIONS OF LAW

161. Energy West Montana furnishes gas service for consumers in the State of Montana, and is a "public utility" under regulatory jurisdiction of the Montana Public Service Commission. Mont. Code Ann. § 69-3-101.

162. The Montana Public Service Commission properly exercises jurisdiction over Energy West Montana's rates and operations. Mont. Code Ann. § 69-3-102, and Mont. Code Ann. Title 69, Ch. 3, Pt. 3.

163. The Montana Public Service Commission has provided adequate public notice of all proceedings, and an opportunity to be heard to all interested parties in this Docket. Mont. Code Ann. §§ 69-3-303, 69-3-104, and Mont. Code Ann. Title 2, Ch. 4.

164. The Montana Public Service Commission may prescribe classifications of the service of all public utilities. Each public utility is required to conform its schedule of rates, tolls, and charges to such classifications. Mont. Code Ann. § 69-3-306.

165. The Montana Public Service Commission may, after hearing and investigation, fix and order substituted rates, tolls, charges, or schedules as are just and reasonable if the rates are found to be unjust, unreasonable, or unjustly discriminatory or to be preferential or otherwise in

violation of the provisions of this chapter. Mont. Code Ann. § 69-3-330 (1).

166. The Montana Public Service Commission may, in its discretion, investigate and ascertain the value of the property of each public utility actually used and useful for the convenience of the public. The Commission is not bound to accept or use any particular value in determining rates. However, if any value is used, the value may not exceed the original cost of the property, except that the commission may include all or some of an acquisition adjustment for certain property purchased by a public utility in the purchasing utility's rate base if the transfer of the property to the purchasing utility is in the public interest. In making the investigation, the Commission may avail itself of all information contained in the assessment rolls of various counties or in the public records of the various branches of the state government or of any other information obtainable, and the Commission may at any time on its own initiative make a revaluation of the property. Mont. Code Ann. § 69-3-109.

167. Montana Public Service Commission is given the power to investigate and ascertain the value of the property of every public utility actually used and useful for the convenience of the public; under Mont. Code Ann. § 69-3-109, the Montana Public Service Commission is obligated to eliminate from rate base all utility costs in excess of original cost. *In re Montana Power Co.,* 180 Mont. 385, 590 P.2d 1140, 1979 Mont. LEXIS 713.

168. The rate levels approved herein are just, reasonable, and not unjustly discriminatory. Mont. Code Ann. §§ 69-3-330 and 69-3-201.

ORDER

169. For EWM, the Commission approves a total revenue requirement of $24,226,558 which results in an increase of previously approved revenue requirement of $479,461. This is based on a capital structure of 33.91% Long-Term Debt, 15.12% Short-Term Debt and 50.97% Equity. The Commission approves a 9.20% Return on Equity and a 6.91% overall return. For CBGC, the Commission approves a total revenue requirement of $1,416,130 or an increase of $128,238. This is based on a capital structure of 55.0% Equity and 45.0% Long-Term Debt. The Commission approves a 9.20% Return on Equity and a 7.45% overall return.

170. EWM is permitted to collect the PSC/MCC taxes on a per CCF basis through a separate rate component and is required to file compliance tariffs, accordingly. *Supra* ¶ 67.

171. EWM must file compliance tariffs implementing the approved rates and rate design within 30 days of the service date of this order.

172. All Findings of Fact and Conclusions of Law that can be properly considered an Order and that should be considered as such to preserve the integrity of this Order are incorporated herein as an Order.

173. These rates will be effective for services rendered on and after October 1, 2018.

DONE IN OPEN SESSION at Helena, Montana, on the 30th day of July, 2018, with Commissioner Lake dissenting as to the ROE and denial of SSRP; Commissioner Koopman dissenting as to the GIRC; Commissioners Koopman and O'Donnell dissenting as to the application of TCJA benefits; and Vice Chairman Kavulla dissenting as to keeping the monthly service charge at current rates.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

BRAD JOHNSON, Chairman

TRAVIS KAVULLA, Vice Chairman

ROGER KOOPMAN, Commissioner

BOB LAKE, Commissioner

TONY O'DONNELL, Commissioner

ATTEST:

Rhonda J. Simmons
Commission Secretary

Seal

ATTACHMENT A

PUBLIC SERVICE COMMISSION OF MONTANA

Energy West Montana, Inc. Tariff No. 05, Schedule GI, Sheet 01, Release 01

GAS INFRASTRUCTURE RELIABILITY CLAUSE

GENERAL DESCRIPTION

Purpose
To provide the Utility with the resources to accelerate the replacement of aging infrastructure as identified in Energy West's general rate case filed in D2017.9.80. To accomplish these tasks, the utility is permitted to recover the costs to replace Eligible Property, as defined below, when such Eligible Property is placed into service and recorded in the individual accounts, as referenced below.

To the extent that capital investment (as measured by original cost clearings to plant less GIRC related plant clearings) in a calendar year meets or exceeds the Utility's current year annual depreciation (excluding GIRC related depreciation), all GIRC Eligible Property costs from that calendar year will be included in the recovery determination. To the extent that capital investment falls short of annual depreciation, for purposes of determining revenue recovery, the investment in Eligible Property will be reduced by the shortfall for that calendar year to determine the quantity of GIRC-Eligible Property.

All costs of Eligible Property are subject to a review for whether its costs should be permanently included in the utility's rates when Energy West next files a general rate cost. The inclusion of such costs in a rate charged under this tariff shall not be evidence that the property is used and useful, or that associated expenses were prudently incurred.

The costs of extending facilities to serve new customers are not recoverable through the GIRC.

Eligible Property
Eligible Property Identified Through DIMP

- Approximately 42 miles of pre-1984 Aldyl-A pipe
- Mechanical couplings on approximately 11,000 steel services
- Couplings on the original, approximately 4.5 miles of 12" header main
- Other capitalized costs (labor, benefits, overheads)

The Eligible GIRC Property will be booked to the following FERC plant accounts where GIRC costs will be separately identifiable. Other capitalized costs such as labor charges, related benefits, and other appropriate overheads will also be booked to the appropriate FERC account and will be separately identified.

All GIRC costs must be tracked and accounted for separately from all other costs such that for any given calendar year GIRC costs are readily identifiable and trackable and shall be subject to audit by the Commission.

- **Account 376** - Mains and related parts and fittings such as couplings, valves, excess flow valves, risers, etc. booked to this account Piping (account 376);
- **Account 378** - Measuring and regulating equipment, insulated and non-insulated fittings;
- **Account 380** - Gas services lines and related parts and fittings;
- **Account 381** - Meters;
- **Account 382** – Meter Installations, meter bars, etc.;

Commission Filings
EWM will file by November 1 of each calendar year its GIRC Plan for the following year. That plan shall detail all DIMP related projects and projected costs.

EWM will file its GIRC Cost Calculation filing by May 1 of each year to recover the GIRC costs from the previous calendar year. The GIRC Calculation filing will contain all information necessary to calculate the annual GIRC costs and a proposed rate design. The first Commission GIRC Plan filing will be due November 1, 2018 for calendar year 2019. The first GIRC Calculation filing will be made by May 1, 2020 for recovery of 2019 eligible GIRC costs. The monthly charge derived from the GIRC Calculation filing will be effective on the first billing cycle in September, beginning in 2020.

COMPUTATION OF THE GIRC

Determination of GIRC Revenue Requirement to be Recovered. The revenue requirement recovery of the costs of GIRC eligible distribution system improvements projects will consist of a pre-tax return on the GIRC Eligible Net Plant plus depreciation.

Formula:
The formula for calculation of the GIRC Revenue Requirement is as follows:

GIRC = (NP * PTRR) + DEPR

Where:

Current Year = Current Year is defined as the calendar year for which the GIRC Cost Calculation Filing is seeking recovery of GIRC costs. For example, for a filing made in May, 2020 to recover GIRC Costs for the year 2019, the Current Year is defined as 2019.

Net Plant (NP) = NP shall be calculated by subtracting AD, EDIT, and Deferred Tax Benefits (2019 only) from GP as defined below.

Gross Plant (GP) = GP is the cumulative total of all previous calendar years original cost investment in GIRC Eligible Property, plus the 13 month average GIRC original cost investment for the current year.

Accumulated Depreciation (AD) = AD is the accumulated GIRC related depreciation as booked at the end of the current year.

EDIT – EDIT is the annual total credit due to customers to reflect the annual amortization of the Excess Deferred Income Tax balance resulting from the 2017 Tax Act and Jobs Cut. The EDIT deduction from GP will be booked as zero cost customer contributed capital and is cumulative.

Deferred Tax Benefits– For the GIRC Calculation to be filed in 2020 only, the EDIT amortization associated with year 2018 and the deferred tax benefits resulting from the change in statutory tax rate accrued from Jan. 1, 2018 until Sept. 30, 2018 will be applied as an offset against the GIRC GP investment of 2019, in addition to the application of EDIT associated with year 2019. The Deferred Tax Benefit deduction from GP will be treated as zero cost customer contributed capital for the five year period 2019 through 2023.

Pre-Tax Return Rate (PTRR) = The pre-tax return shall be calculated using the statutory state and federal income tax rates, the Utility's capital structure and cost rates for long-term and short-term debt as reflected in the most recent base rate case. The cost of equity will be the equity return rate approved in the last base rate case for which a final order was entered. The pre-tax return for EWM, based on the D2017.9.80 approved capital structure and long and short term debt costs and return on equity, is 8.75%. (CBGC is 8.81%.)

Depreciation Expenses (DEPR) = DEPR related to GIRC-Eligible Property. Annual depreciation expense shall be calculated by applying the annual accrual rates employed in the Utility's most recent base rate case for the plant accounts in which each retirement unit of GIRC-Eligible Property is recorded to the original cost of GIRC-Eligible Property. DEPR equals the total amount of GIRC related depreciation expenses booked in the current year.

Rate of Return Recovery Limitation: The GIRC surcharge will be subject to a review of the utility's overall rate of return as normalized for weather and filed in the Annual Report with the Commission on or before May 1. In any year where the reported rate of exceeds the most recent authorized rate of return (defined as the overall allowed weighted cost of capital), a reduction will be made to the GIRC Revenue Requirement by the amount of incremental revenue that results in the over-earning rate of return portion. The GIRC will not be permitted to be negative, unless the surcharge would be set to zero either because of the Rate of Return Recovery Limitation or in a situation where GIRC has no incremental amount of capital spending because it is not in excess of depreciation, in which case the surcharge will be the negative value associated with the tax benefits due to be applied to GIRC's costs.

Recovery of GIRC Program Revenue Requirement

The GIRC approved revenue requirement will be recovered through a monthly customer charge. These charges will vary by customer class and will be based on the customer class allocation factors established in the current general rate case D2017.9.80. The GIRC surcharge will be

separately disclosed on customers' monthly bills.

GIRC Termination

The GIRC surcharge automatically terminates if EWM files a rate case prior to Oct. 1, 2023. The GIRC charge automatically terminates on June 1, 2025. The GIRC surcharge automatically terminates if at any time EWM files an application pursuant to Mont. Code Ann. § 69-3-308 (state and local tax tracker). Costs associated with GIRC are recoverable through a rate case filing. If EWM/CBGC desires to renew the GIRC program, it will request to do so in the general rate case filing.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the Final Order issued on September 26, 2018 in Docket D2017.9.80 was served upon the following,

Mailing a true and correct copy:

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Dated: September 26, 2018

/s/*Sydney Kessel*
Sydney Kessel, Administrative Assistant

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1300

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC	)	ORDER ACCEPTING
For Adjustment of Rates and Charges	)	STIPULATIONS, GRANTING
Applicable to Electric Service in North Carolina	)	PARTIAL RATE INCREASE, AND
and Performance Based Regulation	)	REQUIRING PUBLIC NOTICE

HEARD: Monday, March 6, 2023, at 7:00 p.m., Haywood County Courthouse, Courtroom 2-A, 285 N. Main Street, Waynesville, North Carolina

Monday, March 13, 2023, at 7:00 p.m., Person County Courthouse, Superior Courtroom, 105 S. Main Street, Roxboro, North Carolina

Tuesday, March 14, 2023, at 7:00 p.m., Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina

Monday, March 20, 2023, at 7:00 p.m., Greene County Courthouse, 301 N. Green Street, Courtroom 1, Snow Hill, North Carolina

Tuesday, March 21, 2023, at 7:00 p.m., Robeson County Courthouse, Courtroom B, 500 N. Elm Street, Lumberton, North Carolina

Thursday, April 20, 2023, at 6:00 p.m. via Videoconference, Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina

Thursday, May 4, 2023, at 2:00 p.m., Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland; Daniel G. Clodfelter; Kimberly W. Duffley; Jeffrey A. Hughes; Floyd B. McKissick, Jr.; and Karen M. Kemerait

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BY THE COMMISSION: On June 8, 2022, pursuant to Rule R1-17B(c) of the Rules of Practice and Procedure of the North Carolina Utilities Commission, DEP filed its Request to Initiate Technical Conference Regarding the Projected Transmission and Distribution Projects to be Included in a Performance-Based Regulation (PBR) Application.

On September 6, 2022, pursuant to Commission Rule R1-17(a), DEP filed notice of its intent to file a general rate case application that includes a performance-based regulation application as authorized under N.C. Gen. Stat. § 62-133.16.

On October 6, 2022, DEP filed its Application to Adjust Retail Rates and for Performance-Based Regulations, and Request for an Accounting Order (the Application), supported by a Rate Case Information Report Commission Form E-1 (Form E-1), and direct testimony and exhibits. As required by N.C.G.S. § 62-133.16 and Commission Rule R1-17B, DEP's PBR Application included a residential decoupling rate-making mechanism, performance incentive mechanisms (PIMs) and tracking metrics, and a Multiyear Rate Plan (MYRP), including an earnings sharing mechanism (ESM).

PROCEDURAL HISTORY AND JURISDICTION

Procedural History

The following is a summary of the most pertinent filings by DEP, the parties, and procedural orders issued by the Commission.

Petitions to intervene were filed by CIGFUR on June 13, 2022, and CUCA on June 16, 2022. The Commission entered orders granting the petitions to CIGFUR on June 15, 2022, and CUCA on June 22, 2022.

On June 15, 2022, the Commission issued an Order Scheduling and Setting Procedures for the Technical Conference. The Commission's Order established that the Technical Conference would be held in person on July 25, 2022, that DEP should make its Transmission and Distribution (T&D) Information Filing by July 15, 2022, and that parties would be allowed to file written comments on DEP's T&D Information Filing on or before July 25, 2022.

Notice of intervention and of intent to participate in the Technical Conference was filed by the Attorney General's Office (AGO) on June 29, 2022.

Petitions to intervene and notices of intent to participate in the Technical Conference were filed by North Carolina Electric Membership Corporation (NCEMC) on June 30, 2022; NCJC, NCHC, SACE, and NCSEA on July 5, 2022; Vote Solar on July 11, 2022; and NRDC on July 11, 2022. The Commission entered orders granting the petitions of NCJC, NCHC, SACE, and NCSEA on July 7, 2022; Vote Solar on July 12, 2022; and NRDC on July 13, 2022. The Commission denied NCEMC's petition to intervene and granted NCEMC amicus curiae status on July 11, 2022.

CIGFUR also filed a notice of intent to participate in the Technical Conference on July 11, 2022. Notice of the Public Staff's intent to participate in the Technical Conference was filed by the Public Staff on July 11, 2022.

On July 15, 2022, DEP filed its T&D Information Filing. Comments in response to DEP's T&D Informational Filing were filed by the Public Staff, CIGFUR, NCSEA, and NCJC, et al. on July 25, 2022.

On July 25, 2022, a technical conference was held before the Commission with Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland; Daniel G. Clodfelter; Kimberly W. Duffley; Jeffrey A. Hughes; Floyd B. McKissick, Jr.; and Karen M. Kemerait.

On August 3, 2022, DEP filed a letter advising that it would provide the additional information in response to Chair Mitchell's request that it identify "Red Zone" projects and associated cost-benefit analyses (CBAs) included in DEP's T&D Information Filing, as part of DEP's direct testimony to be filed on August 19, 2022, in Docket No. E-100, Sub 179.

On September 6, 2022, pursuant to Commission Rule R1-17(a), DEP filed notice of its intent to file a general rate case application that includes a performance-based regulation application as authorized under N.C.G.S. § 62-133.16.

On September 12, 2022, pursuant to N.C.G.S. § 62-69, DEP, Duke Energy Carolinas, LLC (DEC), the Public Staff, CIGFUR, and Carolina Industrial Group for Fair Utility Rates III (CIGFUR III), filed the Agreement and Stipulation of Partial Settlement regarding the cost of service study (COSS Stipulation) for consideration by the Commission in Docket Nos. E-2, Sub 1300 and E-7, Sub 1276. On September 13, 2022, a revision to the Stipulation was filed by the aforementioned parties attaching exhibits which were inadvertently omitted from the version filed the previous day.

On October 6, 2022, DEP filed its Application, Form E-1, and the direct testimony and exhibits of Stephen G. De May, North Carolina President, DEP, DEC, and Progress Energy, Inc.; Jonathan L. Byrd, Managing Director of Rate Design and Regulatory Solutions for Duke Energy Business Services, LLC (DEBS); [1] Brent C. Guyton, Director of Asset Management in Customer Delivery for DEP and DEC; Laura A. Bateman, Vice President of Carolinas Rates and Regulatory Strategy; Phillip O. Stillman, Managing Director of Load Forecasting and Corporate Strategic Regulatory Initiatives; LaWanda M. Jiggetts, Rates and Regulatory Strategy Manager for DEC; Retha Hunsicker Vice President, Customer Experience Design and Solutions for DEBS; Tim S. Hill, Vice President, Coal Combustion Products (CCP) Operations, Maintenance and Governance for DEBS; Bradley G. Harris, Rates and Regulatory Strategy Director for DEBS; Janice D. Hager, President of Janice Hager Consulting, LLC; Tom Ray, Senior

[1] DEBS provides various administrative and other services to DEP and other affiliated companies of Duke Energy Corporation (Duke Energy).

Vice President of Nuclear Operations for Duke Energy Corporation (Duke Energy); Lesley G. Quick, Vice President of Customer Technology, Advocacy, Regulatory and Business Support within Customer Services for Duke Energy; Karl W. Newlin, Senior Vice President, Corporate Development and Treasurer, DEBS; Dr. Roger A. Morin, Emeritus Professor of Finance at the Robinson College of Business and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry, both at Georgia State University; Laurel M. Meeks, Director of Renewable Business Development for DEP; Evan W. Shearer, Principal Integrated Planning Coordinator for DEC; Daniel J. Maley, Director of Transmission Compliance Coordination for DEBS; Justin C. LaRoche, Director of Renewable Development for Duke Energy; Julie K. Turner, Vice President of Carolinas Coal Generation for Duke Energy; Kathryn S. Taylor, Rates and Regulatory Strategy Manager for DEC; Jacob J. Stewart, Director Health and Wellness for DEBS; Nicolas G. Speros, Director of Accounting for DEBS; John J. Spanos of Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming); and Teresa Reed, Director of Rates and Regulatory Planning for DEBS.

On October 31, 2022, the Commission issued an order which declared a general rate case, suspended the proposed new rates, established the test year period as ending December 31, 2021, and advised that an order scheduling hearings and requiring public notice would be issued at a later date.

Petitions to intervene were filed by Kroger Co. and Harris Teeter on November 4, 2022, and the Commercial Group on November 11, 2022. The Commission entered orders granting the petitions of the Commercial Group and Kroger Co. and Harris Teeter on November 15, 2022.

Petitions to intervene were filed by FPWC on November 23, 2022, and by the Sierra Club on December 14, 2022. The Commission entered orders granting the petitions of FPWC and the Sierra Club on January 10, 2023.

On December 16, 2022, the Commission issued an Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice (Scheduling Order). The Order scheduled public witness hearings in Lumberton, Raleigh, Waynesville, Roxboro, and Snow Hill, North Carolina on February 21, February 27, March 6, March 13, and March 20, 2023, respectively. Further, the order set the relevant test period to be used by all parties as the twelve-month period ending December 31, 2021, with appropriate adjustments. The Commission directed, among other instructions, that DEP publish the Public Notice of Hearings on Rate Increase Application (Public Notice) attached to the order as Appendix A, once a week for two consecutive weeks and mail the Public Notice to its customers no later than 30 days in advance of the first set hearing. Subsequently, on December 21, 2022, the Commission issued its Order Rescheduling Public Witness Hearings, Revising Public Notice, and Revising Requirement for Mailing Public Notice (Second Scheduling Order) correcting public hearing location addresses for Lumberton and Raleigh; rescheduling the public witness hearing in Lumberton to March 21, 2023, and the public witness hearing in Raleigh to March 14, 2023; authorizing corresponding

revisions to the Public Notice; and instructing DEP to mail each of its customers a copy of the Public Notice no later than 14 days in advance of the public witness hearing scheduled for March 6, 2023.

A petition to intervene was filed by DoD-FEA on January 30, 2023. The Commission entered an order granting DoD-FEA's petition on January 31, 2023.

On December 20, 2023, DEP filed a motion requesting leave to file direct testimony of Kendal C. Bowman adopting the direct testimony of Stephen G. De May, file the direct testimony and exhibits of Graham C. Tompson adopting the direct testimony of Laurel Meeks, and to amend the direct testimony of the Battery Energy Storage Panel. On January 10, 2023, the Commission entered an order granting DEP's motion filed December 20, 2023, and accepted the testimony and exhibits filed into the record.

A joint petition to intervene was filed by ElectriCities of North Carolina, Inc. (ElectriCities) and North Carolina Eastern Municipal Power Agency (NCEMPA) on February 1, 2023. The Commission entered an order denying Electricities' and NCEMPA's joint petition on February 10, 2023.

On February 13, 2023, DEP filed the supplemental direct testimony and exhibits of witnesses Jiggetts; LaRoche; Turner; Taylor; Martin M. Strasburger, Chief Security and Information Security Officer for Duke Energy; Reed; Ray; John R. Panizza, Director, Tax Operations for DEBS; Morin; Shearer; Graham C. Tompson, Business Development Manager for Duke Energy; Maley; Guyton; and Bateman.

On March 13, 2023, Haywood EMC filed a petition to intervene. On March 15, 2023, the Commission issued an order granting Haywood EMC's petition and establishing the scope of its intervention.

On March 14, 2023, the Commission issued its Order Scheduling Virtual Public Witness Hearing and Establishing Requirements for Notice of Virtual Public Witness Hearing (March 14, 2023 Scheduling Order). The March 14, 2023 Scheduling Order scheduled an additional virtual hearing for the purpose of receiving public witness testimony on DEP's Application for April 20, 2023.

On March 15, 2023, CCEBA filed a petition to intervene. On March 17, 2023, NCLM filed a Petition to Intervene. The Commission issued orders granting the petitions filed by CCEBA and NCLM on March 27, 2023.

In March, April, and May of 2023, the Commission held seven public hearings as scheduled by the Scheduling Order, Second Scheduling Order, and March 14, 2023 Scheduling Order for the purpose of receiving the testimony of public witnesses.

NCEMC filed a petition to intervene on March 17, 2023. The Commission issued an order denying NCEMC's Petition on March 28, 2023.

On March 27, 2023, the Commercial Group filed the direct testimony and exhibits of Steve W. Chriss, Director, Energy Services, Walmart; DoD-FEA filed the direct testimony and exhibits of Maureen L. Reno, Founder and Principal Consultant of Reno Energy Consulting Services, LLC, and Larry Blank, Principal of TAHOEconomics, LLC; NCLM filed the direct testimony of Terry Mann, Mayor of the City of Whiteville, North Carolina, and Bill Saffo, Mayor of the City of Wilmington, North Carolina; The Sierra Club filed the direct testimony and exhibits of Roger D. Colton, Co-Founder, Fisher, Sheehan, and Colton, Public Finance and General Economics and Michael Goggin, Vice President, Grid Strategies, LLC; NCJC, et al. filed the direct testimony and exhibits of John Howat, Senior Policy Analyst, National Consumer Law Center, Mark E. Ellis, independent consultant and testifying expert, David B. Posner, Manger, RMI and the joint direct testimony of David G. Hill, Managing Consultant at Energy Futures Group, Inc. and Jake Duncan, a Southeast Regulatory Director for Vote Solar; FPWC filed the direct testimony and exhibits of Laurie A. Tomczyk, Senior Manager, NewGen Strategies and Solutions, LLC; CIGFUR filed the direct testimony and exhibits of Michael P. Gorman, Managing Principal, Brubaker & Associates, Inc. and Nicholas Phillips, Jr., Principal, Brubaker & Associates, Inc.; Kroger Co. and Harris Teeter filed the direct testimony and exhibits of Justin Bieber, Principal, Energy Strategies, LLC; CUCA filed the direct testimony of Charles Heilig, President, Parkdale Mills, and Kevin W. O'Donnell, President, Nova Energy Consultants, Inc.; the AGO filed the direct testimony and exhibits of Edward Burgess, Senior Director of Integrated Resource Planning, Strategen Consulting, and Ron Nelson, Senior Director, Strategen Consulting.

Also on March 27, 2023, the Public Staff filed the direct testimony and exhibits of James S. McLawhorn, Director of the Energy Division of the Public Staff; Evan D. Lawrence, Engineer with the Energy Division of the Public Staff; Roxie McCullar, Consultant, William Dunkel and Associates; John W. Chiles, Principal, GDS Transmission Services group at GDS Associates, Inc.; Thomas C. Williamson, Engineer with the Energy Division of the Public Staff; Christopher C. Walters, Associate, Brubaker & Associates, Inc.; Blaise C. Michna, Engineer with the Energy Division of the Public Staff; Jay B. Lucas, Manager of the Electric Section, Operations and Planning in the Energy Division of the Public Staff; Jordan A. Nader, Engineer with the Energy Division of the Public Staff; Jeff Thomas, Engineer with the Energy Division of the Public Staff; David M. Williamson, Engineer with the Energy Division of the Public Staff; Dustin Metz, Engineer with the Energy Division of the Public Staff, the joint testimony and exhibits of Fenge Zhang, Financial Manager, Electric Section with the Accounting Division of the Public Staff, and Michelle Boswell, Director of Accounting for the Accounting Division of the Public Staff, and the joint testimony and exhibits of David M. Williamson and Jeff T. Thomas, Engineers with the Energy Division of the Public Staff.

On April 3, 2023, DEP filed a motion seeking to substitute Melissa B. Abernathy as the sponsor of the direct testimony and exhibits prefiled by Kathryn S. Taylor. On April 20, 2023, the Commission issued its Order Granting DEP's Motion for Substitution of Witness and Adoption of Testimony.

On April 14, 2023, DEP filed the rebuttal testimony and exhibits of DEP's witnesses Maley; Kevin A. Murray, Vice President of the Project Management and Construction Organization for DEBS; Morin; Bowman, President of Duke Energy's Utility Operations in North Carolina; Donna T. Council, Senior Vice President, Corporate Real Estate, Aviation, and Business Services for DEBS; LaRoche; Ray; Turner; Guyton; Panizza; Newlin; Quick; Speros; Spanos; Jiggetts; Melissa B. Abernathy, Director of Rates and Regulatory Planning for DEC; Stewart; and joint rebuttal testimony of witnesses Bowman, Quick, Abernathy, and Speros; Bateman and Stillman; Tompson and Shearer; Conitsha B. Barnes, Director of Energy Policy Management for DEC, Harris, and Quick; and Byrd and Reed.

On April 17, 2023, DEP filed amended rebuttal testimony of witness Morin.

On April 18, 2023, DEP filed second supplemental direct testimony of witness Reed and third supplemental direct testimony of witnesses Abernathy and Jiggetts.

On April 25, 2023, the Public Staff filed a motion to withdraw portions of witness Thomas' testimony. On May 1, 2023, the Public Staff filed a motion to withdraw portions of witness T. Williamson's testimony. On May 8, 2023, the Commission issued its order granting the Public Staff's motions to withdraw portions of testimony filed by witnesses T. Williamson and Thomas.

On April 26, 2023, the Public Staff and DEP filed an Agreement and Stipulation of Partial Settlement (April 26, 2023 Partial Settlement).

On April 27, 2023, the Commission issued its Order Continuing Hearing and Modifying Dates for Additional Hearing Procedures. Pursuant to the order, the expert witness hearing was rescheduled to commence on May 4, 2023. Also on April 27, 2023, the AGO filed its motion to substitute Ron Nelson as the sponsor of the testimony and exhibits filed by AGO witness Burgess. On May 8, 2023, the Commission issued its order granting the AGO's motion.

Also on April 27, 2023, the Public Staff filed a Transmission Cost Allocation Agreement and Stipulation of Settlement between DEP, DEC, and the Public Staff (TCA Stipulation).

On April 28, 2023, DEP filed settlement testimony of witness Bateman to support the TCA Stipulation. Also on April 28, 2023, DEP filed the settlement testimony and exhibits of witnesses Abernathy, Jiggetts, and Bowman in support of the April 26, 2023 Partial Settlement.

On May 1, 2023, DEP, the Public Staff, and CIGFUR filed an Agreement and Stipulation of Settlement on Performance Incentive Mechanisms, Tracking Metrics and Decoupling Mechanism (the PIMS Stipulation). Also on May 1, 2023, DEP and CIGFUR filed a separate Agreement and Stipulation of Settlement (the Power Quality Stipulation).

Additionally, on May 1, 2023, the Public Staff filed the supplemental and settlement joint testimony and exhibits of witnesses Zhang and Boswell; the supplemental testimony of witnesses Metz and Williamson; and the settlement testimony of witnesses Metz and McLawhorn in support of April 26, 2023 Partial Settlement.

On May 2, 2023, CIGFUR filed supplemental direct testimony of witness Phillips, Jr. in support of the Power Quality Stipulation. Also on May 2, 2023, DEP, the Public Staff, and CIGFUR filed an Amended Agreement and Stipulation of Partial Settlement that amended the April 26, 2023 Partial Settlement, including through the inclusion of CIGFUR as a party (as amended, the Revenue Requirement Stipulation). Also on May 2, 2023, the Public Staff filed the joint testimony of witnesses Thomas and D. Williamson and DEP filed the joint settlement testimony of witnesses Bateman and Stillman supporting the PIMS Stipulation.

On May 4, 2023, DEP, Sierra Club, NCJC, et al., and the Public Staff filed an Agreement and Stipulation of Partial Settlement Regarding Low-Income/Affordability Performance Incentive Mechanism and Affordability Issues (the Affordability Stipulation). On May 5, 2023, DEP filed the settlement testimony of witnesses Barnes, Harris, and Quick and the Public Staff filed testimony of witness D. Williamson in support of the Affordability Stipulation.

On May 4, 2023, the expert witness hearing commenced.

From May 5, 2023, through June 6, 2023, DEP filed 18 Late-Filed Exhibits, and the Public Staff filed Late-Filed Exhibit Nos. 1 and 2.

On May 10, 2023, DEP, the Commercial Group, and Kroger and Harris Teeter filed an Agreement and Stipulation of Settlement (MGS Partial Rate Design Stipulation).

On May 16, 2023, DEP filed a Notice of Intent to Place Temporary Rates into Effect and Request for Expedited Approval of Notice of Undertaking, as well as a revised Appendix A, and on May 17, 2023, a second revised Appendix A. Also on May 17, 2023, the Commission filed an Order Approving Public Notice of Temporary Rates Subject to Refund and Financial Undertaking and Expiration of EDIT-3 Rider.

On May 23, 2023, DEP filed its Temporary Rates Compliance Filing.

On May 26, 2023, the Public Staff filed a Motion to Strike Portions of DEP's Late-Filed Exhibits 9 and 10, which DEP filed a response to on May 30, 2023. On June 2, 2023, the Commission issued an Order Denying the Public Staff's Motion to Strike Portions of DEP's Late-Filed Exhibits 9 and 10.

On June 7, 2023, DEP and CIGFUR filed an Agreement and Stipulation of Settlement (the LGS Partial Rate Design Stipulation).

On June 27, 2023, the Public Staff filed the second supplemental testimony of witnesses Zhang and Boswell, the second supplemental testimony of witness D. Williamson, and the supplemental testimony of witness Thomas. On that same date, DEP and the Public Staff filed an Agreement and Stipulation of Settlement (the Supplemental Revenue Requirement Stipulation) and the Public Staff filed the supplemental settlement testimony of Metz, Zhang, and Boswell.

On June 27, 2023, the Public Staff filed a Motion for Leave to File Testimony on the June 7, 2023 Stipulation filed between DEP and CIGFUR.

On June 28, 2023, the Public Staff filed the corrected second supplemental exhibits of witness D. Williamson.

On July 3, 2023, CIGFUR filed a motion to strike the second supplemental testimony and corrected second supplemental exhibits of Public Staff witness D. Williamson. On that same date, CIGFUR filed in opposition to the Public Staff's motion for leave to file testimony on the June 7, 2023 Stipulation.

On July 3 and 5, 2023, DEP, NCLM, and the Public Staff filed responses to the July 3, 2023 CIGFUR filings.

On July 6, 2023, the Commission issued an Order on Post-Hearing Motions and Reconvening Hearing which denied CIGFUR's motion to strike the second supplemental testimony and corrected second supplemental exhibits of Public Staff witness D. Williamson, denied the motion for leave of the Public Staff to file testimony on the June 7, 2023 Stipulation, and reconvened the expert witness hearing for limited purposes.

On July 24, 2023, the expert witness hearing was reconvened.

Jurisdiction

No party has contested the fact that DEP is a public utility subject to the Commission's jurisdiction pursuant to the Public Utilities Act (Act), Chapter 62 of the North Carolina General Statutes. The Commission concludes that it has personal jurisdiction over DEP and subject matter jurisdiction over the matters presented in DEP's Application.

Application

In summary, DEP requested in its Application and initial direct testimony and exhibits, a base rate increase of approximately $227.6 million, or 5.9%, in its annual electric sales, offset by a rate reduction of $8.5 million to refund certain tax benefits, for a net revenue increase of $219.2 million, or 5.7% from its North Carolina retail electric operations, including a rate of return on common equity of 10.2% and a capital structure consisting of 47.0% debt and 53.0% equity. DEP's Application and initial direct testimony and exhibits also sought approval of PBR and a series of rate increases based on DEP's proposed three-year MYRP, and other mechanisms required as part of PBR, with the first

rate increase effective November 5, 2022. DEP sought increases to the revenue requirement of $106.6 million, $150.8 million, and $138.3 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

DEP submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ending on December 31, 2021, adjusted for certain known changes in revenue, expenses, and rate base through March 31, 2023[2].

DEP, by its supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $283.5 million, offset by a rate reduction of $8.5 million to refund certain tax benefits, for a net revenue increase of $275 million, including an increase to the rate of return on common equity to 10.4% and an increase to the cost of debt to 3.88% based on the average embedded cost of debt financing as of December 31, 2022. DEP also revised its series of rate increases based on DEP's proposed three-year MYRP. DEP's updated MYRP revenue requirements were $104 million, $133.4 million, and $147.5 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

DEP, by its second supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $308.8 million, offset by a rate reduction of $8.5 million to refund certain tax benefits, for a net revenue increase of $300.3 million including an increase to the cost of debt to 3.9% based on the average embedded cost of debt financing as of February 28, 2023. DEP also revised its series of rate increases based on DEP's proposed three-year MYRP. DEP's updated MYRP revenue requirements were $104.1 million, $133.5 million, and $147.6 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

DEP, by its March 2023 supplemental direct testimony and exhibits, revised its requested base revenue requirement increase to approximately $314.6 million, offset by a rate reduction of $8.5 million to refund certain tax benefits, for a net revenue increase of $306.1 million, including an increase to the cost of debt to 4.03% based on the average embedded cost of debt financing as of March 31, 2023. DEP also revised its series of rate increases based on DEP's proposed three-year MYRP. DEP's updated MYRP revenue requirements were $104.5 million, $133.5 million, and $148.2 million in Rate Year 1, Rate Year 2, and Rate Year 3, respectively.

[2] DEP's Application initially proposed a capital cut-off date of April 31, 2023; however, upon further discussion and agreement with the Public Staff, the parties agreed to, and the Commission's Scheduling Order established, a capital cut-off date of March 31, 2023. The change in capital cut-off was reflected in DEP's supplemental filings.

Whole Record

The Commission held public witness hearings as noted above. The following public witnesses appeared and testified:

Waynesville: Les Cochran, Charles Guyton, Andrew Jarbeau, Porter Hughes, Gray Jernigan, Rob Denton, Mary Curry, Walker Spruill, Delisa Ensley, Ken Brame, Judy Mattox, Abby Frye, and Angelica Cote.

Raleigh: William Terry, Criss Berke, Amelia Covington, Divine Earth-Dowd, Jennifer Eison, Stacey Campbell, Paul Baer, Lisa Brewer, Peter Thomas, Agnes Foucha, Ashleigh Armstrong, Ziyad Habash, Ebony McKinnan, Cathy Buckley, Deborah Ford, Ernestine Ledbetter, Matthew Muse, Eleanor Weston, Kaitlyne Sheehan, and Brenda Jackson.

Snow Hill: Gwen Johnson, David Barnes, Phyllis Merritt-James, Brianna Howard, Jaylind Lampa, Larry James, Glenda Thomas, Vicky Bailey, Barbara Dantonio, Don Cavellini, Beatrice Jones, Syene Jasmin, Bobby Jones, and Constance Coram.

Lumberton: Debra David, Robert Macy, Jaquline Banks; Les Cochran; Sallie McLean; Lauren Martin; Samantha Sirabian; Daniel Dimaria, Hannah Jeffries, Esther Murphy, Ryua Hishikawa, Georgette Hunt, Mac Legerton, Ricky Johnson, Felicia Bethea, Carol T. Richardson, Frankie Hall, and William Fairley.

Virtual Hearing: Michael Righi, Reagan McGuinn, Ruby Bell, Kay Reibold, Steven Norris, Sean Lewis.

In summary, almost all the public witnesses stated their opposition to DEP's proposed rate increase. *See generally*, Tr. vols. 2-6. Many witnesses testified that they were on fixed incomes and about the poverty in some of the counties served by DEP. Moreover, public witnesses testified to their concern regarding DEP's use of fossil fuels, including coal and natural gas power plants, fracking, and DEP not adequately increasing the use of clean energy and renewables. Finally, some public witnesses voiced their view that DEP's executive compensation and shareholder dividends are excessive.

In addition to the public witness testimony, the Commission received a number of consumer statements of position, all of which were filed in the docket. *See generally*, Docket No. E-2, Sub 1300CS. The public witness testimony and consumer statements of position have been considered by the Commission in its deliberations on DEP's rate case Application.

The testimony and exhibits in this proceeding are voluminous. The Commission has carefully considered all the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witness in this Order.

Rather, the Commission has summarized the evidence that is in the record. Likewise, while the Commission has read and fully considered the parties' post-hearing briefs, it has not in this Order attempted expressly to summarize or discuss every contention advanced or authority cited in the briefs.

Based upon the foregoing and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

Stipulations

1. On April 26, 2023, DEP and the Public Staff filed the Revenue Requirement Stipulation, which resolved a portion of the base period and MYRP revenue requirement issues in this proceeding. On May 2, 2023, DEP and the Public Staff amended the Revenue Requirement Stipulation, adding CIGFUR as a party and resolving an additional revenue requirement issue.

2. On September 13, 2022, DEP, DEC, the Public Staff, CIGFUR, and CIGFUR III (the COSS Stipulating Parties) filed the COSS Stipulation. The COSS Stipulation provides that DEP will first allocate production and transmission demand costs to the North Carolina retail jurisdiction using the Twelve Coincident Peak (12 CP) method and will allocate production demand costs among the North Carolina retail rate classes using the modified Average and Excess (A&E) Demand Method (the Modified A&E Method).

3. On April 27, 2023, DEP, DEC, and the Public Staff filed the TCA Stipulation. The TCA Stipulation provides for a pro forma adjustment of approximately $20 million to increase the revenue requirement in DEC's pending rate case proceeding in Docket No. E-7, Sub 1276 (DEC Rate Case) and to decrease the revenue requirement in the instant proceeding.

4. On May 1, 2023, DEP, the Public Staff, and CIGFUR filed the PIMs Stipulation.

5. On May 1, 2023, DEP and CIGFUR filed the Power Quality Stipulation.

6. On May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation.

7. On May 10, 2023, DEP, the Commercial Group, and Kroger Co. and Harris Teeter filed the MGS Partial Rate Design Stipulation.

8. On June 7, 2023, DEP and CIGFUR filed the LGS Partial Rate Design Stipulation.

9. On June 27, 2023, DEP and the Public Staff filed the Supplemental Revenue Requirement Stipulation.

10. The Revenue Requirement Stipulation, the COSS Stipulation, the TCA Stipulation, the PIMs Stipulation, the Power Quality Stipulation, the Affordability Stipulation, the MGS Partial Rate Design Stipulation, the LGS Partial Rate Design Stipulation, and the Supplemental Revenue Requirement Stipulation are the product of give-and-take settlement negotiations between the respective stipulating parties.

Depreciation

11. The depreciation rates proposed by DEP, which reflect the accelerated retirement of DEP's coal units, as amended by the Revenue Requirement Stipulation to reflect 20-year amortization periods for General Plant FERC accounts 391 and 397 and a 70-year life for Transmission FERC account 356, are reasonable.

12. The deferral of 75.0% of the impact of accelerating the depreciation of DEP's Mayo and Roxboro Units 3 and 4 from the current retirement dates to a regulatory asset as agreed upon in the Revenue Requirement Stipulation is reasonable.

13. Any portion of net book value upon the retirement of DEP's subcritical coal-fired plants that will not be recovered through securitization will be recovered with a return over an amortization period to be determined by the Commission in a future rate case proceeding.

Base Period Plant-Related Items

14. DEP's plant-related capital investments during the test year in its transmission, distribution, fossil/hydro, nuclear, solar, and storage assets, as adjusted by the Revenue Requirement Stipulation, were prudently and reasonably made and should be reflected in the revenue requirement.

Grid Improvement Plan Costs

15. Since DEP's last general rate case, DEP has deferred incremental operation and maintenance expense, depreciation and property taxes associated with its three-year grid improvement plan (GIP), as well as the carrying cost on the investment and the deferred costs at DEP's weighted average cost of capital.

16. DEP proposes to amortize the GIP deferral of $36.4 million, associated with the GIP investment of $196.7 million on a North Carolina retail basis, over an amortization period of three years, which results in an annual amortization expense of $12.9 million.

17. Section III, Paragraph 11 of the Revenue Requirement Stipulation provides that DEP should be permitted to recover the full balance of its GIP deferral over an amortization period of 18 years, with a debt-only return during the deferral period and rate

base treatment during the amortization period.

Coal Ash

18. DEP's request to amortize costs associated with its coal combustion residual (CCR) obligations incurred through March 31, 2023, over a five-year period and to continue the deferral of any CCR costs incurred subsequent to March 31, 2023, is reasonable.

19. The over-amortization of CCR recovery in the amount of $8.5 million should be applied against the Coal Ash CCR Asset Retirement Obligations (ARO) deferral.

Harris Land Sales

20. Section III, Paragraph 22 of the Revenue Requirement Stipulation provides for a flowback period of three years for the liability related to the gains on Harris land sales and provides that DEP will include the unamortized balance in rate base.

21. It is appropriate for DEP to continue to defer any gains on Harris land sales to be returned to customers in a future general rate case proceeding.

Roxboro Wastewater Treatment Regulatory Asset

22. DEP's request for an accounting order to establish a regulatory asset upon the retirement of the Roxboro Wastewater Treatment Plant in which to defer the unrecovered remaining net book value of the plant and costs related to obsolete inventory, net of salvage was approved in the Commission's Order in DEP's last general rate case proceeding in Docket No. E-2, Sub 1219 (the 2019 Rate Case).

23. Section III, Paragraph 24 of the Revenue Requirement Stipulation establishes an amortization period of 12 years for the recovery of the deferred balance associated with the Roxboro Wastewater Treatment Facility and that the unamortized balance will be included in rate base.

Storm Securitization Over Collections

24. Per DEP's Agreement and Stipulation of Partial Settlement with the Public Staff in Docket No. E-2, Sub 1262, DEP agreed to establish regulatory asset or regulatory liability accounts for the purpose of tracking up-front financing costs and servicing and administration fees related to storm securitization.

25. The amortization over three years of the regulatory liability for the over-recovered balance of $0.9 million for storm securitization over collections is just and reasonable.

Cost of Debt

26. The embedded cost of debt of 4.03% as set forth in Section III, Paragraph 1 of the Revenue Requirement Stipulation is reasonable and appropriate for use by DEP in this case.

Accounting Adjustments

27. The accounting adjustments set forth in the Revenue Requirement Stipulation, as further described in detail in Jiggetts Partial Settlement Exhibit 2 and the Public Staff Accounting Supplemental and Settlement Exhibit 1, Schedule 1, are the reasonable product of give-and-take negotiations among the parties.

28. The accounting adjustments set forth in the Supplemental Revenue Requirement Stipulation, as further described in detail in Supplemental Revenue Requirement Stipulation Exhibit 1, are the reasonable product of give-and-take negotiations between the stipulating parties.

MYRP Capital Investments

29. DEP's proposed MYRP capital investments, reflecting the projected costs associated with the transmission, distribution, fossil/hydro, nuclear, cybersecurity, solar, and storage capital investments, as adjusted in the Revenue Requirement Stipulation, are just and reasonable to all parties in light of the evidence the parties presented, consistent with statutory and regulatory requirements, and appropriate for approval as part of DEP's overall Application in this proceeding.

Reporting Requirements

30. Section IV of the Revenue Requirement Stipulation establishes several reporting obligations of DEP.

Storm Normalization

31. The adjustment to DEP's revenue requirement, calculated using the method approved by the Commission in Docket Nos. E-2, Sub 1023, E-2, Sub 1142, and E-2, Sub 1219 to account for anticipated storm expenses based upon a 10-year average of storm costs after removing costs associated with major storms, is approximately $22.243 million.

DSDR

32. DEP has requested approval to recover the future costs associated with its Distribution System Demand Response (DSDR) energy efficiency program through base rates in lieu of the Demand-Side Management/Energy Efficiency (DSM/EE) rider, beginning with the rates established in this proceeding.

Payment Navigator

33. DEP has requested approval for its Payment Navigator program, which is designed to provide support to customers in need of assistance with managing payment of their electric bills, and the request is reasonable.

Customer Connect

34. DEP has proposed to recover approximately $60 million associated with the implementation of the Customer Connect platform, which is DEP's customer engagement platform, and the Customer Information System (CIS).

COSS Stipulation

35. The COSS Stipulation between DEP, DEC, CIGFUR, and the Public Staff, requires DEP to allocate production demand and transmission demand costs by using the 12 CP allocation method for jurisdictional allocations and the Modified A&E method among North Carolina retail customer classes.

Transmission Cost Allocation Stipulation

36. The TCA Stipulation establishes a pro forma adjustment to increase the revenue requirement for DEC in the DEC Rate Case by approximately $20 million on a North Carolina retail basis as well as a corresponding decrease to the revenue requirement for DEP in the instant proceeding.

PIMs Stipulation

37. On May 1, 2023, DEP, the Public Staff, and CIGFUR filed the PIMs Stipulation.

38. The PIMs Stipulation consists of the following three PIMs: Time Differentiated and Dynamic Rate Enrollment PIM, Reliability PIM, and the Renewables Integration and Encouragement PIM (consisting of Metrics A, B, and C) (collectively, the Settled PIMs). The PIMs Stipulation also provides for three tracking metrics – customer service, beneficial electrification from incremental load of EVs, and reporting and analyzing the 10 worst performing circuits (collectively, the Settled Tracking Metrics) – and provides a process for DEP to work with the Public Staff to develop tariffs and programs to estimate and update revenue associated with EV sales.

Power Quality Stipulation

39. DEP and CIGFUR filed the Power Quality Stipulation, which has the objective of enabling DEP to analyze power quality issues.

Affordability Stipulation

40. On May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation, pursuant to which DEP and DEC agreed to make shareholder financial contributions totaling $16 million over three years to benefit eligible customers.

41. The Affordability Stipulation supports the Customer Assistance Program (CAP) and the corresponding tariffs associated with the CAP.

Rate Design

42. The objective of DEP's proposed rate design is to recover the revenue requirement while aligning the cost to serve customers within the customer classes and reflecting the costs a customer causes DEP to incur. DEP's proposed rate design allocates the revenue increase between customer classes by rate base amounts.

43. DEP's rate design involves adjustments that are intended to achieve DEP's rate design objective, including a subsidy reduction, a customer migration adjustment, and customer growth and weather normalization adjustments.

44. DEP proposes changes to residential rate schedules, the small general service (SGS) rate schedules, the medium general service (MGS) rate schedules, the large general service (LGS) rate schedules, the seasonal and intermittent rate schedules, the lighting rate schedules, and the traffic signal rate schedules.

45. DEP proposes changes to its service riders, which are offered to reflect the cost of meeting unique or special customer requirements.

46. DEP proposes updated and aligned TOU periods across its rate schedules that include time-differentiated pricing for residential and non-residential customers.

47. The MGS Partial Rate Design Stipulation, entered into by DEP, the Commercial Group, and Kroger Co. and Harris Teeter, provides that 75.0% of the reduction in revenue requirement, as determined by final Commission order, applicable to rate schedule MGS-TOU should be applied to energy rates.

48. LGS Partial Rate Design Stipulation, entered into by and between DEP and CIGFUR, provides that any increase in energy charges resulting from an increase in DEP's revenue requirement, which to be recovered from the LGS, LGS-TOU, and LGS-Real Time Pricing (RTP) rate schedules, as determined by final Commission order, shall be limited to a percentage that is less than half of the approved overall increase percentage to the LGS, LGS-TOU, and LGS-RTP classes, respectively, exclusive of any decrements for the LGS, LGS-TOU, and LGS-RTP rate schedules.

Capital Structure, Cost of Equity and Overall Rate of Return

49. DEP proposed a rate of return on common equity of 10.4%, with a capital structure consisting of 53.0% common equity and 47.0% debt.

50. The overall rate of return and rate of return on common equity must be supported by competent, material, and substantial record evidence; consistent with the requirements of N.C.G.S. § 62-133 considering changing economic conditions; and must balance DEP's need to maintain the safety, adequacy, and reliability of its service with the benefits to DEP's customers to receive from safe, adequate, and reliable electric service.

51. Ultimately, the capital structure, rate of return on common equity, and overall rate of return set by this Order must result in just and reasonable rates.

COVID Deferral Recovery

52. The Commission's December 21, 2021 Order in Docket No. E-2, Sub 1253 (Deferral Order) approved DEP's request to create a regulatory asset into which to defer incremental COVID-19 pandemic-related costs.

53. In this proceeding, DEP seeks to recover the deferred balance, including accrued carrying costs, of approximately $107 million related to: (1) customer fees waived; (2) bad debt charge-offs; (3) employee stipends to cover unplanned expenses associated with the COVID pandemic; (4) costs related to employee safety; (5) costs related to remote work; and (6) miscellaneous costs, such as employee overtime.

54. DEP identified and calculated two categories of COVID-related savings in the amount of approximately $4.5 million on a North Carolina retail basis related to: (1) reduced printing and postage costs due to the moratorium on customer disconnections; and (2) reduced travel expenses. DEP benefited from certain measures taken by the federal government to assist employers during the pandemic, including federal employee retention credits (ERCs) and the delay of payment obligation of the employer portion of social security tax.

55. DEP seeks to recover the deferred balance over a three-year period.

56. DEP requests to continue the deferral of the incremental bad debt, for future recovery.

Inflation Adjustment

57. DEP's calculation of the increase in Non-Labor and Non-Fuel Operating and Maintenance (O&M) costs due to the effect of inflation relies on the same method proposed and approved by the Commission in DEP's last three general rate cases.

Rate Case Expense

58. DEP proposes to recover additional rate case expense leftover from the 2019 Rate Case in this proceeding.

59. DEP proposes to recover rate case expenses, incurred in this proceeding over a three-year period.

60. DEP proposes to include the unamortized balance of rate case expense in rate base.

Over-Amortizations

61. DEP's approach to over-amortization of Commission-approved regulatory assets is to apply the amount of over-amortization for recovery of like kind expenses.

Storm Balancing Account and Winter Storm Izzy

62. DEP requested deferral of approximately $15 million in O&M costs associated with system restoration necessitated by Winter Storm Izzy, which occurred in January 2022.

63. DEP spent $87.126 million on a North Carolina retail jurisdictional basis in 2022 on annual storm costs (inclusive of both Winter Storm Izzy and Hurricane Ian, among other storms), which is beyond the normal range of fluctuation of storm costs of $27.4 million.

64. DEP and the Public Staff agree on the amount of $15 million of O&M costs to be recovered for Winter Storm Izzy but do not agree on the method of recovery.

65. DEP proposes to recover 2022 incremental Winter Storm Izzy costs by applying a portion of the $17 million over-amortization of Hurricane Matthew costs from the DEP's general rate case proceeding from 2017 in Docket No. E-2, Sub 1142 (the 2017 Rate Case).

66. DEP proposes to create a storm balancing account that would, in essence, operate as a rider or tracker. DEP proposes to use the remaining amount of over-amortization of Hurricane Matthew costs, approximately $2 million, to establish the storm balancing account.

Other Deferrals

67. DEP requests to defer the estimated tax benefits, net of costs, associated with the Inflation Reduction Act (IRA) and Infrastructure Investment Job Act (IIJA).

68. DEP has proposed three customer programs for approval by the Commission, the CAP, the Payment Navigator Program, and the Tariffed On-Bill Program.

69. DEP expects to incur incremental O&M costs related to the implementation of the CAP the Payment Navigator Program, and the Tariffed On-Bill Program, and implementation of the PIMs, including the required PIMs dashboard, and proposes to defer its incremental O&M costs associated with the implementation of the customer programs and PIMs.

Interconnection CIAC Regulatory Liability Recommendation

70. The Public Staff has identified an issue with respect to DEP's recording of contributions in aid of construction (CIAC) in the context of interconnection agreements (IA) between DEP and third party interconnection customers and proposed that a regulatory liability be established to record any instances in which DEP incorrectly recovered costs associated with interconnection agreements (IAs) from ratepayers.

Quality of Service

71. DEP and the Public Staff presented evidence as to the adequacy of electric service provided by DEP.

Tax-Related Items

72. DEP proposes revision to its previously approved North Carolina excess deferred income taxes (EDIT) rider (EDIT-4) to reflect additional amounts due to customers.

73. The levelized return rate should reflect a capital structure consisting of 47.0% long-term debt and 53.0% equity, a 4.03% embedded cost of debt, and a rate of return on equity of 9.8%.

Base Fuel and Fuel-Related Factors and Fuel Cost Allocation

74. DEP proposes to continue its use of the equal percentage fuel adjustment allocation methodology.

75. DEP proposes to allocate purchased power capacity costs to North Carolina retail and across North Carolina retail customer classes based on production demand.

Residential Decoupling Mechanism and Earnings Sharing Mechanism

76. DEP's PBR Application includes a residential decoupling mechanism, a rate-making mechanism intended to break the link between DEP's revenue and the level of consumption of electricity on a per customer basis by its residential customers, as required by N.C.G.S. § 62-133.16(c) and Commission Rule R1-17B.

77. DEP proposes as a component of the MYRP an ESM, an annual rate-making mechanism that shares surplus earnings between DEP and its customers over

the period of time covered by a MYRP, as required by N.C.G.S. § 62-133.16(c) and Commission Rule R1-17B.

Performance-Based Regulation

78. DEP filed its first PBR Application in accord with N.C.G.S. § 62-133.16 and with Commission Rule R1-17B.

Revenue Requirement

79. After giving effect to the portions of the stipulations approved herein and the Commission's decision on contested issues, the annual revenue requirement for DEP for Rate Years 1, 2, and 3 will allow DEP a reasonable opportunity to recover its operating costs and earn the overall rate of return on its rate base that the Commission has found just and reasonable upon consideration of the findings in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-10

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the stipulations between DEP and the other parties; the testimony and exhibits of DEP witnesses Bowman, Abernathy, Hager, Bateman, Stillman, Barnes, Harris, Quick and Jiggetts; Public Staff witnesses Zhang, Boswell, McLawhorn, D. Williamson, Thomas, and Metz; CIGFUR witness Phillips; and the entire record in this proceeding.

Revenue Requirement Stipulation

On April 26, 2023, the Public Staff and DEP filed the Revenue Requirement Stipulation resolving a portion of the revenue requirement issues between the parties. On May 2, 2023, DEP and the Public Staff amended the stipulation to include CIGFUR as a party and resolve among themselves an additional issue pertaining to vegetation management.

Witness Bowman testified that the stipulation resolves most of the revenue requirement issues between DEP and the Public Staff. She stated that the parties fully resolved the recovery of capital projects and related costs to be included in DEP's MYRP. Tr. vol. 7, 53-54. Witness Bowman also testified that the parties reached agreement on the inclusion of plant in service and depreciation rates and agreed to revenue requirement adjustments for the following items: cost of debt; executive compensation; board of directors expenses; rent expenses; lobbying; sponsorships and donations; incentive compensation; reliability assurance operations and maintenance (O&M) spend; aviation expenses; non-residential credit card fees; end of life nuclear reserve; coal inventory; salaries and wages; gain on Harris land sales; production O&M; and the treatment of various deferrals DEP is requesting to recover. *Id.* She explained that the Revenue Requirement Stipulation shows these accounting and ratemaking adjustments and the resulting effect on the revenue requirement. Witness Bowman also testified to DEP's commitment to perform a lead-lag study before its next rate case application and agreement to various reporting obligations. *Id*. Witness Bowman further testified that the stipulation represents a balanced settlement between the stipulating parties on the settled issues, is in the public interest, and should be approved by the Commission. *Id.*

Public Staff witnesses McLawhorn, Metz, Zhang, and Boswell testified that, from the Public Staff's perspective, the most important benefits the stipulation provides are: (1) an aggregated reduction in DEP's proposed revenue increase resulting from the agreed-upon adjustments; and (2) the avoidance of protracted litigation between DEP and the Public Staff before the Commission and possibly the appellate courts on the settled issues and the associated increased rate case expense recovery from customers. Tr. vol. 16, 514; Tr. vol. 19, 87. Based on these ratepayer benefits, and other provisions of the stipulation, the Public Staff believes the stipulation is in the public interest and that the Commission should approve it. *Id.*

Sections III and IV of the Revenue Requirement Stipulation outline several accounting and ratemaking adjustments, as well as reporting obligations, to which DEP,

the Public Staff, and CIGFUR agree. The Commission fully discusses these agreed-upon issues later in this Order.

COSS Stipulation

On September 13, 2022, the COSS Stipulating Parties filed the COSS Stipulation with the Commission. Tr. vol. 11, 80. The COSS Stipulation provides that DEP will first allocate production and transmission demand costs to the North Carolina retail jurisdiction using the 12 CP method and then will allocate production demand costs among North Carolina retail customer classes using the Modified A&E method. *Id.* Because transmission demand does not have average or excess energy components, the transmission demand factors at the customer class level are equivalent to the 12 CP calculation. *Id.* The COSS Stipulation also provides that, for purposes of allocating production demand costs on a jurisdictional basis as well as to North Carolina retail rate classes, DEP will make an adjustment to exclude certain curtailable/interruptible loads if they were not curtailed at the twelve system peak hours during the test year. *Id.* The COSS Stipulation only applies in the current rate case, and the COSS Stipulating Parties are free to advocate for different methodologies in future DEP cases. *Id.* DEP witness Hager testified that the stipulation is reasonable and that the Commission should approve it, noting that it was the result of give-and-take negotiations of parties with diverse views on the appropriate methodologies reaching a settlement. *Id.* at 80-81.

TCA Stipulation

On April 27, 2023, DEP, DEC, and the Public Staff filed the TCA Stipulation. The TCA Stipulation sets forth the agreement of the parties thereto to a pro forma adjustment of approximately $20 million to increase the revenue requirement in the pending DEC Rate Case and to decrease the revenue requirement in the instant proceeding.

The TCA Stipulation calculates a pro forma amount of transmission expense for DEC and transmission revenue for DEP by multiplying the net transfers from DEP to DEC which occurred in 2022 pursuant to the joint dispatch agreement (JDA)[3]by the DEP non-firm transmission rate established in the FERC-approved Joint Open Access Transmission Tariff (OATT) of DEP, DEC, and Duke Energy Florida, LLC.[4] The stipulation also provides that the adjustment is for North Carolina ratemaking purposes only and will not change the terms or conditions of the JDA or result in any accounting entries for DEP or DEC. The TCA Stipulation provides that the adjustment will become effective on

[3] The JDA is the framework by which DEC and DEP manage and utilize their electric generation assets jointly to serve their respective retail customers with the most efficient generating plants available on a daily basis and was approved by the Commission as a part of the 2012 merger of DEP and DEC. Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, Docket Nos. E-7, Sub 986, and E-2, Sub 998, June 30, 2012.

[4] DEC OATT Transmission Rate Formula Template Using Form 1-Data Utilizing Cost Data for (Historic Years) with Year-End Average Balances Development of Revenue Requirement OATT, p. 3 of 7 (328 of 1170); DEP OATT Transmission Non-Levelized Rate Formula Template Using Form-1 Data Development of Revenue Requirement, p. 3 of 5 (510 of 1170).

October 31, 2023 for both DEP and DEC, and will terminate at the sooner of the effective date of rates in DEP's or DEC's next general rate case or the effective date of a full merger of DEP and DEC, unless the Commission orders otherwise.

DEP witness Bateman testified in support of the TCA Stipulation. Tr. vol 14, 146. She explained that the TCA Stipulation is the result of substantial discovery and extensive negotiation among the stipulating parties and that it reflects a constructive near-term approach to addressing rate disparity concerns arising from the increasing net transfers of energy from DEP to DEC under the JDA. *Id.* Public Staff witness Metz also testified in support of the TCA Stipulation. Tr. vol. 16, 517-18. Witness Metz testified that the TCA Stipulation addresses the growing level of net transfers and the subsequent rate disparity between DEP and DEC in North Carolina and explained that the adjustment will compensate DEP and DEC ratepayers for the use and annual maintenance of each utility's transmission system for energy transfers under the JDA. *Id.*

PIMs Stipulation

On May 1, 2023, the DEP, the Public Staff, and CIGFUR filed the PIMs Stipulation. The PIMS Stipulation reflects an agreement between the parties regarding certain of the PIMs, tracking metrics, and the electric vehicle (EV) adjustment to DEP's decoupling mechanism.

DEP's PBR Policy Panel provided testimony in support of the PIMs Stipulation. Tr. vol. 14, 131. The PBR Policy Panel testified that the resolution reached among the parties to the stipulation represents a balanced approach to achieving policy goals in DEP's first PBR Application. Tr. vol. 15, 17, 70. DEP witness Stillman testified that the settled PIMs originated from the North Carolina Energy Regulatory Process (NERP) PBR Working Group,[5] were informed by DEP's pre-filing PIM stakeholder process, and evolved over discussions among the parties in the instant proceeding. Tr. vol. 14, 132-33. DEP witness Bateman testified that the Commission must examine the PIMs in the context of the entire MYRP. Tr. vol. 15, 15. Witness Bateman testified that DEP took a conservative approach in this first PBR Application in order for DEP, customers, and the Commission to gain experience with the operation and implementation of PIMs. *Id.* at 69. DEP witness Stillman explained DEP's approach to designing the PIMs around the 1.0% cap set forth in N.C. Gen. Stat. § 62-133 and stated that DEP was deliberate in choosing to propose only a select number of PIMs that meet the maximum number of policy goals. *Id.* at 65.

Public Staff witnesses D. Williamson and Thomas provided testimony in support of the PIMs Stipulation. Tr. vol. 18, 424-25. Witnesses D. Williamson and Thomas testified that the PIMs Stipulation benefits ratepayers by providing improved compliance with N.C.G.S. § 62-133 and that each PIM in the stipulation appropriately targets a specific policy goal set forth in N.C.G.S. § 62-133. They further testified that the PIMs Stipulation

[5] The NERP was a stakeholder process to examine ways to align utility regulation with the 2019 Clean Energy Plan initiated by Governor Roy Cooper. Tr. vol. 14, 74.

will benefit ratepayers through improved operational efficiencies, cost savings, and reliability of electric service over the course of the MYRP. *Id*.

Power Quality Stipulation

On May 1, 2023, DEP and CIGFUR filed the Power Quality Stipulation. The Power Quality Stipulation provides that DEP and CIGFUR will work together to identify up to 13 industrial customer premises with DEP-owned transmission-to-distribution retail substations exclusively or primarily dedicated to the respective customer (Eligible Premises). Subject to a feasibility review, DEP will install power quality monitoring technology at each of the Eligible Premises and meet with the identified customer at least once annually to review the data from the power quality monitoring technology.

In his testimony supporting the Power Quality Stipulation, CIGFUR witness Nicholas Phillips stated that the stipulation will help ensure that DEP will satisfy the requirement to maintain or improve reliability as North Carolina implements the Carbon Plan. Tr. vol. 21, 495. He testified that the reliability risks posed by inverter-based resources are well-documented and that the Commission has recognized those risks. *Id*. at 496-97.

Witness Phillips explained in his testimony that the power quality pilot program would allow DEP to mitigate the reliability risks associated with inverter-based resources. *Id*. at 497-98. Specifically, he testified that it would allow DEP to: (1) proactively monitor power quality during implementation of the Carbon Plan; (2) gather and share data analytics with the Public Staff and the Commission; (3) determine whether power quality incidents are the result of an individual circuit or customer problem, or potentially part of a larger trend; (4) diagnose potential power quality issues and, pursuant to review, implement solutions to address any such issues; and (5) take a proactive approach to customer service and service quality. *Id.*

Regarding the cost of the pilot program, DEP witness Stillman testified on cross examination that the Power Quality Stipulation does not expressly limit the amount to be spent on the program. Tr. vol. 15, 76. He testified that the cost of installing the power quality monitoring technology would be approximately $10,000 to $25,000 per meter and that the total number of meters necessary for this pilot program is unknown. *Id.* at 75. He further testified that the cost of implementing solutions to any problems identified through the pilot program, as contemplated in the Power Quality Stipulation, will depend on the cause of the specific power quality issue for each premise. He added that the lessons learned from the pilot program will help the whole system, because the more meters that DEP installs, the more DEP will learn about the source of the power quality issues. In acknowledging that DEP intends to seek cost recovery on a cost-of-service basis, witness Stillman testified that the pilot program will help DEP better understand power quality issues, which, ultimately, will be to the benefit of all customers. Tr. vol. 21, 474-76.

Affordability Stipulation

On May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation. The Affordability Stipulation obligates DEP to withdraw the affordability PIM proposed in this proceeding. In lieu of the affordability PIM, $16 million of shareholder funds will be dedicated over the next three years to address affordability concerns as follows: $10 million will be contributed to support health and safety repairs that would allow for energy efficiency and weatherization upgrades to homes; and $6 million will be contributed to the Share the Light Fund, which offers customers bill payment assistance. Tr. vol. 22, 99-100. In addition, the stipulation obligates DEP to collect and report annually, in Docket No. M-100, Sub 179, the monthly payments ratio, which is the number of residential payments remitted divided by the number of active residential accounts. Finally, the stipulation obligates DEP to establish its CAP as a three-year pilot program and convene a stakeholder engagement process to consider CAP data, metrics, and future CAP program features.

MGS Partial Rate Design Stipulation

On May 10, 2023, DEP, the Commercial Group, and Kroger Co. and Harris Teeter filed the MGS Partial Rate Design Stipulation, which resolves some of the issues in this proceeding among the parties. The MGS Partial Rate Design Stipulation provides that 75.0% of any reduction in revenue requirement, as determined by final Commission order, applicable to rate schedule MGS-time-of-use (TOU), should be applied to energy rates. The MGS Partial Rate Design Stipulation also obligates Kroger Co. and Harris Teeter to withdraw their proposal related to a multi-site aggregate commercial rate. Finally, the MGS Partial Rate Design Stipulation provides that Kroger Co. and Harris Teeter do not oppose the Revenue Requirement Stipulation or the PIMs Stipulation.

LGS Partial Rate Design

On June 7, 2023, DEP and CIGFUR filed the LGS Partial Rate Design Stipulation, which provides that any increase in energy charges resulting from any increase in DEP's revenue requirement to be recovered from the LGS, LGS-TOU, and LGS-Real Time Pricing (RTP) rate schedules, as determined by final Commission order, shall be limited to a percentage that is less than half of the approved overall increase percentage to the LGS, LGS-TOU, and LGS-RTP classes, respectively, exclusive of any decrements for the LGS, LGS-TOU, and LGS-RTP rate schedules. By its terms, the LGS Partial Rate Design Stipulation would apply to any customer currently taking service under an LGS, LGS-TOU, or LGS-RTP rate schedule who proceeds to take service under either the High Load Factor tariff or Hourly Pricing (HP) tariff, in the event the Commission approves such tariffs in this proceeding.

Supplemental Revenue Requirement Stipulation

On June 27, 2023, DEP and the Public Staff filed the Supplemental Revenue Requirement Stipulation which resolves issues related to the Public Staff audit of DEP's

third and final update. On that same date the Public Staff filed the joint supplemental testimony of witness Metz, Zhang, and Boswell in support of the stipulation. DEP also filed testimony in support of the stipulation.

Discussion and Conclusions

Because not all parties to this docket have adopted the stipulations outlined above, the standards set out by the North Carolina Supreme Court in *State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc.,* 348 N.C. 452, 500 S.E.2d 693 (1998) (*CUCA I*), and *State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, Inc*., 351 N.C. 223, 524 S.E.2d 10 (200) (*CUCA II*) govern the Commission's acceptance of the stipulations. In *CUCA I,* the Supreme Court held that:

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.

CUCA I, 348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in *CUCA II*, the fact that not all parties have adopted a settlement does not permit the Court to subject the Commission's order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. *CUCA II*, 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation.

> requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] ... satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties.

Id. at 231-32, 524 S.E.2d at 16.

The Commission concludes that the Revenue Requirement Stipulation, the COSS Stipulation, the TCA Stipulation, the PIMs Stipulation, the Power Quality Stipulation, the Affordability Stipulation, the MGS Partial Rate Design Stipulation, the LGS Partial Rate Design Stipulation, and the Supplemental Revenue Requirement Stipulation result from

the give-and-take negotiations between the stipulating parties and represent compromises that are fair and adequate to each party. The Commission has fully evaluated the provisions of these stipulations, the testimony proffered by parties in support of these stipulations cited above, the dearth of evidence in the record opposing any of these stipulations, and concludes, exercising its independent judgment, that it should accept in part and reject in part the provisions of the stipulations, consistent with the specific discussion and resolution of the issues set forth below.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-13

Depreciation

The evidence supporting these findings of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Spanos and Jiggetts, Public Staff witnesses Zhang and Boswell, Lucas, and McCullar, FPWC witness Tomcyzk, and CIGFUR witness Gorman; and the entire record in this proceeding.

Spanos Direct Exhibit 1 to DEP witness Spanos's direct testimony is the 2021 DEP Depreciation Study prepared by Gannett Fleming (2021 Depreciation Study). Tr. Ex. vol. 10. Witness Spanos testified that the purpose of the 2021 Depreciation Study was to estimate the most current annual depreciation accruals related to electric plant in service for ratemaking purposes and to determine appropriate average service lives and net salvage percentages for each plant account. *Id.* at 352-53.

Section III, Paragraphs 2 and 3 of the Revenue Requirement Stipulation provides that DEP's depreciation rates will be set based on the rates in DEP's 2021 Depreciation Study, as adjusted in the stipulation. In conjunction with the use of DEP's proposed accelerated retirement dates for its Mayo and Roxboro Units 3 and 4, the Revenue Requirement Stipulation provides that 75.0% of the increased depreciation expense due to the accelerated retirement dates will be placed in a regulatory asset. *Id.* Section 5 of S.L. 2021-165 permits securitization for 50.0% of the remaining net book value of subcritical coal plants. The Revenue Retirement Stipulation further provides that at retirement, the net book value amounts that are not securitized will be recovered with a return over an amortization period that the Commission will determine in a future rate case. *Id.* In addition, the Revenue Requirement Stipulation sets forth the following specific adjustments to DEP's depreciation rates: (1) the amortization periods Public Staff witness McCullar proposes for General Plant FERC accounts 391 and 397 will be adopted; and (2) the 70-year life for Transmission FERC account 356 witness McCullar proposes will be adopted. *Id.*

Summary of Evidence

Retirement Dates for Coal Plants

DEP witness Spanos testified that life span estimates included in depreciation studies are based on informed judgment, incorporating factors for each facility such as facility technology, management plans and outlook for the facility, and estimates for similar facilities of other utilities. Tr. vol. 10, 358. Witness Spanos testified that he used these factors to evaluate DEP's recommended retirement dates and agreed that they were reasonable. *Id.* at 417. The 2021 Depreciation Study identified the following retirement dates for the Mayo and Roxboro units:

Unit	2021 Depreciation Study Retirement Dates
Mayo 1	December 31, 2028
Roxboro 1	December 31, 2028
Roxboro 2	December 31, 2028
Roxboro 3	December 31, 2027
Roxboro 4	December 31, 2027

As DEP witness Spanos testified, the Mayo and Roxboro lifespans are shorter than those identified in DEP's 2018 Depreciation Study, with Mayo Unit 1 having a change in retirement date from 2029 to 2028 and Roxboro Units 3 and 4 having a change in retirement date from 2029 to 2027. Tr. vol. 10, 359. The 2021 Depreciation Study indicates a life span for Mayo Unit 1 of 45 years, for Roxboro Unit 3 of 54 years, and for Roxboro Unit 4 of 47 years. *Id.* Witness Spanos testified that while the most common range of life spans for steam production facilities had been 55 to 65 years, these originally proposed life spans have been shortened in recent years due to unit efficiencies and environmental regulations. *Id.* He also testified that the industry average of similar units in recent years has been 46 years. *Id.*

In connection with these retirement dates, DEP witness Jiggetts testified that DEP was requesting permission to defer to a regulatory asset 50.0% of the impact of the accelerated depreciation of DEP's coal plants for North Carolina retail customers in order to preserve the ability to recover those costs through securitization as S.L. 2021-165 authorizes. Tr. vol. 13, 208. Jiggetts testified that because the accelerated dates reflected in the 2021 Depreciation Study would reduce the net book value of the plants at retirement and because DEP wants customers to benefit from any savings that securitization could provide, upon retirement of the facilities DEP proposes to defer to a regulatory asset 50.0% of the remaining net book value. *Id.* Witness Jiggetts testified that this approach preserves for securitization the level of net book value that would have resulted had the expected retirement dates not been updated in the 2021 Depreciation Study. *Id.* DEP also seeks permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement. *Id.* at 208-09.

Public Staff witnesses Lucas and McCullar both addressed the coal plant retirements and life spans in their testimony. In his direct testimony, witness Lucas

recommended the use of the retirement dates DEP provided in its 2014 and 2016 Integrated Resource Plans filed in Docket Nos. E-100, Sub 141 and 147, respectively. Tr. vol. 20, 38.

Witness Lucas testified that his recommended retirement dates differ solely for calculating rates in the rate case, not for planning purposes. *Id.* He does not dispute the physical retirement dates that the Commission's Carbon Plan Order established, rather, he testified that issues of reliability and cost inform his recommendations. *Id.* at 38-39; Order Adopting Initial Carbon Plan and Providing Direction for Future Planning (Carbon Plan Order), *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan*, No. E-100, Sub 179 (Dec. 30, 2022). Witness Lucas testified that if DEP can accelerate depreciation before retirement, customers will not only pay more in the near-term but also that the plants will have less value to securitize in the long-term, thereby muting the benefit of securitization to ratepayers. *Id.* at 39. He testified that because Session Law 2021-165 and Commission Rule R8-74 allow securitization of remaining plant value, the financial benefit of potentially delaying the retirement of either Mayo or Roxboro should not accrue solely to DEP. *Id.*

Witness Lucas further testified that DEP has a plan to replace Roxboro's capacity with hydrogen-enabled combustion turbines and combined-cycle capacity, but it has not fully developed this plan. *Id.* He also testified that DEP has not indicated its plans for replacing general capacity for the Mayo plant. *Id.* Witness Lucas stated that if DEP retires either Mayo or Roxboro before its recommended date, DEP should securitize 50.0% or more of the remaining book value while continuing to depreciate any amount not securitized. *Id.*

Witness McCullar proposed depreciation rates based on the final retirement years provided by witness Lucas. Tr. vol. 21, 138.

FPWC witness Tomcyzk recommended final retirement dates for certain coal units that are later than dates proposed by DEP and recommended that the Commission reject DEP's request to defer 50.0% of the incremental increase in the depreciation expense because implementation of FPWC's revised retirement dates renders the deferral unnecessary. Tr. vol. 21, 729, 734. FPWC's recommended retirement dates would make DEP's request to defer 50.0% of the incremental depreciation unnecessary. *Id.* Witness Tomcyzk stated that, should the Commission approve DEP's retirement dates or otherwise accelerate retirement, then all of the resulting incremental depreciation expenses should be deferred to a regulatory asset. *Id.* at 734-35.

CIGFUR witness Gorman recommended that the Commission reject DEP's proposal to recover the 50.0% of non-deferred accelerated depreciation expenses associated with Mayo Unit 1 and Roxboro Units 3 and 4 through its base rates. Tr. vol. 21, 436. Witness Gorman testified that accelerating the retirement of these units may not be feasible and recommended that the Commission not allow DEP to include costs for such early retirement in its cost of service. *Id.* at 434.

In rebuttal, DEP witness Spanos testified that the retirement dates for the Mayo and Roxboro plants are consistent with informed judgment based on each unit and the expectation within the industry. Tr. vol. 10, 358-59. He testified that many other coal plants either have been or are planned to be retired with lifespans of around 40-45 years and that the proposed lifespans of DEP's plants are consistent with those of other utilities. Tr. vol. 10, 373. DEP witness Jiggetts testified that the retirement dates Public Staff witness Lucas proposed are from DEP's 2013 Depreciation Study and that it is inappropriate to use dates from a 2013 Depreciation Study that is almost 10 years old. Tr. vol. 23, 91. Further, in response to Public Staff witness Lucas' recommendation that DEP securitize 50.0% or more of the remaining book value while continuing to depreciate any amount not securitized, DEP witness Jiggetts responded that S.L. 2021-165 only permits securitization for 50.0% of the remaining net book value for subcritical coal plants and, therefore, that it is only appropriate to apply this proposed ratemaking treatment to 50.0% of the plant balances. *Id.*

In response to Public Staff witness Lucas' proposal to change coal plant retirement dates "for ratemaking purposes only," DEP witness Jiggetts testified that DEP is aligned with this proposal in principle, but not in methodology. *Id.* at 90. DEP witness Jiggetts testified that the depreciation rates should be set based on the actual planned retirement dates, and then deferrals and regulatory assets should be used for jurisdictionally specific ratemaking purposes. *Id.* Witness Jiggetts testified that the methodology is particularly important because securitization of the coal plant balances is only available for DEP's North Carolina retail jurisdiction and, therefore, the more appropriate way to accomplish the result that Public Staff witness Lucas supports is to use deferral and regulatory assets. *Id.* at 91.

Amortization Periods for General Plant FERC Accounts 391 and 397

Public Staff witness McCullar and FPWC witness Tomczyk both object to DEP's proposal to change the amortization period for General Plant FERC account 391, Office Furniture and Equipment, from 20 years to 15 years, and to change the amortization period for General Plant FERC account 397, Communication Equipment, from 20 years to 10 years. Tr. vol. 21, 142, 754. Both witnesses recommend the continued use of the currently approved 20-year amortization period for these accounts. *Id.* Public Staff witness McCullar noted that the Commission previously approved the continued use of 20-year amortization periods for accounts 391 and 397 in the 2019 Rate Case. Witness McCullar stated that DEP is proposing the same amortization periods for these accounts that it initially proposed in the 2019 Rate Case and others. She further stated that the 2021 Depreciation Study in this case did not provide any life data for either account. Tr. vol. 21, 142-43.

In response, DEP witness Spanos notes that the amortization period for these accounts are approved for DEC, and asserted that it is reasonable to use the same amortization periods currently approved for DEC, as those periods are more representative of the appropriate useful life. Tr. vol. 10, 397. He further testified that witness Tomczyk's rationale supporting her proposal to maintain the periods approved in

a prior case is insufficient and that an amortization period should reflect the most reasonable useful life of the actual assets in each account. *Id.*

70-year life for Transmission FERC Account 356

For Transmission FERC account 356, Overhead Conductors and Devices, DEP proposes a 65-year estimated average service life with an R2.5 survivor curve. In contrast, Public Staff witness McCullar proposes a 70-year estimated average service life. Witness McCullar argued that the Public Staff's proposal is mathematically a better fit to the actual data and that her estimate included a review of historic observed life data provided in the 2021 Depreciation Study, the relevant information DEP provided in response to discovery, and her previous experience. *Id.* at 147-48.

In response, DEP witness Spanos testified that the witnesses have taken different approaches in interpreting the relevant data, and that he disagrees with these approaches. Tr. vol. 10, 382. FPWC witness Tomczyk and Public Staff witness McCullar both stated that they considered other factors in the development of their life estimates, but they appear to support their estimates primarily with mathematical fitting results, which is one, but not the only, factor to consider when developing a life estimate. *Id.* at 386. DEP witness Spanos argued that the life estimates witnesses Tomczyk and McCullar propose omit any consideration of changes to the transmission system resulting from impacts of DEP's evolving generation fleet, produce overall life cycles that are longer than what is reflected in the historical data, and serve only to lengthen the proposed life of the assets and reduce depreciation expense. *Id.* Additionally, DEP witness Spanos testified that their estimates reflect an expectation that too high a percentage of the overhead conductors will remain reliable.

Other Depreciation Recommendations

Other Production FERC Account 343 and Transmission FERC Account 352 – Survivor Curves

FPWC witness Tomczyk recommends adjustments to the survivor curve applied to Other Production FERC account 343, Prime Movers, and Transmission FERC account 352, Structures and Improvements.

For Other Production FERC account 343 FPWC witness Tomczyk recommends the use of the L0-35 survivor curve, as opposed to the L0-30 survivor curve DEP witness Spanos proposes. Tr. vol. 21, 739. Witness Tomczyk testified that DEP did not provide a reason either in its 2021 Depreciation Study or in DEP witness Spanos' direct testimony as to why the actuarial data for this account was truncated at 39.5 years in the original and smooth survivor curve graphs in the 2021 Depreciation Study. When selecting her recommended survivor curve, witness Tomczyk testified that she considered the sum of the squared deviations (SSDs) for both truncated and full curves to be important. *Id.* at 741. Additionally, she considered the survivor curves other electric utilities use for this account and relied on her professional judgment. Based on her experience, the survivor curves other comparable utilities use typically have associated service lives that exceed

those that DEP recommends in this case. *Id.* at 741-42. FPWC witness Tomczyk noted that the only supporting information DEP provided for its survivor curve for this account is that its statistical analyses resulted in "good to excellent indications" of the survivor patterns experience for this account. *Id.* at 742.

For Transmission FERC account 352, FPWC witness Tomczyk recommends the use of an R2.5-70 survivor curve, while DEP recommends an R2.5-65 survivor curve. She testified that, in response to data requests, DEP noted that it truncated actuarial data for this account at 56.5 years in the original and smooth survivor curve graph because assets exposed to retirement above 56.5 years are less significant when compared to the total assets exposed to retirement. Additionally, the retirement activity occurring at ages in excess of 56.5 years is not typical of retirement activity for assets of those ages. Witness Tomczyk generally noted that her proposed survivor curves had lower SSDs when not truncated. Additionally, she noted that FPWC requested, but DEP did not provide, any information that explained the rationale for DEP's recommended survivor curve. As with account 343, the only information DEP provided indicated that their statistical analyses resulted in what DEP characterized as "good to excellent indications" of the survivor patterns experienced for this account.

In rebuttal, DEP witness Spanos stated that the primary reason for differences between his estimates and FPWC's estimates for survivor curves is that the parties interpreted the data differently. For Other Production FERC account 343, he argued that FPWC witness Tomczyk appears to base her proposed estimate solely on "mathematical curve matching," whereas he used a method of "visual curve matching." He also stated that FPWC witness Tomczyk's proposed survivor curve for account 343 appears to ignore the most significant portion of the historical data, and instead focuses on assets that have been in service for 35 years or more. These assets represent less than half of the assets exposed to retirement during the overall band of experience and are ones that are less indicative of asset lives into the future. Witness Spanos testified that this is inappropriate when considering an interim survivor curve and that the narrow mathematical curve matching approach is not reasonable. In regard to Transmission FERC account 352, witness Spanos testified that a review of witness Tomczyk's mathematical approach for this account shows that she was focusing her proposed, elongated survivor curve on a period reflecting nominal retirement experience and that this is not consistent with the future expectations of retirement activity in this account. Tr. vol. 10, 391. Witness Spanos explained during his cross-examination that the job of an analyst doing life estimation is not to match what has happened in the past, but rather to predict what is happening going forward. *Id.* at 462-63. Witness Spanos testified that a focus on mathematical matching can only match what has occurred in the past, which is only a part of the necessary overall analysis. *Id.* at 463.

Transmission FERC Account 353 – Net Salvage Rate

FPWC witness Tomczyk recommends that the Commission use a net salvage rate of negative 10.0%, as opposed to DEP's proposed net salvage rate of negative 15.0%. Tr. vol. 21, 750. In support of this recommendation, she noted that for the period 1979

through 2021, net salvage averaged 9.0% and that the most recent five-year average is negative 10.0%. *Id.* She also noted that, after reviewing net salvage statistics, the swings in the more recent three-year moving averages for account 353 were much less significant than for most other transmission accounts. *Id.* at 751. She testified that, based on her recent experience, net salvage rates for account 353 most often are in the negative 10.0% to negative 15.0% range. *Id.*

In rebuttal, DEP witness Spanos testified that, although the numbers FPWC witness Tomczyk cited from the 2021 Depreciation Study are correct, she ignored the fact that two of the last five years (2019 and 2021) reflect very low, anomalous cost of removal activity, which DEP should consider when developing a net salvage estimate. Tr. vol. 10, 391. During recent years, annual retirements have been increasing. *Id.* However, in 2019 and 2021, the recorded cost of removal was extremely low related to the retirements. *Id.* Given this nominal cost of removal activity in 2019 and 2021, DEP gave these years less weight than prior years. *Id.* at 391-92. Therefore, given the lag in recording cost of removal to the associated retirements and the increase in the industry for removal cost for substation equipment, witness Spanos argued that the negative 15.0% net salvage estimate is a more reasonable representation of net salvage for future retirements. *Id.* at 392.

Revenue Requirement Stipulation

Sections III, Paragraphs 2 and 3 of the Revenue Requirement Stipulation provide that DEP's depreciation rates will be set based on the rates in the 2021 Depreciation Study as adjusted in the stipulation. In conjunction with use of DEP's proposed accelerated retirement dates for its Mayo and Roxboro Units 3 and 4, the Revenue Requirement Stipulation provides that the 75.0% of the increased depreciation expense due to the accelerated retirement dates will be placed in a regulatory asset. *Id.* S.L. 2021-165 permits the securitization for 50.0% of the remaining net book value for subcritical coal plants. The Revenue Retirement Stipulation further provides that at retirement the net book value amounts that are not securitized will be recovered with a return over an amortization period that the Commission will determine in a future rate case. *Id.* The Revenue Requirement Stipulation sets forth the following specific adjustments to DEP's depreciation rates: (1) the amortization periods proposed by Public Staff witness McCullar for General Plant FERC accounts 391 and 397 will be adopted; and (2) the 70-year life for Transmission FERC account 356 proposed by witness McCullar will be adopted. *Id.*

Discussion and Conclusions

Retirement Dates for Coal Plants

Based on the Revenue Requirement Stipulation and the entire record in this proceeding, the Commission concludes that it is appropriate to depreciate Mayo Unit 1 and Roxboro Units 1-4 based on the accelerated retirement dates proposed by DEP. Section III, Paragraph 2 of the Revenue Requirement Stipulation provides that DEP's proposed retirement dates for its coal plants will be used to set depreciation rates. Witness Spanos testified that he performed a thorough analysis of the life spans for Mayo

Unit 1 and Roxboro Units 1-4 using accepted depreciation methods. His analysis specifically considered factors for each facility such as facility technology, management plans and outlook for the facility, and the estimates for similar facilities for other utilities. As witness Spanos testified on cross-examination, he made site visits, had discussions with operational personnel at each plant site, and took the necessary steps to understand the expectations for the assets and how things may change functionally for various reasons. Tr. vol. 10, 405. Witness Spanos has reviewed DEP's facilities in developing his depreciation studies over numerous years and has a great deal of experience with the specific facilities at issue in this proceeding, as well as steam plants across the country. Furthermore, the life spans DEP proposes for Mayo and Roxboro are consistent with the 45-to-50-year life spans that are occurring across the industry as more utilities transition away from coal burning generation facilities.

The Commission is not persuaded by FPWC witness Tomczyk's assertion regarding the level of uncertainty regarding the retirement dates of Mayo and Roxboro. The Commission notes that the asset retirement dates are established by the Commission in the integrated resource planning process and the retirement dates for Mayo Unit 1 and Roxboro Units 1-4 were addressed in the Carbon Plan Order. The Commission determines that the agreement encapsulated in the Revenue Requirement Stipulation, which addresses DEP's plans for Mayo Unit 1 and Roxboro Units 1-4 using the accelerated retirement dates while also accomplishing the type of rate mitigation that witness Lucas proposed strikes a reasonable balance. The Commission further determines that the provision in the Revenue Requirement Stipulation to increase the proposed deferral to a regulatory asset from 50.0% to 75.0% of the incremental depreciation expense that results from the accelerated retirement is reasonable and appropriate. As provided under the Revenue Requirement Stipulation, DEP will recover 50.0% of net book value through securitization and will recover the remaining amount, with a return, over an amortization period to be determined in a future rate case.

Amortization Periods for Plant FERC Accounts 391 and 397, and 70-year life for Transmission FERC Account 356

Based upon the evidence Public Staff witness McCullar presented, the Commission finds that the settled-upon amortization periods for General Plant FERC accounts 391 and 397 and the 70-year life for Transmission FERC account 356, as outlined in the Revenue Requirement Stipulation, are just and reasonable and appropriate for use in this case.

Other Production FERC Account 343 and Plant FERC Account 352 – Survivor Curves

Based on the entirety of the record the Commission concludes that the survivor curves proposed by DEP in this proceeding are just and reasonable and appropriate for use in this case.

Transmission FERC Account 353 – Net Salvage Rate

Based on all the evidence presented, the Commission concludes that it should not adopt FPWC witness Tomczyk's Transmission FERC account 353 proposal. In particular, the facts that annual retirements have been increasing in recent years, and that DEP reduced the weight afforded to removal activity in 2019 and 2021, weigh in favor of DEP's proposed net salvage rate. Accordingly, the Commission concludes that the proposed net salvage rate of negative 15.0% is just and reasonable and appropriate for use in this case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

Base Period Plant-Related Items

The evidence supporting this finding of fact appears in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Turner, Jiggetts, Guyton, Maley, and Ray, and Public Staff witnesses Metz, Thomas, Michna, and T. Williamson, the joint settlement testimony of Public Staff witnesses Metz and McLawhorn, and the joint testimony of Public Staff witnesses Boswell and Zhang; the Revenue Requirement Stipulation; and the entire record in this proceeding.

Summary of Evidence

Generation Capital Investments

DEP witness Turner described DEP's traditional/renewable/storage generation fleet and the operational performance of those assets during the test year. Tr. vol. 12, 91. Witness Turner testified as to the major capital projects undertaken by DEP for maintenance of its fossil, renewable, and storage fleets. *Id*. at 96. In testifying on the importance of the traditional fossil fleet to customers in North Carolina, she explained that the diversity of the resource and fuel mix, and availability of coal generation during the transition away from coal, must be strategically managed to ensure the remaining coal fleet can reliably contribute to resource adequacy. She testified that as DEP makes plans to retire its remaining coal fired assets, and replace those assets with other resources, DEP must keep these remaining units in efficient working order to support the energy needs of its customers. She explained that DEP will continue to make investment in these assets to ensure that the same reliable cost effective electricity that customers have counted on for decades remains available while the replacement of those units is developed and implemented. Additionally, she testified that the combination of generation resources that replaces coal must be able to provide the same level of reliability that the coal units have provided and that because natural gas is critical to the resource mix – particularly during the winter months and while energy storage capacity is being developed and deployed – DEP will continue to rely on its natural gas fleet as part of the diverse and dispatchable resource mix to ensure the reliability of service to DEP customers. Tr. vol. 12, 91-95. Witness Turner also testified regarding DEP's hydro fleet capital maintenance projects, which were undertaken primarily for regulatory compliance. She further testified as to DEP's addition of three battery installations, including the

Asheville/ Rockhill storage project, the Hot Springs Microgrid, and the Camp Lejeune project. *Id.* at 96-97. Finally, she testified as to her opinion that DEP has reasonably and prudently operated its fossil/hydro/solar fleet during the test period. *Id.* at 99-101.

DEP witness Ray described DEP's nuclear generation assets and capital additions made to the fleet since the 2019 Rate Case to enhance safety and efficiency preserve performance and reliability of the plants throughout their extended life operations, and address regulatory requirements. Tr. vol. 16, 154. Witness Ray described how these capital additions are or would be by the capital cutoff date used and useful in safely and efficiently providing reliable electric service to DEP's customers. Tr. vol. 16, 152-62. He testified about the exceptional performance of the nuclear fleet during the test period and initiatives that DEP has undertaken to increase nuclear operational efficiency. *Id.* at 168-70. He testified that, in comparison to others in the industry, DEP's nuclear fleet has a history of top performance, including a test period capacity factor of 94.94%, which exceeds the average capacity factor for comparable units published in the most recent North American Electric Reliability Council's (NERC) Generating Unit Statistical Brochure. *Id.* at 70.

Public Staff witnesses Metz, Thomas, and Michna reviewed aspects of DEP's capital investments in its traditional/renewable/storage generation fleet. Public Staff witness Metz described his review of DEP's historic costs associated with projects placed in service for the period June 2020 through November 2022, noting that his investigation included multiple site visits to DEP's fleet of generating stations and to an operations center, as well as numerous meetings with DEP personnel. Tr. vol. 16, 412. Witness Metz did not propose any adjustments to the base case capital investment costs for the fossil/hydro or nuclear fleets. Public Staff witness Thomas reviewed DEP's capital additions to solar, storage and hydro plant since the 2019 Rate Case and recommended an adjustment regarding the Blewett Falls Fishing Pier and the Hot Springs Microgrid. Tr. vol. 19, 172. Public Staff witness Michna reviewed DEP's capital additions for steam generation since the 2019 Rate Case and recommended an adjustment to the aqueous ammonia conversion project at Mayo Station (Mayo Ammonia Conversion Project). Tr. vol. 21, 285.

Blewett Falls Fishing Pier

Public Staff witness Thomas recommended that DEP remove the Blewett Falls fishing pier from the base case and include it in the MYRP Rate Year 1 based on his conclusion that, although DEP asserted that it placed the fishing pier in service in 2021, it is not yet complete or open for public use and will remain closed for safety reasons. Tr. vol. 19, 208-09.

DEP witness Turner testified that DEP placed the pier in service pursuant to DEP's capital accounting guidelines in January 2021, but that it is not currently open for public access due to ongoing construction of a fish passage facility directly next to the pier. Witness Turner asserts that public accessibility does not determine whether an asset is in service, and that Public Staff witness Thomas did not meaningfully challenge DEP's application of the accounting guidelines, which govern the in-service determination. Tr. vol. 12, 141.

In the Revenue Requirement Stipulation, DEP accepted the Public Staff's recommendation to move the fishing pier project and its associated costs out of the base case and into the MYRP Rate Year 1. Revenue Requirement Stipulation § II.33.a, Tr. Ex. vol. 7. DEP witnesses Abernathy and Jiggetts and Public Staff witnesses McLawhorn and Metz supported this provision in their settlement supporting testimony. Tr. vol. 13, 138-40, 254-55, 262; Tr. vol. 16, 514.

Mayo Ammonia Conversion Project

Public Staff witness Michna recommended an adjustment to remove $3,230,371 in costs for the Mayo Ammonia Conversion Project. Witness Michna recommended the adjustment based on his conclusion that DEP's decision to not update the cost benefit analysis for the project after significant delays to account for significant changes in cost and the projected station retirement date was not prudent. Tr. vol. 21, 295-97.

DEP witness Turner testified that DEP's development and execution of the project has been reasonable and prudent, emphasizing that the driving factor for the project was elimination of the safety risk to plant personnel that the existing ammonia system presents. Tr. vol. 12, 139-40.

As part of the Revenue Requirement Stipulation, DEP accepted the Public Staff's proposed adjustment related to the Mayo Ammonia Conversion Project. Revenue Requirement Stipulation § III.10, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn and Metz supported this provision in their settlement supporting testimony. Tr. vol. 13, 254-55, 263; Tr. vol. 16, 514.

Hot Springs Microgrid

Public Staff witness Thomas recommends that the solar costs associated with the Hot Springs Microgrid be allocated 100.0% to the "Other Production Plant" account as opposed to DEP's proposed allocation of 50.0% to "Distribution Plant" and 50.0% to "Other Production Plant." Tr. vol. 19, 192. DEP accepted this recommendation in rebuttal testimony and agreed to make the corresponding accounting adjustment. Tr. vol. 11, 47. The Revenue Requirement Stipulation reflects this adjustment.

Transmission and Distribution Base Period Investments – Non-Grid Improvement Plan (GIP)

In their direct testimonies, DEP witnesses Guyton and Maley discussed DEP's distribution and transmission investments since its last general rate case. DEP Witness Guyton testified that DEP had invested approximately $814 million in new distribution infrastructure since DEP's last rate case, which included investments in DEP's GIP. Witness Guyton testified that non-GIP distribution investments during the base period included targeted reliability and maintenance programs, and customer driven line and substation expansions. Tr. vol. 10, 38. In his direct testimony, witness Maley testified that DEP had spent

approximately $390 million in additional transmission infrastructure since its last rate case, the bulk of which was for reliability and capacity improvements. Tr. vol. 10, 169-70.

In their direct testimonies, Public Staff witnesses Metz and T. Williamson took issue with some of the transmission and distribution capital investments made by DEP since its last case, as discussed in more detail below. Specifically, witness Metz took issue with the inclusion in rate base of capital associated with a newly refurbished transmission service building project (Project Florence), as well as the timing of inclusion in rate base of investments in a new Electric Systems Operation center (Project Walter). In addition, in his direct testimony, witness T. Williamson recommended a $712,867 disallowance for costs associated with contractor damage to a Wilmington voltage regulator platform.

Project Florence and Project Walter

Public Staff witness Metz described DEP's Project Florence to support maintenance and construction for transmission service projects in Florence, South Carolina. Project Florence included demolishing facilities at DEP's existing site to build a new consolidated single building to serve DEP's Carolinas East Southern Region. Tr. vol. 16, 416-18. In his direct testimony, Public Staff witness Metz recommended removal of the costs for Project Florence due to insufficient information from DEP to justify the project. *Id.* at 420.

Witness Metz also described DEP's Project Walter, a new energy control/operations center to operate DEP's bulk electric system and manage DEP's distribution system. Tr. vol. 16, 424. Based on his review of when the project would begin to serve its intended purpose, witness Metz recommended that DEP include the project in Rate Year 1 of the MYRP rather than in the base period. *Id.*

On rebuttal, DEP witness Guyton testified that Project Florence was prudent, and that the refurbishment of facilities was necessary to efficiently meet increased and growing demand on the transmission operations center in terms of personnel and equipment and that the pre-existing buildings were no longer sufficient to meet DEP's need. Tr. vol. 10, 139-40. On rebuttal, witness Guyton also asserted that Project Florence is currently used and useful as evidenced by the fact that construction is complete, local authorities have issued certificates of occupancy, and the building is in active use for certain functionalities, with the remaining functionalities to be working out of the building before rates are in effect in this proceeding. Tr. vol. 10, 135.

Section III, Paragraph 9 of the Revenue Requirement Stipulation provides that the Project Florence costs shall be included in rate base and the costs of Project Walter shall be moved into Rate Year 1 of the MYRP as recommended by Public Staff witness Metz.

Wilmington Voltage Regulator Platform

Public Staff witness T. Williamson described the Wilmington Voltage Regulator Platform project, which DEP undertook in order to provide additional clearance below the regulator platform DEP uses in its Distribution System Demand Response (DSDR)

project. Tr. vol. 21, 203-04. Witness T. Williamson recommends an adjustment due to equipment damage a contractor caused during this project. *Id.* at 205. In his rebuttal testimony, DEP witness Guyton challenged the amount of the Public Staff's disallowance for the Wilmington voltage regulator platform incident, on the grounds that witness T. Williamson did not allege that DEP had been negligent or responsible in any way for the contractor damage. Witness Guyton also asserted that any adjustment should only be for the incremental cost of the contractor damage ($267,282), rather than the entire cost of the project. Tr. vol. 10, 140.

Section III, Paragraph 7 of the Revenue Requirement Stipulation reduces the Wilmington voltage regulator costs as Public Staff witness Williamson recommended but with the further adjustment witness Guyton suggested in his rebuttal testimony.

Discussion and Conclusions

Based on the entire record in this proceeding, the Commission concludes that the costs related to DEP's investments in its fossil, renewable, storage, and nuclear fleet assets as well as its transmission and distribution investments made during the test period, as adjusted by the Revenue Requirement Stipulation, were reasonably and prudently incurred and should be recovered. The Commission further concludes that the adjustments for the Blewett Falls Fishing Pier, the Mayo Ammonia Conversion Project, and the Hot Springs Microgrid as the Public Staff and DEP agreed in the Revenue Requirement Stipulation are reasonable. Finally, the Commission concludes that the adjustments related to Project Walter, Project Florence, and the Wilmington Voltage Regulator Platform project, as included in the Revenue Requirement Stipulation are reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-17

Grid Improvement Plan Cost Recovery

The evidence supporting these findings of fact is included in the testimony and exhibits of DEP witnesses Guyton, Maley, and Jiggetts, Public Staff witnesses Zhang and Boswell, the Revenue Requirement Stipulation, and the entire record in this proceeding.

Summary of Evidence

DEP witness Maley testified that DEP's GIP is enabling new grid capabilities and that the System Intelligence program has begun deployment of dynamic, smart devices with the ability to remotely locate, sectionalize, and assess damage. Tr. vol. 10, 179. Witness Maley testified that the deployment of remote monitoring and control devices with digital relays supports rapid response to system outages and disturbances to quickly restore power to the maximum number of customers and to enable better management of distributed energy resources. *Id.* DEP installed approximately 350 relays and 9 remotely capable switches over the 19 months immediately preceding the date on which DEP filed the Application. In the period starting June 1, 2020, through December 31, 2021, DEP made North Carolina GIP transmission investments totaling $9.2 million. *Id.* at 179-80. Witness Maley testified that DEP

was on track to complete North Carolina GIP work scope in its three-year plan by December 31, 2022. *Id.* at 181.

DEP witness Guyton testified that DEP developed its GIP to build grid capabilities needed to address the implications of seven megatrends. These megatrends represent key trends that drive the need to prepare the grid to safely and efficiently distribute the energy which customers depend on in their daily lives. *Id.* at 56. Witness Guyton also testified about the operational benefits associated with the GIP work that DEP had completed as of the filing of the Application. He testified that the GIP projects, which reduce the frequency and impact of outages, are contributing to the improving trends for the System Average Interruption Index (SAIFI) and the System Average Interruption Duration Index (SAIDI). *Id.* at 50. He testified that, as an example, the Self Optimizing Grid program redesigns key portions of the distribution system, transforming it into a dynamic, smart-thinking grid that can automatically reroute power around trouble areas so that power can be quickly restored to the maximum number of customers and line crews can directly and rapidly be dispatched to the source of the outage. *Id.*

He testified that the GIP distribution investments and the North Carolina retail allocated portion of general and intangible plant investments through the December 31, 2021, test period totaled $52.6 million. *Id.* at 54.

DEP witness Jiggetts testified that in the 2019 Rate Case the Commission approved deferral of certain GIP-related costs for projects placed in service through December 31, 2022, until the costs could be considered for recovery in DEP's next general rate proceeding. Tr. vol. 13, 194-95. With respect to the specific costs that have been deferred, DEP witness Maley testified that DEP has deferred incremental O&M expenses, depreciation, and property taxes associated with the GIP, as well as the carrying cost on the investments and the deferred costs at DEP's weighted average cost of capital. Tr. vol. 10, 182. In her initial direct testimony DEP witness Jiggetts testified that by of the end of 2022, DEP will have placed in service investments of approximately $236.7 million on a North Carolina retail basis. She explained that DEP proposes to amortize the GIP regulatory asset of $38.8 million over a three-year period, which results in an amortization expense of $12.9 million. Tr. vol. 13, 195. In supplemental testimony, DEP witness Jiggetts updated the GIP-related costs to replace estimated data with actual amounts incurred through December 31, 2022, and to reflect a change in the capital cutoff date to March 31, 2023. [6] *Id.* at 224. Witness Maley testified that DEP proposes to roll these costs into base rates in the current rate case. Tr. vol. 10, 182.

While the Public Staff agreed with DEP's assertion that the Commission approved deferral accounting treatment for the GIP programs, the Public Staff took issue with DEP's calculation of the GIP deferral balance. Tr. vol. 19, 59-63. Specifically, Public Staff

[6] The total GIP investment made by DEP as of December 31, 2022, on a North Carolina retail basis is approximately $197 million as shown in the December 2022 NC GIP Biannual Report filed on March 1, 2023 in Docket Nos. E-7, Sub 1214B and E-2, Sub 1219B and Jiggetts Partial Settlement Exhibit 4.

witnesses Zhang and Boswell testified that DEP's inclusion of O&M expenses are outside of the allowable expenses envisioned by the Commission's approval in the 2019 Rate Case. Tr. vol. 19, 62-63. The Public Staff argued that the GIP deferral approved in the 2019 Rate Case is restricted to incremental expenses net of operating benefits. Therefore, the deferral does not include overhead or administrative and general costs but may include a reasonable allocation of management and supervision costs. *Id.* The Public Staff asserted that some of the O&M expenses included in the deferral were not incremental, that DEP had not determined the amount of any operating benefits, and that the O&M expenses included overhead and administrative and general costs. *Id.* As explained by DEP witness Jiggetts, the Public Staff proposed the following adjustments related to DEP's proposed recovery of the deferred GIP costs: 1) removal of $6 million in system O&M costs based on the contentions that DEP did not provide support for amounts after March 2022 and that certain of the costs did not meet the criteria for deferral based on 2019 Rate Case; and 2) an amortization period of 30 years.

DEP witness Guyton testified on rebuttal that the labor expense deferred for GIP projects was incremental to base labor included in rates since DEP had already reduced the deferral by the amount of installation O&M included in current rates. He asserted that the Public Staff's adjustment to remove O&M for GIP O&M-only projects is not reasonable, on the basis that incremental installation is correctly accounted for as O&M. Tr. vol. 10, 141. He also disputed the Public Staff's position on administrative and general costs and testified that such costs were appropriately included in allocation pools that are added to capital projects in accordance with DEP's accounting practices and cost allocation manual. *Id.* at 142. DEP witness Jiggetts also testified on rebuttal as to DEP's disagreement with the Public Staff's adjustment to remove O&M expenses, with the contention that certain expenses were not appropriately allocated to the GIP projects, and with the contention that 30 years is the appropriate amortization period. Tr. vol. 23, 67-70.

Section III, Paragraph 11 of the Revenue Requirement Stipulation provides that DEP is permitted to recover the full balance of its Grid Improvement Deferral over an 18-year amortization period, with a debt-only return during the deferral period and rate base treatment during the 18-year amortization period. No intervenor took issue with this provision of the stipulation. The costs associated with the GIP deferral, as settled upon by the Public Staff and DEP, results in a deferred balance on September 30, 2023, of $22.364 million, and annual amortization expense of $1.242 million, as set forth in DEP witness Jiggetts Partial Settlement Exhibit 4. Tr. Ex. vol. 14.

Discussion and Conclusions

The Commission concludes that the evidence presented supports the treatment of the deferred GIP-related costs as agreed to by DEP and the Public Staff in the Revenue Requirement Stipulation and that the treatment strikes a just and reasonable balance between recovery of costs and mitigation of impacts to customers and, thus, should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-19

Coal Ash

The evidence supporting these findings of fact is included in the Coal Combustion Residuals Settlement Agreement approved in the Commission's Order in the 2019 Rate Case, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, *Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1219 (Apr. 16, 2021) (CCR Settlement); DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Jiggetts and Hill, Public Staff witnesses Zhang and Boswell and Lucas, CIGFUR witness Gorman; and the entire record in this proceeding.

DEP witness Hill provided testimony as to DEP's activities to close ash basins and landfills along with other CCR management units for the period since DEP's last rate case. Tr. vol. 16, 86. Witness Hill testified that the actual and forecasted activities, as well as costs incurred, were reasonable and prudent. *Id.* Moreover, he testified that DEP implemented its plans in accordance with closure and corrective action plans that have been approved by the relevant state environmental agencies – in North Carolina, the Department of Environmental Quality, and in South Carolina, the Department of Health and Environmental Control. *Id.* He testified that DEP has also complied with its obligations under the CCR Settlement. DEP witness Jiggetts presented DEP's request to amortize deferred costs associated with the CCRs and to continue deferring costs related to compliance with coal ash regulations. Tr. vol. 13, 163. Witness Jiggetts testified as to the key components of the CCR Settlement and the associated adjustments made in this case to comply with the CCR Settlement, including the use of proceeds from insurance claims to offset CCR compliance costs. *Id.* at 191. She explained that the CCR costs sought for recovery are based upon actual costs incurred from March 1, 2020 through December 31, 2022, and updated amounts through March 31, 2023, provided in the supplemental filing made on April 18, 2023. *Id.*; Tr. vol. 23, 63. She testified that the cost, less the adjustments, totals approximately $647.8 million on a system basis and $399.3 million on a North Carolina retail basis. *Id.* She testified that DEP's adjustment amortizes the net deferred balance over a five-year period. *Id.* Witness Jiggetts also testified that DEP proposes to offset the over-amortization for the CCR costs established in the 2017 Rate Case in the amount of $8.5 million against the Coal Ash CCR ARO deferral DEP sought recovery of in this case. Witness Jiggetts testified that the balance sought for recovery in this case is being offset by North Carolina retail customer's share of insurance proceeds, calculated in accordance with the CCR Settlement terms, of $80.7 million. *Id.* at 193.

Public Staff witness Lucas investigated DEP's management of CCRs, construction and operation of DEP's CCR beneficiation projects, and proceeds from DEP's litigation of CCR insurance claims. Tr. vol. 20,15. After performing a thorough review, witness Lucas concluded that DEP's CCR management practices have been sufficient to prevent unnecessary costs to its customers, that DEP has complied with the coal ash beneficiation statute and the Commission's requirements, and that DEP's construction and operation of its two beneficiation projects since the last rate case have been sufficient to prevent unnecessary costs to customers. *Id.* at 20-25. Finally, witness Lucas found that DEP

properly credited North Carolina retail customers with proceeds from the insurance litigation. *Id.* at 26.

Public Staff witnesses Zhang and Boswell recommended that the Commission return all expiring amortizations to customers as a single rider over a period of one year with interest. Tr. vol. 19, 73.

CIGFUR witness Gorman recommended two revenue requirement adjustments to DEP's recovery of CCR compliance costs. Tr. vol. 21, 438-39.

The adjustments recommended by the Public Staff and CIGFUR regarding CCR costs were resolved in the Revenue Requirement Stipulation. While the Revenue Requirement Stipulation did not specifically address the CCR cost adjustments recommended by CIGFUR or the Public Staff, Section III of the stipulation provides that no further adjustments other than those specifically identified in the stipulation would be made to DEP's base period revenue requirement. In addition, Paragraph 7 of Section II of the Revenue Requirement Stipulation notes that the Public Staff's proposal to return expiring amortizations to customers in a single rider only applies to non-CCR over-amortizations. Tr. Ex. vol. 7.

Based on the entire record in this proceeding, including the testimony cited above as well as the relevant provisions of the Revenue Requirement Stipulation, the Commission concludes that the CCR costs sought for recovery are reasonable and prudent and consistent with the CCR Settlement. The Commission also concludes that DEP has complied with the CCR Settlement and has made the agreed-upon adjustments in this case to reflect that settlement. The Commission approves DEP's applying the over-amortization of CCR costs as established in the 2017 Rate Case in the amount of $8.5 million against the CCR deferred balance in this case, and the Commission approves the recovery of the net deferred balance over a five-year period. The Commission also approves DEP's request to continue the deferral of any CCR cost DEP incurs subsequent to March 31, 2023, for future recovery consistent with the CCR Settlement.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-21

Harris Land Sales

The evidence supporting these findings of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts and Public Staff witnesses Zhang and Boswell; the Revenue Requirement Stipulation; and the entire record in this proceeding.

The Commission required deferral of the gains on the sale of excess land at DEP's Harris nuclear plant in its August 13, 1992 Order in Docket Nos. E-2, Subs 537 and 333. In 2020 and 2021, DEP completed five sales transactions of excess land and deferred the North Carolina retail share of the gains on those transactions in compliance with the Commission's order. Tr. vol. 13, 195. DEP proposes to amortize those deferred gains over

a six-year period. *Id.* The Public Staff, however, proposed a four-year amortization period. Tr. vol. 19, 72. The Revenue Requirement Stipulation provides for a three-year amortization period. Revenue Requirement Stipulation § III.22, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the evidence supports the three-year amortization period the parties propose in the Revenue Requirement Stipulation, and that the three-year amortization period is just and reasonable and fair to all parties and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-23

Roxboro Wastewater Treatment Regulatory Asset

The evidence supporting these findings of fact is in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts and the joint testimony and exhibits of Public Staff witnesses Zhang and Boswell; the Revenue Requirement Stipulation; and the entire record in this proceeding.

In the 2019 Rate Case, the Commission allowed DEP to establish a regulatory asset for the unrecovered costs associated with the Roxboro Wastewater Treatment Plant at the time of its early retirement. The Commission allowed amortization of the regulatory asset at the existing depreciation rate to continue until it determined an appropriate amortization period in a future rate case. DEP proposed to amortize the remaining regulatory asset over a five-year period. Tr. vol. 13, 189-90. Public Staff witnesses Zhang and Boswell recommended an amortization period of 11 years, consistent with the overall remaining depreciable life of the assets if they had remained in service. Tr. vol. 19, 71. The Revenue Requirement Stipulation, Section III, Paragraph 24, provides for a 12-year amortization period for the recovery of the Roxboro Wastewater Treatment Plant regulatory asset. Tr. Ex. vol. 7. The Commission concludes that the evidence presented supports the 12-year amortization period in the Revenue Requirement Stipulation, and that the 12-year amortization period is just and reasonable and fair to all parties and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24-25

Revenue Requirement Stipulation – Storm Securitization Overcollections

The evidence supporting these findings of fact is in DEP's verified Application and Form E-1, the testimony and exhibits of DEP witness Jiggetts, and the entire record in this proceeding.

In the Agreement and Stipulation of Partial Settlement with the Public Staff filed in Docket No. E-2, Sub 1262, DEP agreed to establish regulatory asset or regulatory liability accounts for the purpose of tracking up-front financing costs and servicing and administration fees related to storm securitization. In the instant proceeding, DEP proposed to amortize the regulatory liability of $1.0 million for overcollections associated with storm securitizations over a three-year period. Tr. vol. 13, 202-03. The Public Staff

did not oppose this recovery timeframe. No intervenor took issue with this proposal. The Commission concludes that the evidence supports the three-year amortization period DEP proposes, and that the three-year amortization period is just and reasonable and fair to all parties and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

Cost of Debt

The evidence supporting this finding of fact is in DEP's verified Application and Form E-1, the testimony and exhibits of DEP witness Newlin, the Revenue Requirement Stipulation, and the entire record in this proceeding.

DEP witness Newlin testified that DEP's long-term debt cost as of December 31, 2021, was 3.71%, which was the value DEP used to determine the revenue requirement in DEP's Application. Tr. vol. 9, 97. Section III, Paragraph 1 of the Revenue Requirement Stipulation establishes that the embedded cost of debt as of March 31, 2023 shall be used to calculate DEP's revenue requirement. Tr. Ex. vol. 7. DEP witness Jiggetts presented in her supplemental testimony that the embedded cost of debt as of March 31, 2023, is 4.03%.

No intervenor offered any evidence opposing this provision of the stipulation. The Commission therefore concludes that the use of a debt cost of 4.03% per the terms of Section III, Paragraph 1 of the Revenue Requirement Stipulation is just and reasonable to all parties considering all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

Accounting Adjustments in Revenue Requirement Stipulation

The evidence supporting this finding of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Council, Jiggetts, Quick, Speros, Stewart, Ray, and Turner, Public Staff witnesses Zhang and Boswell, McLawhorn, and Metz, and CIGFUR witness Gorman; the Revenue Requirement Stipulation; and the entire record in this proceeding.

Summary of Evidence

Incentive Compensation

In his direct testimony, DEP witness Stewart included as a cost of service incentive compensation at target levels that are assigned or allocated to DEP. Tr. vol. 16, 212. Public Staff witnesses Zhang and Boswell testified that incentive compensation related to the Earnings Per Share (EPS) and Total Shareholder Return (TSR) metrics for all employees should be removed from the revenue requirement because these metrics

provided a direct benefit to shareholders rather than ratepayers. Tr. vol. 19, 48-49. CIGFUR witness Gorman concurred with this assessment. Tr. vol. 21, 405.

In rebuttal, DEP witness Stewart refuted these contentions, asserting that metrics such as EPS and TSR are appropriate for recovery, as they benefit customers. Tr. vol. 23, 293-95.

The Revenue Requirement Stipulation establishes that DEP employee incentives should be adjusted to remove incentive pay related to EPS and TSR for the top levels of DEP's leadership, but not for the remainder of the employees. Revenue Requirement Stipulation § III.12, Tr. Ex. vol. 7. No intervenor took issue with this provision of the Revenue Requirement Stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Rent Expense

DEP witness Jiggetts' direct testimony included a pro forma adjustment to increase O&M expenses to reflect incremental rent expenses, net of savings, associated with the changes in the Charlotte real estate portfolio and the Duke Energy Plaza building. Tr. vol. 13, 187. Public Staff witnesses Zhang and Boswell removed the portion of rent expense related to the Duke Energy Plaza building because the building is still under construction and cannot be utilized for its intended purpose. Tr. vol. 19, 58. The Public Staff included additional amounts to bring the rent expense to a representative level by utilizing some 2021 costs and applying the updated DEBS allocation. In addition, the Public Staff expressed concerns about the real estate portfolio, considering the reduction in work force and DEP's new workforce model allowing employees to work a hybrid schedule, reducing the office facilities necessary at any given time. *Id.*

In rebuttal testimony, DEP witness Jiggetts testified that DEP does not agree with the Public Staff's adjustments to rent expense and that the rent expense as calculated by DEP reflects all known and measurable updates to the rent costs expected to be incurred by DEP. Tr. vol. 23, 76-77. In addition, she noted that DEP began incurring rent expense for the Duke Energy Plaza on January 1, 2023, and that DEP included a full year of expense for the building because, as explained in the rebuttal testimony of DEP witness Council, the detailed schedule for the building shows that all construction will be completed, and the building occupied by the effective date of the new rates in this proceeding. *Id.* at 77. Thus, she testified that the Duke Energy Plaza rent expense is a known and measurable and prudent and reasonable expense that will be incurred by DEP, which is a fact that the Public Staff had not challenged. *Id.* Further, she testified that because DEP is paying rent expense to DEC for the Duke Energy Plaza building, if the Duke Energy Plaza rent expense is removed from DEP's revenue requirement, the comparable adjustment to remove the rent income from DEC should be made to keep the revenue and costs between the affiliates aligned. *Id.* at 78. In her rebuttal testimony, DEP witness Council testified that the Duke Energy Plaza building is presently in use, with several floors currently occupied, and that the entire building is anticipated to be

completed and fully occupied by third quarter 2023, which is before the requested rates become effective in this case. *Id.* at 247.

The Revenue Requirement Stipulation, in Section III, Paragraph 13, provides for an increase in test year rent expense of $4,440,000 on a North Carolina retail basis for increased rent expense, net of depreciation savings. Tr. Ex. vol. 7. The parties further agreed to address the reasonableness and prudence of the costs of the Duke Energy Plaza in the DEC Rate Case in Docket No. E-7, Sub 1276. Tr. vol. 23, 78. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Reliability Assurance O&M Adjustment

In her direct testimony, DEP witness Turner testified regarding the importance of keeping DEP's remaining coal-fired assets in efficient working order to support customer's energy needs as DEP plans for those units' retirement and explained that DEP will continue to incur costs for these assets as appropriate and prudent to ensure that reliable cost-effective electricity remains available while DEP develops and implements replacement of the coal fleet. Witness Turner also testified that the fossil/hydro units operated efficiently and reliably during the test period. Tr. vol. 12, 94-95, 99.

In her supplemental testimony, witness Turner explained the rationale for DEP's pro forma adjustment to O&M expenses for reliability assurance. Witness Turner stated that the adjustment increased by $7.8 million the test period O&M costs related to planned reliability assurance projects. These additional projects are necessary to contribute to the reliability of plans for the Roxboro and Mayo plants and include winterization projects. Tr. vol. 12, 118.

Public Staff witness Metz testified regarding DEP's historic operations of its generating fleet since the 2019 Rate Case and other discrete performance metrics over the last decade. Part of his review considered the overall system reliability, service quality, and reasonableness of using DEP's test year O&M costs as a proxy for expected future costs. The primary purpose of the review was to determine whether and how DEP's historic operation of its generation fleet has changed. Witness Metz supported the use of the weighted equivalent availability factor (WEAF) or weighted equivalent unplanned outage factor (WEUOF), as well as other metrics, in reviewing fleet performance and noted that different conclusions are possible depending on the performance metrics one uses. He clarified that the intent of the review was not to determine reasonableness or prudence of DEP's historic operations of its fleets. Witness Metz concluded that the fossil fleet's performance has degraded over the last decade, and suggested that if that trend continues, reliability could be impacted, especially as these units must perform in a different manner than originally designed and as DEP removes other generation units from service. Witness Metz also noted DEP's reduction of fleet O&M expenses, which DEP accomplished in part by reducing staffing, in the years following its recent rate cases. Tr. vol. 16, 431-42, 447.

Witness Metz testified that there is merit to the proposed adjustment based on the coal unit availability and outage rates but also asserted that DEP reduced the level of ongoing generating plant non-fuel O&M expense the very next year after Commission approval in the last two general rate cases. Tr. vol. 16, 447. Based on the concerns he identified with O&M expenses and fleet performance, witness Metz recommended several modifications to the adjustment to coal test year O&M expenses (Form E-1, Item 10, NC-2160[7]):

- Since DEP should have already completed the Reliability Threat Analysis and Winterization O&M project work, witness Metz recommended exclusion of the costs related to Reliability Threat Analysis work from any proposed pro forma adjustment and supported the inclusion of a reduced amount for the Winterization O&M work. Tr. vol. 16, 449.

- Since the majority of the costs related to reliability improvements appeared to be capital-related rather than O&M related, witness Metz recommended inclusion of those costs in the MYRP and their exclusion from the pro forma adjustment. *Id.* at 450.

- Since there is no certainty that DEP will hire and continue to employ the proposed level of increased staff at the Roxboro and Mayo coal plants, witness Metz proposed decreasing by half DEP's 2023 staffing work request. *Id.*

- Witness Metz recommended that the Repair Hold category adjustment should be rejected because this category is an attempt to clear a backlog of a larger volume of inventory (spare parts) to be repaired. *Id.* at 449-51.

In her rebuttal testimony, DEP witness Turner described the challenge of optimizing plant investments and maintaining sufficient staffing for the coal-fired assets that DEP will retire in the near-term future. Mayo and Roxboro Stations will be the last DEP coal-fired stations DEP will retire, but DEP continues to need them to serve customers. Witness Turner explained that DEP must maintain the continued reliability of these units until replacement generation is in place. Witness Turner explained further that DEP's strategy for addressing this challenge has evolved as circumstances have changed. DEP seeks to allocate more investment to the fossil units that are the most efficient and economical, and therefore most often dispatched (as well as projected to be necessary over the long term), while still making prudent but measured investments in the coal units, balancing the need to maintain their reliability while looking forward to their eventual retirement. Tr. vol. 12, 121-22.

Witness Turner also responded to witness Metz's specific recommendations regarding the Reliability Assurance pro forma NC-2160 and provided additional details regarding this work. With respect to the major components/Reliability Threat Analysis work, she explained that DEP identified this work as necessary through the Reliability Threats

[7] Pro-forma NC-2160 was filed in DEP's February update.

Analysis that DEP conducted in late 2022 and that DEP intends the work to address large items of equipment DEP needs to maintain unit reliability. Witness Turner disagreed with witness Metz's recommendation to remove the costs for the major components/Reliability Threat Analysis work from the pro forma. She explained that the Reliability Threat Analysis is not winter storm related and that, therefore, DEP would not have done the work reflected in the pro forma item subsequent to previous winter storms. Tr. vol. 12, 124-25. Witness Turner testified that the winterization O&M project category represents work DEP identified as necessary in early 2023 following winter storm Elliott and includes the estimated cost of a study of needed repairs and installation of additional insulation, wind breaks, and updated heat trace systems to address freeze issues. Witness Turner stated that the operator workaround project category of reliability improvements represents a deeper level review of system health at the coal stations. The operator workaround project category typically addresses smaller items that can impact reliability, particularly when combined with other reliability issues. *Id.* at 127-29. Witness Turner testified that the staffing project category represents DEP's forward projection of costs, primarily salary, benefits, and overhead, to ensure that DEP has adequate resources to operate the coal units until retirement. *Id.* at 130-31. Witness Turner also testified that DEP identified the repair hold project category through the Reliability Threat Analysis and that it represents major components that do not have a readily available spare and have long lead times that supply chain challenges have exacerbated. *Id.* at 131-32.

Witness Turner also responded to witness Metz's testimony regarding fossil fleet performance and O&M investment, noting that it is important to view the entire fleet's performance and not focus solely on coal. Based on the equivalent forced outage factor (EFOF) metric, she stated that DEP's fossil fleet is performing consistent with or better than the industry average, and the natural gas units have exceeded industry average performance. Tr. vol. 12, 133-35. Witness Turner emphasized that the evaluation of fleet performance and reliability assurance needs has changed over time and will differ between coal units and natural gas units. She concluded that the Reliability Assurance pro forma represents the adjustments that DEP has identified as needed to maintain the coal units in reliable condition. *Id.* at 136-38.

The Revenue Requirement Stipulation provides for inclusion of an additional $6 million (North Carolina retail) of annual incremental spend for ongoing O&M for DEP's coal generation fleet for discrete programs and targeted categories that witness Turner lists in her supplemental and rebuttal testimony and for which she includes supporting workpapers. The parties agreed that DEP will track and report on an annual basis the actual spend and employee head count for each coal generation station over the MYRP period in a manner to be agreed upon between DEP and the Public Staff. DEP will record any cumulative underspend to a regulatory liability account accrued through the end of the MYRP period (September 2026) and return it to customers in the next general rate case. Revenue Requirement Stipulation § III.14, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn and Metz supported this provision in their settlement supporting testimony. Tr. vol. 13, 254-56, 259; Tr. vol. 16, 513.

The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding. DEP has demonstrated that these funds are necessary to maintain the reliability of the coal units until their anticipated retirement. The Public Staff raised valid concerns regarding the performance of the DEP fossil fleet, specifically the coal units, and the Commission recognizes that reviews of performance can have different results depending on the metric the reviewer uses to evaluate it. DEP's tracking and annual reporting of the actual spend and employee head count for each coal generation station over the MYRP period will help to further inform this discussion as these units' retirements approach. The parties' agreement that DEP will record any cumulative underspend to a regulatory liability account accrued through the end of the MYRP period and return it to customers in the next general rate case addresses the concerns the Public Staff raised regarding O&M spending. In its first annual report, the Commission directs DEP to update the Commission on the agreed-upon specifics for the tracking and reporting of the actual spend and employee head count for each coal generation station.

Aviation Expense

In its initial filing, DEP removed 50.0% of corporate-related aviation expenses allocated to DEP in the test period that are not related to aerial patrol. DEP witness Jiggetts testified that DEP believes these costs were reasonable, prudent, and appropriate to recover from customers, but elected to remove them in this case. Tr. vol. 13, 184. Public Staff witnesses Zhang and Boswell recommended, in addition to the 50.0% already removed by DEP, removal from DEP's cost of service of additional flight costs that the Public Staff found to be unrelated to the provision of utility service, including portions of certain commercial international flights. Tr. vol. 19, 49.

The Revenue Requirement Stipulation removes aviation expenses associated with international flights, in addition to the 50.0% of aviation expenses removed in the Application. Revenue Requirement Stipulation § III.15, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Executive Compensation

In its Application, DEP removed 50.0% of the compensation of the five Duke Energy executives with the highest level of compensation allocated to DEP. DEP witness Jiggetts explained that while DEP believes these costs are reasonable, prudent, and appropriate to recover from customers, DEP has, for purposes of this case, made an adjustment to this item. Tr. vol. 13, 181. Public Staff witnesses Zhang and Boswell recommended an additional adjustment to remove 50.0% of the benefits of these top five Duke Energy executives, noting that the adjustment was consistent with similar recommendations the Public Staff has made and the Commission has approved in past rate cases. Tr. vol. 19, 45-46.

Section III, Paragraph 16 of the Revenue Requirement Stipulation provides for removal of 50.0% of the benefits of the five Duke Energy executives with the highest amounts of compensation, in addition to the 50.0% of their compensation DEP removed in the Application. Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Charitable Contributions and Sponsorships

In his direct testimony, DEP witness Speros certified that DEP's cost of service does not include any expenditures for charitable contributions in accordance with the requirement of Commission Rule R12-13(a) as amended. Tr. vol. 13, 46. Witness Speros testified that Commission Rule R12-13(a) requires that in every application for a change in rates, a utility must certify in its prefiled testimony that its application does not include certain costs, including charitable contributions. *Id.* Witness Speros further explained that he performed additional reviews of DEP's cost of service to ensure that DEP did not include any costs that Commission Rule R12-13 prohibits in the Application. *Id.* at 47.

Public Staff witnesses Zhang and Boswell recommended an adjustment to charitable contributions of approximately $152,000 to exclude expense amounts paid to the Chambers of Commerce and other donations. Tr. vol. 19, 56; Tr. vol. 23, 59; the Public Staff Accounting Exhibit 1, Schedule 1, line 33, Tr. Ex. vol. 19. Witnesses Zhang and Boswell stated that these expenses should be disallowed because they do not represent actual costs of providing electric service to customers. Tr. vol. 19, 56.

In his rebuttal testimony, witness Speros explained that Chambers of Commerce promote business and economic development, which in turn helps to retain and attract customers to DEP's service territory. In addition, funds DEP paid to Chambers of Commerce that DEP does not specify as a donation or lobbying are in fact supporting business or economic development and DEP properly considers them utility operating expenses and includes them in DEP's cost of providing electric service to customers. Tr. vol. 13, 73.

The Revenue Requirement Stipulation establishes that no adjustment will be made to charitable contributions and sponsorships. Revenue Requirement Stipulation § III.17, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Board of Directors Expense

With respect to Board of Directors expense, Public Staff witnesses Zhang and Boswell recommended an adjustment to remove 50.0% of the expenses associated with the Board of Directors of Duke Energy that had been allocated to DEP, similar to the Public Staff's recommendation regarding executive compensation and benefits of the five Duke Energy executives with the highest level of compensation allocated to DEP in the

test period. Tr. vol. 19, 47. In his response, DEP witness Stewart indicated that the law requires DEP to have a Board of Directors and that the costs of being an investor-owned utility, including Board costs, are in fact costs of service. Tr. vol. 23, 304. He argued that it is not fair or reasonable to penalize DEP for being an investor-owned utility with attendant requirements to that corporate structure. *Id.*

The Revenue Requirement Stipulation accepts the Public Staff's recommended adjustments to the Board of Directors' expenses. Revenue Requirement Stipulation § III.18, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Lobbying Expense

In his direct testimony, DEP witness Speros certified that DEP's cost of service does not include any expenditures for lobbying, political or promotional advertising, political contributions, or charitable contributions in accordance with the requirement of Commission Rule R12-13(a) as amended. Tr. vol. 13, 47. Witness Speros further explained that he performed additional reviews of DEP's cost of service to ensure that DEP did not include costs that Commission Rule R12-13 prohibits in the Application. *Id.* With respect to lobbying expenses, Public Staff witnesses Zhang and Boswell adjusted O&M expenses to remove additional costs associated with Federal Government Affairs, Governmental Affairs and External Relations, and National Engagements that DEP recorded above the line in the test year. Witnesses Zhang and Boswell stated that Commission Rule R12-12 and the Commission's Order in Dominion Energy North Carolina's 2012 Rate Case (2012 DENC rate case) justify removal of these expenses. Tr. vol. 19, 50.

In rebuttal testimony, witness Speros stated that DEP disagrees that any adjustment to remove any additional cost from the cost of service under Commission Rule R12-12 or the Commission's decision in the 2012 DENC rate case is necessary. Tr. vol. 13, 63.

The Revenue Requirement Stipulation establishes that, while DEP maintains its position that its cost of service in this case did not include any lobbying expenses, for the purposes of settlement, DEP accepted the adjustments proposed by the Public Staff for lobbying expenses. Revenue Requirement Stipulation § III.19, Tr. Ex. vol. 7. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Nuclear End-of-Life Reserve

Public Staff witness Metz recommended an $8 million disallowance of four-year Repair Hold and Quality Assurance (QA) Hold costs for nuclear inventory that has been on hold for four years or more. Tr. vol. 16, 427-28. He further recommended that a 5.0%

salvage value be applied to nuclear materials and supplies (M&S) inventory for purposes of calculating DEP's end of life nuclear reserve. *Id.* at 430.

In his rebuttal testimony, DEP witness Ray opposed witness Metz's recommendation of removal of $8 million from the end-of-life nuclear reserve, explaining that DEP holds this inventory to support plant operations and it is therefore beneficial to customers. Tr. vol. 23, 282. Witness Ray clarified that the fact that DEP maintains an item of M&S inventory in Repair Hold or QA Hold longer than four years does not mean that DEP will not ultimately use such inventory or have it available for use. *Id.* at 282-85. Regarding salvage value, witness Ray testified that if DEP receives approval of its requests for subsequent license renewal of its nuclear units, there will be few to no similar technology nuclear plants in operation at the time DEP's units retire in the next 20 years. With few to no similar vintage nuclear or coal plants in operation, the market for the more expensive inventory items such as pumps, motors, and valves will be severely limited or nonexistent. DEP does not expect markets for inventory components at or near market value to exist. Witness Ray indicated that, while DEP generally agrees that there may be some small amount of salvage value for nuclear M&S inventory at its end of life, disposal expenses will largely offset any such value. He concluded that DEP does not support maintaining a particular salvage value going forward until the retirement of the nuclear units because doing so would reduce DEP's ability to adjust the salvage value for M&S inventory as needed in the future based on changed circumstances. *Id.* at 288.

The Revenue Requirement Stipulation accepts the Public Staff's adjustment to end-of-life nuclear materials and supplies reserve expense, reduced as described in the direct testimony of Public Staff witness Metz. Revenue Requirement Stipulation § III.20, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn, Metz, Zhang, and Boswell supported this provision in their settlement supporting testimony. Tr. vol. 13, 254, 60; Tr. vol. 16, 512. The Commission concludes that the adjustments to the nuclear end-of-life reserve established in the Revenue Requirement Stipulation are supported by the evidence presented, is just and reasonable and fair to all, and should be approved.

Coal Inventory

Based on DEP's historical performance, updated coal inventory analysis, and recent coal inventory holdings, Public Staff witness Michna recommended that DEP maintain its current coal inventory of 35 days of 100.0% full load burn and reduce the corresponding DEP adjustment that increased coal inventory to 40 days by $9,971,719 to account for this change. Tr. vol. 21, 292-93.

DEP witness Turner opposed witness Michna's adjustment. Witness Turner asserted that the adjustment failed to contemplate the changing market factors impacting a reliable fuel supply, namely the inability of the coal supply chain to timely respond to volatility in coal generation demand and ignored DEP's updated average inventory of 38.8 days. Witness Turner concluded that it is prudent to increase the target from 35 days to 40 days. Tr. vol. 12, 142.

The Revenue Requirement Stipulation accepts the annual 35 full load day burn average to establish the level of coal inventory for purposes of establishing a revenue requirement. Revenue Requirement Stipulation § III.21, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn, Metz, Zhang, Boswell supported this provision in their settlement supporting testimony. Tr. vol. 13, 254, 261; Tr. vol. 16, 513-15. The Commission concludes that the 35-day coal inventory target proposed in the Revenue Requirement Stipulation is supported by the evidence presented, is just and reasonable and fair to all, and should be approved.

Credit Card Payment Fees

In her direct testimony, DEP witness Quick proposed to offer a Fee-Free program for small and medium nonresidential customers who make payments using debit, credit, prepaid, or electric check (Card Payments) to pay their electric bills. Tr. vol. 7, 65. In support of DEP's request, she noted that residential customers have a transaction Fee-Free program for Card Payments, which the Commission approved in DEP's last general rate case. Witness Quick recounted that nonresidential customers making a Card Payment are subject to a convenience fee of $8.50 per payment for payments up to $10,000; for payments in excess of $10,000, the convenience fee is 2.75% of the amount paid. *Id.* at 105. DEP's vendor charges the convenience fee and DEP receives no portion of it. *Id.* at 105-06. Based on customer feedback and requests, witness Quick proposed in this case to offer the Fee-Free program for Card Payments to nonresidential customers making bill payments up to $3,000. *Id.* at 106. DEP, instead of the customer, would pay the vendor the convenience fees for these Card Payments and incorporate the expense into the cost of service for recovery through its base rates. Tr. vol. 7, 104-06.

In their joint testimony, Public Staff witnesses Zhang and Boswell opposed DEP's proposal to socialize the credit card payment fees for nonresidential customers. Tr. vol. 19, 51. They noted that the current volume of customers who use this method of payment accounts for less than 1.0% of the overall bill pay transactions volume. *Id.* Additionally, witnesses Zhang and Boswell distinguished this proposal from the socialization of the residential credit card fees the Commission allowed in DEP's previous general rate case order by noting that the residential Fee-Free program had the potential to produce reductions in late payments and uncollectibles, but nonresidential customers do not experience the same level of late payments and uncollectibles as residential customers. *Id.* Therefore, they testified that they found no offsetting benefit of socialization of Card Payment fees for the nonresidential customers to general ratepayers. *Id.*

The Revenue Requirement Stipulation establishes that the credit card payment fees for nonresidential customers shall be removed from the revenue requirement in this case. Revenue Requirement Stipulation § III.23, Tr. Ex. vol. 7. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Payroll and Benefits

DEP and other Duke Energy affiliates continuously review operational matters including workforce staffing levels. In connection with such a review, DEP implemented planned headcount reductions beginning in 2021 through the first part of 2023, leading to a reduction in DEP's otherwise applicable revenue requirement. While DEP witness Jiggetts' schedules reflected the reduction through the March 31, 2023 cutoff date applicable to this case, Section III, Paragraph 25 of the Revenue Requirement Stipulation provides for a further reduction of the revenue requirement for the payroll costs and associated benefits for the former employees subject to the Work Reduction Initiative through the end of May 2023. *Id.* No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

Production O&M Reduction to Reflect Capitalization Policy Change

In his supplemental testimony, Public Staff witness Metz described how DEP reclassified miscellaneous line items from O&M to capital plant. Witness Metz did not take issue with this action for purposes of this proceeding but testified to his concern that test year O&M expenses used to establish an ongoing expectation of future spending may be overstated. To account for the impact of the reclassification, he recommended the removal of $463,000 on a system basis from DEP's test year expenses. Tr. vol. 16, 506-08.

The Revenue Requirement Stipulation establishes a reduction in production O&M of $463,000 on a system basis to account for the change in DEP's capitalization policy. Revenue Requirement Stipulation § III.26, Tr. Ex. vol. 7. DEP witness Jiggetts and Public Staff witnesses McLawhorn, Metz, Zhang, and Boswell supported this provision in their settlement supporting testimony. Tr. vol. 13, 254, 262; Tr. vol. 16, 512. The Commission concludes that the production O&M reduction proposed in the Revenue Requirement Stipulation is supported by the evidence presented, is just and reasonable and fair to all, and should be approved.

Vegetation Management O&M

In his direct testimony, DEP witness Maley described DEP's transmission Integrated Vegetation Management (IVM) Plan and its goal of removing and/or controlling incompatible vegetation within and along transmission rights of way. Witness Maley indicated that the IVM includes planned corridor work, reactive work, and floor management work, with DEP's prioritizing the first two categories based on threat assessments. Witness Maley also indicated that DEP had included an increase in vegetation management costs in its test period pro forma adjustments to account for increased outside labor costs and that this adjustment also covers vegetation management costs associated with the expansion of existing substation sites. Tr. vol. 10, 178-79.

In his direct testimony, DEP witness Guyton testified that DEP utilized a reliability prioritization model to drive its routine IVM program. The other important components of

DEP's vegetation management include the following programs: herbicide management, hazard trees, reactive customer requested activities, and post outage vegetation management activities. Witness Guyton also testified that DEP continues to utilize a seven-year cycle for distribution vegetation management in nonurban areas and a three-year cycle in urban areas consistent with DEP's 2015 Tree Growth Study. Tr. vol. 10, 51-52.

In his direct testimony, Public Staff witness T. Williamson described DEP's IVM Plan and provided a summary of the operation of that plan since 2015. This description included both vegetation within DEP's rights of way and vegetation that lies outside DEP's rights of way. DEP's hazard tree program manages the vegetation which lies outside DEP's rights of way. Witness T. Williamson also recommended changes to DEP's assessment activities (which would increase the frequency of its review of distribution lines), and recommended reductions in two parts of the Distribution System Vegetation Management budgets. Finally, witness T. Williamson recommended changes to the Distribution and Transmission vegetation plan reporting requirements. Tr. vol. 21, 205-18.

In his rebuttal testimony, DEP witness Guyton addressed Public Staff witness T. Williamson's vegetation plan recommendations and indicated that the significant increase in work that would be necessary to implement his recommendations for increased observation of the distribution system would increase costs and endanger DEP's ability to meet its other vegetation management plan goals. Witness Guyton further stated that reductions in Distribution Vegetation Management plan budgets were contrary to DEP's actual experience of increasing vegetation management costs. Tr. vol. 10, 143. Witness Guyton also objected to two of the additional reporting requirements witness T. Williamson suggested on the grounds that the practicalities of how the vegetation management plan operates precludes reporting on vegetative miles and hazard tree targets. *Id.*at 147.

No other party presented evidence on these matters.

The Revenue Requirement Stipulation provides for a reduction in DEP's Distribution O&M Demand Program budget to $2,721,604[8] and for adoption of the additional vegetation management reporting requirements recommended by Public Staff witness T. Williamson except for reporting on vegetative miles and hazard tree targets, as noted on page 52 of the rebuttal testimony of DEP witness Guyton. Revenue Requirement Stipulation §§ III.27 and IV.37, Tr. Ex. vol. 7. The Commission concludes that these adjustments in the Revenue Requirement Stipulation are supported by the evidence presented and are just and reasonable and fair to all and should be approved.

Lead-Lag Study

As part of its filing in this case, DEP submitted a lead-lag study that was performed by Ernst & Young, LLP, and approved in the Commission's Order in the 2019 Rate Case.

[8] The $2,721,604 is the adjusted total related to O&M Demand Program. The amount of the adjustment was $789,309 on a system basis.

Tr. vol. 13, 43; Speros Direct Ex. 2, Tr. Ex. vol. 13. The lead-lag study was used to analyze transactions throughout the year to determine the number of days between the time services are rendered and payment is received (revenue lag), and the number of days between the time expenditures are incurred and payment is made for such services (expense or payment lead). Public Staff witnesses Zhang and Boswell recommended that DEP prepare and file a fully updated lead-lag study in its next general rate case. Tr. vol. 19, 43.

In his rebuttal testimony, DEP witness Speros stated that DEP plans to pursue a merger of the DEP and DEC utilities in the next rate case and will work with the Public Staff to determine if the timing of the next lead-lag study makes more sense before or after that case. Tr. vol. 13, 73.

The Revenue Requirement Stipulation incorporates DEP's agreement to perform a lead-lag study before the next general rate case proceeding and incorporate the results of that study in DEP's next rate case application. No intervenor took issue with this provision of the stipulation. The Commission concludes that the Revenue Requirement Stipulation provides a reasonable resolution of this issue for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 28.

The evidence supporting this finding of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of Public Staff witnesses Metz, Zhang, and Boswell, including Accounting Second Supplemental Ex. 1, the Supplemental Revenue Requirement Stipulation, including Ex. 1; and the entire record in this proceeding.

The Revenue Requirement Stipulation involves a comprehensive resolution between the stipulating parties of a majority of the revenue requirement issues in this case. Because the Revenue Requirement Stipulation was entered into before the Public Staff had completed its audit of DEP's third and final update of costs, the stipulation provides expressly that the stipulation does not prevent the Public Staff from completing its audit of DEP's updates or making proposed adjustments to the updated revenue requirements based on the audit. The Public Staff completed its audit of the updates in June 2023, and the Public Staff and DEP entered into the Supplemental Revenue Requirement Stipulation, filed on June 27, 2023, in which the parties agreed to certain further minor adjustments to the revenue requirement. The Supplemental Revenue Requirement Stipulation lists four areas of agreement between DEP and the Public Staff. Tr. Ex. vol. 24.

Sheds (New Hill Timpson Training Sheds)

DEP and the Public Staff agreed that DEP shall remove 50% of the costs associated with the New Hill Timpson Training Sheds from its revenue requirement for purposes of this proceeding only. The removal will result in a decrease of $186,000 in Plant in Service on a North Carolina retail basis. *Id.*

Wilson 230kV Project

DEP and the Public Staff agreed that DEP will reclassify $670,989 system amount related to the Wilson 230kV project from distribution to transmission plant. They further agreed that DEP shall offset the March 2023 plant in service amount of $1.423 million on a system basis associated with the Wilson 230kV project with an estimate of the insurance proceeds in the amount of $897 thousand on a system basis that DEP will receive. The parties acknowledged that actual proceeds received may be different than the estimates captured and agree that they will address any necessary adjustments in a future proceeding. *Id.*

Laptop Issuance

DEP and the Public Staff agreed that, for purposes of this proceeding, DEP will remove new laptop devices not issued to employees as of the capital cutoff date from the revenue requirement. The removal will result in a decrease to Plant in Service of $2,370,000 on a North Carolina retail basis. *Id.*

Capitalization Policy

DEP and the Public Staff agreed that there will be no adjustment to the capitalized costs related to the February 2023 Brunswick Unit 2 nuclear refueling outage in this proceeding. They further agreed that DEP will assist the Public Staff in reviewing DEP's capitalization procedures before DEP files its next general rate case. *Id.*

On June 27, 2023, the Public Staff filed the joint supplemental settlement testimony of witnesses Metz, Zhang, and Boswell in support of the Supplemental Revenue Requirement Stipulation. According to the Public Staff witnesses, the most important benefits that the stipulation and the agreed upon adjustments provide are: (1) an aggregate reduction in DEP's proposed revenue increase in this proceeding; and (2) the avoidance of litigation between the parties on the settled issues and the associated increased accumulation of rate case expense recovery from ratepayers. Tr. vol. 24, 47. The Public Staff further testified that the Commission should approve the Supplemental Revenue Requirement Stipulation because of these benefits to ratepayers. *Id.*

The Commission concludes that the adjustments in the Supplemental Revenue Requirement Stipulation are supported by the evidence presented and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

MYRP Capital Investments

The evidence supporting this finding of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Maley, Guyton, Ray, Turner, Strasburger, and LaRoche, Public Staff witnesses Thomas, Metz, T. Williamson, Nader,

Zhang, and Boswell, AGO witness Nelson, NCJC, et al. witnesses Hill and Duncan, , Sierra Club witness Goggin; the Revenue Requirement Stipulation; and the entire record in this proceeding.

In its Application, DEP identified capital spending projects projected to be placed in service during the MYRP period. These projects consist of transmission and distribution infrastructure, solar and battery storage, enterprise technology and security, and fossil, hydro, and nuclear investments.

DEP provided support for its MYRP projects through its Application, direct, supplemental direct, and rebuttal testimony of DEP witnesses discussed below, as well as at the July 2022 Transmission and Distribution Technical Conference. Furthermore, the Public Staff conducted substantial discovery regarding the projects DEP proposed in its MYRP. DEP's witnesses assert that DEP has provided sufficient information to justify the MYRP projects, while the Public Staff witnesses offered multiple critiques of DEP's documentation of the MYRP projects. The Revenue Requirement stipulating parties agreed to support the MYRP projects as modified in the Revenue Requirement Stipulation.

Transmission

DEP witness Maley testified in support of the MYRP transmission projects. Regarding future needs, witness Maley testified that, while DEP has worked hard to maintain the system and reliably meet customer needs, it must do more to improve the state's energy infrastructure to meet the challenges and opportunities that lie ahead. Tr. vol. 10, 170. Witness Maley testified that DEP designed its MYRP to address future challenges and opportunities and that the MYRP transmission projects include investments in the following categories: system intelligence, hardening and resiliency, transformer and breaker upgrades, and capacity and customer planning. *Id.* at 185.

Witness Maley testified that DEP selected and grouped targeted reliability improvements in the following MYRP projects, based on the areas that provide the greatest value to customers: system intelligence, vegetation management, transmission line hardening and resiliency, substation hardening and resiliency, transformer upgrades, breaker upgrades, and capacity and customer planning. *Id.* at 187. He explained that although these seven proposed MYRP investments are the same as those DEP presented in the July 25, 2022, MYRP Technical Conference, DEP has refined some of the location details and informed the Cost Benefit Analysis (CBA) with those details. *Id.*

In witness Maley's direct testimony and accompanying exhibits, he described the estimated costs of DEP's proposed MYRP transmission projects. *Id.*

In his supplemental direct testimony, witness Maley provided an update on the cost estimates applicable to transmission projects that DEP included in its MYRP based on certain criteria agreed upon with the Public Staff. *Id.* at 212-13. Witness Maley identified additional transmission MYRP project locations that DEP added to the MYRP after filing

his direct testimony, and identified those that it removed, along with the reasons behind such changes. *Id.* at 208. He provided updated project cost estimates for certain transmission MYRP projects, including explanations for the basis for such updated cost estimates. *Id.* at 212-13.

DEP witness Maley's Direct Supplemental Exhibit 1 provides the total updated costs of the proposed MYRP Transmission projects as follows:

1. Breakers - $103,434,999;

2. Capacity and Customer Planning - $624,078,511;

3. Substation Hardening and Resilience - $359,579,976;

4. System Intelligence - $72,766,544;

5. Transmission Line Hardening and Resiliency - $129,651,500;

6. Transformers - $114,269,580; and

7. Vegetation Management - $113,884,377.

Tr. Ex. vol. 10.

The modifications to proposed MYRP Transmission projects described in witness Maley's supplemental direct testimony and accompanying exhibits resulted in an updated estimated capital cost of DEP's proposed MYRP Transmission projects of $1,517,665,486.

Public Staff witness Metz testified as to multiple concerns with the MYRP projects, including outdated cost estimates, insufficient staffing levels to complete the projects on schedule, and the lack of coordination between business groups to increase project efficiencies. Tr. vol. 16, 461, 465-66, 481-83. Witness Metz recommended reducing the project contingency by half, arguing that DEP failed to justify the high contingency amount DEP budgeted for the projects. *Id.* at 491-92. He further recommended a 5.0% downward adjustment for all transmission projects in the MYRP to address potential construction efficiencies that could arise in the implementation of the MYRP. *Id.* at 494. Witness Metz also recommended the removal of certain transmission projects from the MYRP based on the analysis of Public Staff witness Chiles. *Id.* at 458.

AGO witness Nelson critiqued DEP's transmission planning and made several recommendations. AGO witness Nelson recommended that the Commission require DEP to conduct a study on the costs and benefits of grid-enhancing technologies (GETs). Tr. vol. 18, 123-30. Witness Nelson also recommended that DEP engage in regional transmission planning and asserted that regional planning could potentially displace projects in the MYRP. *Id.* at 138-41. Finally witness Nelson recommended that DEP pursue all funding options for transmission projects that are part of the IRA. *Id.* at 134.

Sierra Club witness Goggin recommended that the Commission require DEP to file a proactive transmission plan for all transmission expansion and upgrades needed to accommodate the interconnection of all new renewable resources required by 2035 under Duke's Carbon Plan. Tr. vol. 21, 789. Witness Goggin also recommended that the Commission direct DEP to use a "multi-value approach to planning transmission so that the identified upgrades meet needs related to public policy, economics, reliability, expanded interconnection with neighboring Balancing Authorities, and other categories of benefits…" Tr. vol. 21, 790.

Witness Maley addressed testimony from Public Staff witnesses Metz and Chiles. Specifically, he: (1) spoke of each MYRP project witnesses Metz and Chiles challenged and explained why the projects are necessary and appropriate for inclusion in the MYRP; (2) discussed DEP's methodology for ensuring that there is no overlap between the scope of different projects; (3) countered the argument that the Commission should reduce contingency components of the estimates for all MYRP transmission projects by 50.0%; (4) explained the basis for the contingency component of DEP's transmission projects; and (5) addressed witness Metz's recommendation that the Commission reduce all transmission project estimates by 5.0%. Tr. vol 10, 227-29, 246-47.

Witness Maley also addressed testimony of witnesses for the AGO and the Sierra Club. Witness Maley stated that he disagreed with AGO witness Nelson's recommendations. *Id.* at 259-60. Witness Maley testified that witness Nelson's recommendation to study GETs is inappropriate in this proceeding because the Commission already considered GETs in the Carbon Plan proceeding. *Id.* at 260. Also, witness Maley disputed witness Nelson's recommendations because they require activities already underway or that should be considered in the Carbon Plan or in the North Carolina Transmission Planning Collaborative (NCTPC). *Id.* Witness Maley mentioned that DEP witness Roberts explained how GETs are evaluated in his Carbon Plan testimony. Witness Maley stated that the Commission has already noted in its Carbon Plan Order that it "expects Duke to pursue all potential tax incentives or federal funding." *Id.* Witness Maley countered that new requirements imposed in this proceeding that circumvent resource planning and transmission planning are not reasonable. *Id.*

In his rebuttal testimony, witness Maley responded that Sierra Club witness Goggin's recommendations regarding transmission planning would fit better in the Carbon Plan and Integrated Resource Process (CPIRP) efforts than within the limited three-year window of the MYRP. Tr. vol. 10, 261. Witness Maley explained that Duke Energy stated in the March 15, 2023, NCTPC Transmission Advisory Group (TAG) presentation that it is pursuing the integration of a multi-value strategic transmission planning study into the local transmission planning process. Tr. vol. 10, 261. Since DEP is already pursuing this in the NCTPC, witness Maley testified that any further requirement is unnecessary. *Id.*

The Revenue Requirement Stipulation includes a 50.0% adjustment to the contingency amounts of the transmission projects as recommended by Public Staff witness Metz. The stipulation further provides that DEP will leverage project efficiencies to the extent practical in the implementation of the MYRP. The stipulation also establishes

that the transmission MYRP projects identified in DEP witness Abernathy's February 2023 MYRP update of Exhibit 4, Workpaper 5 and described in the direct and supplemental testimonies of DEP witness Maley are appropriate for inclusion in the MYRP. Based on the entire record in this proceeding, the Commission finds that DEP's proposed transmission projects are reasonable and shall be included in the MYRP for recovery. Tr. Ex. vol. 13.

The only parties that opposed portions of DEP's transmission projects included in the MYRP but not resolved through the Revenue Requirement Stipulation and other settlements are the AGO, as indicated by the testimony filed by AGO witness Nelson, and the Sierra Club, as indicated by witness Sierra Club witness Goggin.

The Commission agrees with DEP witness Maley's assertion that the recommendations of AGO witness Nelson and Sierra Club witness Goggin regarding transmission planning are designed to change DEP's decision-making regarding the types of transmission projects it undertakes. The Commission finds that the appropriate proceeding for consideration of changes to transmission planning is the CPIRP, or other proceedings.

N.C.G.S. § 62-133.16(c)(1)(a) provides that for the first year of an MYRP, the

> base rates . . . shall be fixed in a manner prescribed under G.S. 62-133 . . . plus costs associated with a known and measurable set of capital investments, net of operating benefits, associated with a set of discrete and identifiable capital spending projects to be placed in service during the first rate year.

The same provision specifies that:

> [s]ubsequent changes in base rates in the second and third rate years of the MYRP shall be based on projected incremental Commission-authorized capital investments that will be used and useful during the rate year and associated expenses, net of operating benefits, including operation and maintenance savings, and depreciation of rate base associated with the capital investments, that are incurred or realized during each rate year of the MYRP period.

N.C.G.S. § 62-133.16(c)(1)(a).

After having carefully reviewed all the evidence in the record, the Commission concludes that the evidence demonstrates that the proposed MYRP transmission projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission further concludes that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding these transmission projects and that the transmission MYRP costs thereunder are just and reasonable and consistent with the public interest.

Distribution

DEP witness Guyton described the discrete and identifiable capital spending projects associated with DEP's distribution system proposed to be placed in service for each rate year of the MYRP. His testimony included the reason for, scope of, timing for (projected in-service month and year), and operating benefits of each project. Tr. vol. 10, 35-36. Witness Guyton testified that DEP's proposed MYRP distribution and other projects covered in his testimony total $2.2 billion and include the $1.8 billion in distribution MYRP projects discussed at the T&D technical conference held on July 25, 2022, as well as $0.4 billion in other non-T&D MYRP projects. *Id.* at 42. The other MYRP project categories include DEP's allocated share of the costs of enterprise communications and enterprise systems, as well as facilities and fleet electrification infrastructure. *Id.* These other projects are closely aligned with the distribution business or enabling the grid capabilities. *Id.*

While discussing the preliminary findings in the ongoing Climate Risk and Resilience Study (CRRS) of the Carolinas transmission and distribution system, witness Guyton testified that the preliminary findings of the CRRS reinforces the benefits of the proposed MYRP projects, and that the additional headroom provided by capacity upgrades and improvements accommodates customer load growth and generation, but also increases resilience to the effects of extreme heat. *Id.* at 63-64. He testified that targeted undergrounding, distribution hardening and resiliency, and hazard tree removal increase resilience to the impact of wind and storms, which are likely to increase in frequency and strength due to climate change. *Id.* at 64. Witness Guyton also testified that Duke Energy implemented Integrated Systems Operations Planning (ISOP) to leverage increasing amounts of data, such as the propensity of customers to adopt solar and purchase EVs, when planning future projects. *Id.* at 40. He testified that, when appropriate, the distribution projects will take advantage of new processes and technologies that will aid in the delivery of the energy goals and requirements of North Carolina. *Id.* at 40-41. As such, he stated that the proposed MYRP projects and the grid capabilities that are achieved through these projects will serve as a foundation to support future technologies, and will result in significant customer benefits, particularly in the areas of reliability and resiliency. *Id.* at 41.

With respect to reliability, witness Guyton stated that DEP anticipates fewer and shorter outages resulting from programs such as Self-Optimizing Grid (SOG), Targeted Underground (TUG), distribution automation, and equipment retrofitting. *Id.* Regarding resiliency, the MYRP projects will provide increased protection against physical/cyber-attacks and severe weather impacts. Increases in capacity and voltage regulation and management will accommodate increasing amounts of renewable resources and Distributed Energy Resources (DERs). *Id.* Enhanced automation and control, and situational awareness will enable DEP to operate the grid more efficiently and support new customer programs, which will provide customers more options to control their energy usage and decrease their energy costs. *Id.* Witness Guyton testified that DEP will spread its proposed distribution MYRP projects across its service territory and retail customer classes to provide equitable access to these benefits. *Id.* The programs in

DEP's MYRP projects make the grid more flexible and adaptable. Automation and control technologies will help generate and capture large volumes and types of data which was not previously available. *Id.* Witness Guyton asserted that these benefits are helpful not only for DEP's Grid Operators but also for its Planning Engineers as they analyze and model DEP's grid for future improvements and capabilities using ISOP toolsets like Morecast and Advanced Distribution Planning (ADP). *Id.* at 41-42. He indicated that grid technologies will continue to and will be integrated into new solutions to address changing customer needs. *Id.* at 42.

Witness Guyton testified that distribution projects included in the MYRP total $2,197,627,366 in estimated capital investment and fall into four investment categories: (1) Substation and Line MYRP projects which total estimated capital costs of $1.582 billion comprise most of the distribution MYRP project costs; (2) Retail and System Capacity Projects which total estimated capital costs of $0.210 billion include the traditional identification and execution of capacity projects to support traditional loads as well as DERs and EVs; (3) Hazard Tree Removal Projects which total estimated capital costs of $0.028 billion consist of the traditional identification and execution of hazard tree removal which is performed in conjunction with normal trimming cycles; and (4) non-transmission and distribution MYRP projects which total estimated capital cost of $0.4 billion include DEP's allocated share of the cost of enterprise communications and systems as well as facilities and fleet electrification infrastructure. *Id.* at 42-44, 64-65.

Witness Guyton testified that the Substation and Line MYRP projects are geographically based and include a combination of ongoing work necessary for safe and reliable service and the work necessary to deliver essential grid capabilities that DEP has identified to address the megatrends and support the clean energy transition. *Id.* at 42. DEP's Distribution MYRP consists of the following 12 programs:

1. SOG Program, also known as the smart-thinking grid, redesigns key portions of the distribution system and transforms it into a dynamic self-healing network that isolates grid issues and limits customer impacts to hundreds versus thousands of customers. The total capital cost for this program is $231.9 million.

2. Voltage Regulation and Management Program improves the grid's ability to address intermittency and fluctuations that DERs cause and improves power quality to customers. The total capital cost for this program is $204.6 million.

3. Distribution Automation Program targets the lateral segments of the grid and focuses on modernizing single-use fuses with automated devices capable of intelligently resetting themselves for reuse. The total capital cost for this program is $50.3 million.

4. Capacity Upgrades and Improvements Program consists of the same work that DEP has always performed to serve its new and existing customers. The total capital cost for this program is $461.6 million.

5. Hardening and Resiliency – Laterals Program focuses on the lateral sections or tap lines, which branch from the main feeder lines and feed neighborhoods, businesses, and commercial/industrial customers. The total capital cost for this program is $175.3 million.

6. Hardening and Resiliency – Public Interference Program improves reliability by targeting DEP's most outage prone overhead backbone power line sections most impacted by vehicle accidents and determining the proper hardening and resiliency solution to reduce the number of outages customers experience. The total capital cost for this program is $18.1 million.

7. Hardening and Resiliency – Storm Program consists of improvements to locations of the distribution grid that DEP has identified, through analysis of historical outage data, as being more vulnerable to outage impacts from extreme weather events. The total capital cost for this program is $77.2 million.

8. Equipment Retrofit Program improves reliability by targeting equipment prone to outages from animal interference, lightning, and clearance issues by upgrading the assets to modern design standards. The total capital cost for this program is $80.4 million.

9. Long Duration Interruption (LDI) Program relocates segments of main overhead feeder lines in hard-to-access areas to improve accessibility for utility trucks. The total capital cost for this program is $2.6 million.

10. TUG Program improves reliability by strategically identifying DEP's most outage prone overhead power line sections and relocating them underground to reduce the number of outages customers experience. The total capital cost for this program is $103.0 million.

11. Hazard Tree Removal Program maintains or improves reliability by identifying and removing dead, structurally unsound, dying, diseased, leaning, or otherwise defective trees that could strike electrical lines or equipment of the distribution system from outside the maintained right of way. The total capital cost for this program is $48.0 million.

12. Distribution Infrastructure Integrity Program identifies and mitigates risk factors such as end-of-service equipment, technology obsolescence, and damaged in-service distribution equipment. The total capital cost for this program is $366.1 million. *Id.* at 66-71.

.Witness Guyton testified that DEP's description of its distribution MYRP programs and associated exhibits reflect the detailed project information that Commission Rule R1-17B. *Id.* at 72. The projected annual net O&M benefits that Commission Rule R1-17B(d)(2)k requires reflect the operational O&M savings offset by the incremental cost to operate the new technology. *Id.* at 73. The O&M savings stem from fewer outages

resulting from reliability improvements and the reduction in vegetation management resulting from the undergrounding of overhead lines, for example, in the TUG program. *Id.* DEP netted these savings with the ongoing O&M costs associated with maintaining the added equipment installed under the SOG and Voltage Regulation programs. *Id.*

In his supplemental direct testimony, witness Guyton identified distribution MYRP project locations that DEP either added to or removed from the MYRP period and explained the reasons for such changes. *Id.* at 88-89. Witness Guyton provided updated project cost estimates for certain distribution MYRP projects and explained the basis of the updated cost estimates. *Id.* Witness Guyton testified that his direct testimony included 44 distribution projects (comprised of 301 distribution sub-projects at the location/task level) totaling $2.2 billion, while his supplemental direct testimony included 44 distribution projects (comprised of 297 sub-projects at the location/task level) totaling $2.0 billion representing an overall net reduction of $226.7 million across all the distribution MYRP projects. *Id.* Additionally, he testified that DEP and the Public Staff reached a consensus regarding the criteria pursuant to which DEP would update information regarding MYRP projects and their cost estimates. The updates to the distribution MYRP projects witness Guyton presented in his supplemental direct testimony meet those criteria. *Id.* at 90.

DEP removed three project locations from the MYRP period, including deferring the Franklinton 115kV location within the Substation and Line – Triangle North 262 MYRP Project totaling $0.9M to a later time outside the MYRP window, and moving both the Advanced Distribution Management System (ADMS) CVR project location, totaling $1.7M, and the ADMS Advanced Fault Location project, totaling $0.6M, outside the MYRP window. *Id.* at 91-92. Witness Guyton described cost updates to 148 total distribution MYRP projects. *Id.* at 92. Witness Guyton also explained that at the time of DEP's Application, the distribution MYRP projects were at various stages of the project management lifecycle under DEP's Project Management Center of Excellence (PMCoE) standards. *Id.* at 93. Under the PMCoE approach, as a project moves through the development cycle, DEP continues to refine the costs and project schedules based on project development, detailed design, and construction planning. *Id.* at 93.

Witness Guyton testified that the Substation and Line and Area Capacity projects comprise a significant percentage of the MYRP distribution projects. *Id.* at 94. When these projects were initially identified, a spreadsheet cost estimate was constructed based on past work scope completed for similar assets at similar locations primarily based on engineering analysis and data driven models *Id.* Planning and engineering activities that occurred after the filing of DEP's Application and engaged in as part of the PMCoE process provided the opportunity to refine the scope of work and cost estimates on 125 of the total 190 Substation and Line sub-projects at the location/task level in the MYRP based on actual circuit and equipment and site conditions. *Id.* at 94-95.

Guyton Supplemental Direct Exhibit 3 identifies the total estimated capital costs of the Distribution MYRP projects to be $1,970,915,190. Tr. Ex. vol. 10.

Public Staff witness Thomas recommended reduction of the project costs for four Area Capacity projects and one Facilities project to align with updated cost estimates. Tr. vol. 19, 218. Specifically, he recommended reduction of the cost estimates for the Wilmington 421 230kV Capacity, Wilmington Sunset Park 115kV #2 Capacity, Youngsville 115kV Capacity, Wake Tech 230kV Capacity, and Aberdeen Facilities projects. *Id.* Witness Thomas also recommended reduction of the cost estimates for the Area Capacity program by 5.0% as a financial incentive for DEP to maximize efficiencies for the Area Capacity and Substation and Line programs. *Id.* at 222-23.

Public Staff witness Metz raised multiple concerns about the MYRP projects, including outdated cost estimates, insufficient staffing levels to complete the projects on schedule, and the lack of coordination between business groups to increase project efficiencies. Tr. vol. 16, 461, 465-66, 481-83. Witness Metz recommended reducing the project contingency by half, arguing that DEP failed to justify the high contingency amount DEP budgeted for the projects. *Id.* at 491-92. Public Staff witness Lawrence recommended removal of the costs for the Electrification Charging Infrastructure (ECI) Program that would support the deployment of electric vehicles to DEP facilities and the homes of select DEP employees from the MYRP because DEP had not provided sufficient information or support for the program. Tr. vol. 21, 172-75.

NCJC, et al. witnesses Hill and Duncan made several recommendations related to DEP distribution planning. First, they recommended that the Commission initiate a working group to redesign DEP's CBA methodologies for selection of projects in the MYRP and that the Commission initiate an investigation into distribution system planning. Tr. vol. 21, 849, 874. Witnesses Hill and Duncan also recommended that the Commission require DEP to conduct non-wire (NW) pilot projects and that DEP update its MYRP cost estimates to account for federal funds available through the IRA and IIJA. *Id.* at 850-54, 879.

In his rebuttal testimony, DEP witness Guyton responded to the Public Staff's distribution related MYRP and base case testimony, and to NCJC, et al. witnesses Hill and Duncan's testimony. Tr. vol. 10, 97-98. Specifically, he: (1) described the process DEP used to select certain distribution projects for inclusion in the MYRP and provided specific, data-driven reasons why their selection was appropriate; (2) discussed the methodologies and procedures DEP used to develop cost and contingency estimates for distribution projects; (3) countered the argument that the Commission should reduce contingency components of the estimates for all distribution projects in the MYRP by 50.0%; and (4) addressed witness Thomas's recommendation that the Commission reduce certain distribution project estimates by 5.0%.

The Revenue Requirement Stipulation included certain modifications to DEP's MYRP distribution projects. Those modifications include: (1) inclusion of the 50.0% adjustment to the contingency amounts of the distribution projects as recommended by Public Staff witness Metz; (2) rejection of project efficiency adjustment to the MYRP revenue requirement but DEP agreement to leverage project efficiencies to the extent practical in the implementation of the MYRP; (3) removal of the costs of the Fleet Electrification Charge Infrastructure Project; (4) inclusion of the cost of Project Walter in

the MYRP; (5) agreement to discuss scope and content of proposed reporting on reliability O&M; (6) reduction of the Wilmington 421 230kV Capacity, Wilmington Sunset Park 115kV #2 Capacity, Youngsville 115kV Capacity, Wake Tech 230kV Capacity, and Aberdeen Facilities project cost estimates; and (7) reduction in the costs of the Substation & Line Targeted Undergrounding projects. Tr. Ex. vol. 7.

The Revenue Requirement Stipulation did not address the concerns raised by NCJC, et al. witnesses Hill and Duncan.

In response to the recommendations of NCJC, et al. witnesses Hill and Duncan, witness Guyton testified that the recommendations fail to acknowledge activities that are already underway, and for which Commission approval is therefore unnecessary. *Id.* at 105. Witness Guyton asserted that the recommendation of NCJC, et al. that the Commission initiate a working group to update DEP's CBA methodologies is unnecessary since DEP has demonstrated the current methodology, and no other intervenor disputed the current methodology or its usefulness in the current rate case. Tr. vol. 10, 149-50. He contends that witnesses Hill and Duncan also do not acknowledge specific improvements in the CBA methodology DEP used in the current rate case that DEP made in response to stakeholder feedback in DEP's last rate case. *Id.* at 150. Witness Guyton also asserted that the NW pilot projects witnesses Hill and Duncan suggest are unnecessary because DEP has already initiated other customer-solution NW approaches. Tr. vol. 21, 854-55. Witness Guyton points out that their recommendation that the Commission initiate distribution system planning is not necessary because the Commission has already initiated the ongoing ISOP stakeholder engagement efforts. *Id.* at 870. Similarly, witness Guyton asserts that their recommendation to require DEP to update MYRP cost estimates to account for federal funds available through the IRA and IIJA is unnecessary as DEP is actively pursuing grant funding opportunities for the benefit of customers. Tr. vol. 10, 151. Witness Guyton also points to DEP witness Abernathy's testimony, in which she testified that DEP requests that the Commission issue an accounting order authorizing deferral of all IRA and IIJA impacts, including benefits and costs, for addressing in a future filing. *Id.*

The Commission gives significant weight to the compromise agreements reflected in the Revenue Requirement Stipulation. The Commission is not persuaded that the recommendations of NCJC, et al. witnesses Hill and Duncan related to DEP's proposed MYRP distribution projects are necessary at this time. The majority of the recommendations of witnesses Hill and Duncan are related to distribution system planning that should be considered in other proceedings such as the CPIRP proceeding. With respect to witnesses Hill and Duncan's recommendation that the Commission require DEP to update its distribution MYRP investments to account for available federal funds, the Commission notes that the record demonstrates that DEP is pursuing such funds and re-emphasizes its direction to DEP to pursue such funds. As discussed later in this Order, impacts associated with the IIJA and IRA will be deferred, and the Commission declines to adopt Witness Hill and Duncan's recommendation related thereto.

After having carefully reviewed all the evidence in the record on DEP's distribution MYRP proposal in this docket, and based on that evidence, the Commission finds that DEP's

distribution MYRP projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission further concludes that the evidence supports approval of the Revenue Requirement Stipulation's provision regarding these distribution MYRP projects.

Nuclear

DEP witness Ray testified in support of the nuclear projects DEP included in the proposed MYRP, the process DEP used to select the projects, and the method by which DEP calculated projected costs for the projects. Tr. vol. 16, 171-72. Witness Ray explained that DEP selected the projects based on their value in maintaining safe and reliable operation of the nuclear stations and on a high level of confidence in their cost estimates and schedule. Witness Ray stated that DEP based the projected costs on its long-range nuclear planning tool, which it updates regularly. *Id.* at 170. Witness Ray presented additional details regarding nuclear fleet-wide projects and the projects DEP planned for each of DEP's nuclear stations. *Id.* at 173-76; Application at 15-16, Tr. Ex. vol. 7. He concluded that DEP prudently and reasonably selected these projects as they will enable DEP to maintain the fleet in reliable and efficient condition for customers' benefit. *Id.* at 172. Witness Ray's Direct Exhibit 1 provided additional details regarding projected cost, schedule, scope, and justification for each nuclear MYRP project. Tr. Ex. vol. 16.

In his supplemental direct testimony, DEP witness Ray updated the information on the MYRP nuclear projects. Witness Ray testified that DEP did not include any new nuclear projects with its supplemental filing, but identified two nuclear projects that it was postponing until after the MYRP period and, therefore, removed from the MYRP. Tr. vol. 16, 179-80. Witness Ray explained the basis for updating MYRP project costs as agreed upon with the Public Staff and the method by which DEP developed the updated project costs. *Id.* at 181-83. Witness Ray's Supplemental Exhibits 1 and 2 provided updated in-service dates and projected costs for the nuclear MYRP projects. Tr. Ex. vol. 16

Public Staff witness Metz discussed the Public Staff's review of DEP's initial and supplemental MYRP filings and updates. Witness Metz testified that the Public Staff initiated multiple sets of discovery and participated in multiple meetings with DEP on the MYRP. Tr. vol. 16, 458. The Public Staff did not make any adjustments or raise any concerns with the need for, scope of, or projected costs for the nuclear MYRP projects. *Id.* at 478-81.

In his rebuttal testimony, DEP witness Ray noted that neither the Public Staff nor any other party recommended rejection or cost reduction for any nuclear projects DEP proposed for the MYRP. Tr. vol. 23, 289.

Based on the entire record in this proceeding, the Commission finds that DEP's projected nuclear MYRP capital investments satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a) and will be used and useful in the appropriate rate year. The Commission notes that no party offered any evidence to challenge any of the nuclear

MYRP projects. Therefore, the Commission concludes the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding the nuclear MYRP projects.

Fossil/Hydro

In her direct testimony, DEP witness Turner outlined the projected natural gas, coal, and hydroelectric capital investments DEP included in the MYRP. Witness Turner described DEP's prioritization process for identification of the projects to include in the MYRP. Tr. vol. 12, 101-02. She explained that DEP applied its project management guidelines for project scope development and cost estimation. *Id.* at 102. Witness Turner presented additional details regarding the MYRP projects proposed for the natural gas, coal, and hydro generation fleets. *Id.* at 105-08; Application at 16, Tr. Ex. vol. 7. Witness Turner also testified to the importance of keeping DEP's remaining coal fired assets working efficiently to support customer's energy needs as DEP plans for those units' retirement and explained that DEP will continue to incur costs for these assets as appropriate and prudent to ensure that reliable cost-effective electricity remains available while DEP develops and implements replacement of the coal fleet. She noted that due to the continued importance of natural gas to DEP's resource mix, particularly during winter months and while DEP is developing and deploying energy storage capacity, DEP will continue to rely on its natural gas fleet as part of the diverse and dispatchable resource mix. *Id.* at 94-95. She concluded that DEP's decision to invest in these projects is prudent and reasonable as they will enable DEP to continue to provide safe, reliable, and affordable service to customers as well as comply with regulatory requirements. *Id.* at 105-06. Witness Turner's Direct Exhibit 1 provided additional details regarding projected cost, schedule, scope, and justification for each fossil/hydro MYRP project.

In her supplemental direct testimony, DEP witness Turner supported the additional fossil and hydro projects that DEP proposed to include in its MYRP. Tr. vol. 12, 112-15. She explained why certain projects that DEP removed from the MYRP were determined to be no longer necessary. *Id.* at 115-16. Witness Turner explained the basis for updated MYRP projected costs as agreed upon with the Public Staff and the method by which DEP developed the updated project costs. *Id.* at 116-17. Witness Turner's Supplemental Exhibits 1 and 2 provided updated in-service dates and projected costs for the fossil and hydro MYRP projects and cost, schedule, scope, and reasoning information for the newly added fossil and hydro projects. Tr. Ex. vol. 12.

Public Staff witness Metz testified that the Public Staff reviewed DEP's initial and supplemental MYRP filings and updates, initiated multiple sets of discovery, and participated in multiple meetings with DEP on the MYRP. Tr. vol. 16, 458, 478-81. Public Staff witness Michna testified that he did not dispute the inclusion of Steam Plant in Service projects in the MYRP, and that he agreed with DEP's philosophy of prioritizing unit reliability and resource adequacy in capital spending decisions. Tr. vol. 21, 302. Public Staff witness Thomas recommended a delay in the in-service date for the Blewett Falls fish passage project that would move the project from MYRP Rate Year 1 into MYRP Rate Year 2 due to previous and anticipated extensions of commencement of operations, and a reduction the projected cost for the project based on his review of the contractor

bid selection and internal funding approval processes, which he concluded resulted in significant excess contingency for the project. Tr. vol. 19, 208-13.

In rebuttal testimony, DEP witness Turner described how DEP's cost estimates for the Blewett Falls fish passage project, particularly the contingency allotted for the project, were based on the project's unique nature and challenges. Witness Turner disagreed with the delay of the project in service date to MYRP Rate Year 2, explaining that the timing for testing of the project is separate from the capital project construction, which according to current plans should go in service during Rate Year 1. Tr. vol. 12, 147-50.

The Revenue Requirement Stipulation accepts the Public Staff's recommended changes to the Blewett Falls fish passage project cost estimate and postponement of this project's in-service date to March 2025. Revenue Requirement Stipulation § III.33.e, Tr. Ex. vol. 7. Further, the stipulation accepts the Public Staff's recommendation for inclusion of the costs of the Blewett Falls fishing pier in the MYRP and removal from the historic test period. Revenue Requirement Stipulation § III.33.a, Tr. Ex. vol. 7. DEP witnesses Abernathy and Jiggetts and Public Staff witnesses McLawhorn and Metz supported these provisions in their settlement supporting testimony. Tr. vol. 13, 138-40, 262; Tr. vol. 16, 514.

Based on the entire record in this proceeding, the Commission finds that DEP's proposed natural gas, coal, and hydro MYRP projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). DEP demonstrated that these projects are primarily in the normal course of business for maintaining the fossil and hydro fleets for reliability, safety, and regulatory compliance. In addition, DEP provided substantial evidence regarding the continued importance of the coal and natural gas fleets to its ability to continue to provide reliable service to customers and the need to continue to invest in the coal fleet until its retirement and in the natural gas fleet to reliably manage the transition away from coal. The Commission further concludes that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding these fossil/hydro projects.

Cybersecurity

In his Supplemental Direct Testimony, DEP witness Strasburger provided support for DEP's information technology (IT)/operational technology (OT) Cybersecurity project DEP will include in the MYRP. Tr. vol. 16, 184-88. Witness Strasburger explained that the purpose of the IT/OT Cybersecurity project is to assure safe and sustainable operations through proactive and effective cybersecurity design, implementation and operation of critical energy systems and their underlying technology. *Id.* at 186. He testified that the IT/OT Cybersecurity project will update OT governance and risk and compliance standards and processes, implement a new OT specific asset, patch and vulnerability management system, and deliver new OT cybersecurity threat logging and monitoring capabilities. *Id.* at 185-86. The project will also focus on expanding monitoring and threat response capabilities and will introduce proactive elements to reduce cybersecurity risks. *Id.* at 186. He noted that his Strasburger Exhibit 1 contained information regarding the IT/OT Cybersecurity project required by Commission Rule R1-17B(d)(2)j.(i)-(iii). He further testified that as DEP continues to see increased cyber threats against operational

assets, including potential geopolitical threats, cybersecurity becomes a larger component of DEP's energy transition and grid protection initiatives, and that the Commission should approve the MYRP IT/OT Cybersecurity project. *Id.* No other party offered any evidence regarding DEP's MYRP Cybersecurity project.

After having carefully reviewed the entirety of the evidence in the record on DEP's MYRP IT/OT Cybersecurity project, the Commission finds that the IT/OT Cybersecurity MYRP project satisfies the requirements set forth in N.C.G. S. § 62-133.16(c)(1)(a). DEP demonstrated that cybersecurity is becoming an increasingly critical component of its energy transition and grid protection initiatives, and that the IT/OT Cybersecurity project is reasonably necessary. Additionally, no party offered evidence to the contrary. The Commission further concludes that DEP put forth a reasonable plan to implement the IT/OT Cybersecurity project within the prescribed time period.

Battery Storage

DEP proposes a portfolio of MYRP battery energy storage projects. Tr. vol. 11, 22. The portfolio consists of six discrete and identifiable battery energy storage projects: (1) Riverside; (2) Warsaw; (3) Lake Julian; (4) Elm City; (5) Knightdale; and (6) Craggy. *Id.* DEP witnesses Tompson and Shearer (the Battery Energy Storage Panel) testified and detailed the projected cost, schedule, and scope for each MYRP project, as well as the reasoning for each project as Commission Rule R1-17B(d)(2)j requires. *Id.* at 21; *see also* Battery Energy Storage Panel Ex. 1, Tr. Ex. vol. 11. According to the Battery Energy Storage Panel, the proposed investments represent near-term investments that will play an integral role in the next phases of the energy transition. Tr. vol. 11, 21. Evidence appearing in Battery Storage Panel Exhibits 1-2 includes detailed information regarding projected cost, schedule, scope, and rationale supporting the investments. *Id.* Battery Energy Storage Panel Exhibit 2 also includes anticipated project timelines, including projected in-service month and year for each proposed project as Commission Rule R1-17B(d)(2)j requires. *Id.*

DEP's Battery Storage Panel testified as to the expected benefits associated with each proposed battery project including unique bulk power services. Tr. vol. 11, 23-25. The panel testified that battery resources are uniquely capable of serving multiple grid functions across generation, transmission, and distribution systems. *Id.* at 25. The panel testified that the Craggy, Lake Julian, and Riverside projects each comply with the Western Carolinas Modernization Project (WCMP) and support the Mountain Energy Act. *Id.* at 23-24. Additionally, the battery projects at Elm City and Warsaw both leverage and provide experience with surplus solar interconnection capacity, and they also utilize existing interconnection infrastructure thereby reducing development costs and project timelines. *Id.* at 24. Furthermore, the Knightdale battery project will be the largest battery DEP has installed and this size project provides the next phase of critical operating experience. *Id.* The Knightdale battery project will provide bulk system services including energy arbitrage and ancillary services with a grid scale battery system. *Id.* at 24-25.

Public Staff witness Thomas testified regarding DEP's proposed battery energy storage portfolio. Tr. vol. 19, 184-99. Witness Thomas recommended that DEP classify the Craggy battery project as 50.0% "Other Production Plant" and 50.0% "Transmission Plant," given that DEP sited and sized the project for a potential transmission deferral. *Id.* at 197. Witness Thomas noted that DEP has classified all battery storage projects as "Other Production Plant," with interconnection costs separated into either Transmission Plant or Distribution Plant, depending on where the facility interconnects to the grid. *Id.* at 196. For most of the projects, witness Thomas found this approach to be reasonable absent clear guidance from FERC. *Id.* For Craggy, however, witness Thomas testified that DEP identified Craggy as part of a first of a kind non-wires alternative study and sized and sited the project for a potential transmission deferral designed to alleviate a future DEP-West balancing area transmission constraint. *Id.* at 197. For those reasons, witness Thomas recommended reclassification of the Craggy battery project as 50.0% "Other Production Plant" and 50.0% "Transmission Plant." *Id.*

The Battery Energy Storage Panel rebutted witness Thomas' Craggy-related recommendation, asserting that the proposed project would not defer a transmission investment. Tr. vol. 11, 49. The panel explained that the Craggy battery would mitigate against certain delays in implementing the 230kV Craggy-Enka line project; however, it would not defer transmission investment entirely. *Id.* at 48. The panel further testified that DEP does not anticipate dispatching the Craggy battery for transmission deferral purposes – the proposed project remains cost-effective based on low interconnection costs in an area with limited generation resources. *Id.* The panel maintained that the originally proposed allocation of 100.0% Production for the project is reasonable. *Id.* at 49.

The Revenue Requirement Stipulation adopts the allocation factor by plant classification for the Craggy battery project, as proposed by DEP. Revenue Requirement Stipulation § III.33.c, Tr. Ex. vol. 7.

After careful review all the evidence in the record on DEP's MYRP proposal in this docket, and based on that evidence, the Commission finds that DEP's battery storage MYRP projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission further finds that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding the battery storage MYRP projects.

Solar

DEP witness LaRoche addressed the need, rationale, and cost estimates for two solar development projects a solar project from the 2022 Solar Procurement Program DEP expects to be in service between 2025 and 2026 (2026 Solar Investment Project) and a 9.5 MW solar facility DEP proposes to place in service at the DEP Asheville Generating Plant site in Buncombe County by September 2025 (Asheville Solar Project). Application at 14; Tr. vol. 16, 113-18. Witness LaRoche stated that to identify the 2026 Solar Investment Project, DEP considered the solar investments that will result from the 2022 Carolinas Carbon Plan, the 2022 Solar Procurement Program Request for Proposals, and DEP's WCMP commitments. Tr. vol. 16, 113. Additionally, he testified that

DEP's most recent integrated resource plan (IRP) identified the need for new solar resources to reliably serve DEP's projected customer load. *Id.* at 114. Witness LaRoche also stated that N.C.G.S. 62-110.9 was a "key driver" of the 2026 Solar Investment Project, as that statute requires DEP and DEC to take all reasonable steps to achieve 70.0% carbon emission reductions by 2030 and carbon neutrality in North Carolina by 2050. *Id.* The WCMP, approved by the Commission on March 28, 2016, was also a primary regulatory driver of the program, as the Asheville Solar Project directly relates to and is a commitment stemming from the WCMP. *Id.* at 116.

Public Staff witness Thomas recommended that the Commission delay the in-service date for the Asheville Solar Project to March 2026. Tr. vol. 19, 181. Witness Thomas stated that he based this recommendation on DEP's history of delays with solar project completion as well as the potential for new challenges that may emerge during project development and construction. *Id.* at 181-82. Additionally, the Public Staff is concerned about the Asheville Solar project's costs, as the cost per kW is 50.0% higher than the cost per kW for the 2026 Solar Investment project. *Id.* at 181.

Regarding the delayed in-service date, DEP witness LaRoche testified in his rebuttal testimony that the use of historical delays is inappropriate, as blanket comparisons between past and future solar projects are not on an apples-to-apples basis. Tr. vol. 23, 262. For example, witness LaRoche noted that Public Staff witness Thomas cited DEP's delays in the Woodfin project to support his recommended delay but did not assess whether the same delays are likely to impact the Asheville Solar Project or whether DEP has taken steps to mitigate that risk. *Id.*

After having carefully reviewed the evidence in the record on DEP's Solar MYRP proposal in this docket, and based on that evidence, the Commission finds that DEP's solar MYRP projects satisfy the requirements set forth in N.C.G.S. § 62-133.16(c)(1)(a). The Commission concludes that the evidence supports approval of the Revenue Requirement Stipulation's provisions regarding the solar MYRP projects.

MYRP Implementation

Public Staff witness Metz testified to his concern regarding DEP's ability to complete the proposed MYRP projects within the three-year MYRP period. Based on his review of DEP's historic and projected 2023 staffing, Witness Metz asserted that DEP does not have a plan to increase staffing for planned MYRP projects while continuing to perform traditional work of the utility. Tr. vol. 16, 465-81.

In his rebuttal testimony, DEP witness Murray overviewed DEP's wholistic and comprehensive approach to project planning and execution while noting that neither the Public Staff nor any party recommended disallowance or rejection of any MYRP project based on generalized project execution risks or challenges. Tr. vol. 23, 313. Witness Murray discussed how Duke Energy's Project Management Center of Excellence (PMCoE) creates a common framework for managing projects across the enterprise and how DEP has successfully implemented prudent management processes historically.

While acknowledging that MYRP project execution will not be easy and that there likely will be unforeseen challenges that require DEP to, in some cases, modify planning MYRP projects to maximize benefits for customers, he explained that MYRP project execution is not a challenge that is fundamentally different than challenges inherent in DEP's historic capital project implementation and disagreed with the suggestion that DEP is not well prepared to successfully execute these projects. Tr. vol. 23, 312-18.

DEP witness Bowman also responded to the witness Metz's concerns regarding DEP's ability to execute on certain MYRP projects. Tr. vol. 21, 1211. She testified that DEP is confident in its ability to execute the MYRP projects and acknowledged DEP's obligation, as confirmed by the Commission, to continually assess the MYRP projects and ensure that customer benefits are maximized throughout the execution phase. *Id.* She explained that although DEP will encounter unforeseen challenges and circumstances, in all instances DEP will leverage its execution experience to maximize benefits for customers. *Id.*

After review of the evidence presented by DEP's various generation, transmission, and distribution witnesses, as well as the evidence presented by DEP regarding its processes, procedures, and project management experience the Commission finds that DEP has the obligation to prudently and reasonably implement the MYRP in a manner that benefits its customers. Any modification to the implementation of MYRP projects will be reported by DEP on a quarterly basis, as required under Commission Rule R1-17B(h(2)) and will be subject to audit in future base rate case proceedings. While the Commission recognizes the risk about which the Public Staff is concerned, the Commission determines, on the evidence presented, that DEP has demonstrated a reasonable plan to complete the MYRP projects within the prescribed time periods.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

Reporting Requirements

The evidence supporting this finding of fact is included in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Bowman, Abernathy, Jiggetts, and Guyton, and Public Staff witnesses Zhang, Boswell, McLawhorn, Metz, Nader, T. Williamson, and Thomas; the Revenue Requirement Stipulation; and the entire record in this proceeding.

Rider EC

In his testimony, Public Staff witness Nader testified that to ensure that the proposed Rider EC continues to be in the public interest, the Commission should require annual reporting on the impacts of Rider EC. Tr. vol. 21, 106. Witness Nader recommended that DEP should report the gross level of incentives DEP paid, the number of recipients, the amount of investment, load, and jobs associated with the incentives, and an overall marginal cost analysis of Rider EC to determine if the gross level of incentives DEP paid exceeds the marginal cost to serve the gross pool of participants. *Id.*

CIAC Reporting

In their joint direct testimony, Public Staff witnesses Zhang and Boswell stated that DEP was booking contributions in aid of construction (CIAC) related to interconnection agreements (IA) inconsistently. Witnesses Zhang and Boswell recommended that the Commission order DEP to review its CIAC policy to ensure that DEP properly accounts for CIAC and report the results of that review in the next general rate case. Tr. vol. 19, 39-40. In rebuttal, DEP witness Speros rebutted the notion that DEP was booking its CIAC related to IAs inconsistently but stated that DEP did not oppose in principle reporting to the Commission on its CIAC policy in the next general rate case. Tr. vol. 13, 63.

Vegetation Management Reporting

Public Staff witness T. Williamson recommended that the Commission require DEP to perform additional reporting requirements beyond the Vegetation Management Program Performance report DEP files annually. He recommended that DEP report on the additional following topics: (1) distribution vegetation management herbicide actuals, target, and variance for spending and miles; (2) distribution vegetation management number of miles of vegetated distribution lines that require trimming or herbicide treatment; (3) distribution vegetation management hazard tree program actuals, target, and variance for spending and tree counts; and (4) distribution vegetation management reactive/demand events, and the number of events worked annually. Tr. vol. 21, 217-18. In his rebuttal testimony, witness Guyton stated that DEP can provide the recommended additional distribution reporting requirements beyond the Vegetation Management Program Performance DEP files annually with two exceptions. Tr. vol. 10, 147.

Hot Springs CBA

In his testimony, Public Staff witness Thomas recommended the Commission direct DEP to perform an updated cost benefit analysis for Hot Springs. Tr. vol. 19, 194. He further recommended that DEP provide the updated cost benefit analysis with its operational report for the Hot Springs facility on October 31, 2023, in Docket No. E-2, Sub 1185. *Id.*

Discussion and Conclusions

The Revenue Requirement Stipulation establishes certain reporting obligations. Specifically, Paragraph 34 obligates DEP to report on Rider EC, subject to agreement of the Revenue Requirement stipulating parties regarding the scope and content of the report. Paragraph 35 obligates DEP to report on the CIAC issue in its next general rate case application. Paragraph 36 addresses a reporting on reliability O&M as discussed by Public Staff witness Metz, and a management reporting requirement as discussed by Public Staff witness T. Williamson, except for reporting on the two issues noted in the rebuttal testimony of DEP witness Guyton. In Paragraph 38, the Revenue Requirement stipulating parties agree to discuss the need for a report on the Hot Springs CBA as requested in the testimony of Public Staff witness Thomas. Besides the exceptions noted

in Paragraphs 34-38 of the Revenue Requirement Stipulation, Paragraph 39 indicates that DEP agrees to all reporting requirements proposed by the Public Staff.

No other party offered any evidence addressing the reporting obligations outlined in the Revenue Requirement Stipulation. The Commission concludes that the reporting obligations agreed-upon in Section IV of the Revenue Requirement Stipulation are reasonable. Based upon the record evidence and consistent with the Revenue Requirement Stipulation, the Commission finds and concludes that the reporting obligations outlined in Section IV of the Revenue Requirement Stipulation are approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

The evidence supporting this finding of fact is in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Hunsicker, Quick, and Jiggetts; the supplemental and settlement testimonies of Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

In prior DEP rate cases, including Dockets No. E-2, Sub 1023, E-2, Sub 1142, and E-2, Sub 1219, the Commission has approved a calculation of "storm normal" expenses based upon a 10-year average of storm costs, after reducing the costs associated with major storms, to include in rates. Witness Jiggetts explained the methodology for the calculation of storm normal in this case. Tr. vol. 14, 29-30. The resulting amount to include in rates per DEP's calculation is approximately $22.2 million. Jiggetts Partial Settlement Ex. 4, Tr. Ex. vol. 14.

No party disputes DEP's calculation of storm normal expenses to include in rates, and DEP witness Jiggetts testified that the Public Staff agrees with the amount as calculated by DEP. Tr. vol. 14, 58.

Accordingly, the Commission finds that the appropriate North Carolina retail normalized annual level of storm costs to include in DEP's rates in this case is $22.243 million.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 32-34

Distribution System Demand Response

The evidence supporting this finding is in the verified Application and Form E-1; the testimony and exhibits of DEP witnesses Jiggetts and Hunsicker; the testimony and exhibits of Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

In this case, DEP proposed to move the future costs associated with its DSDR energy efficiency program from the DSM/EE rider into base rates starting on the effective date for the new rates established in this proceeding as the Commission instructed in its Order from the 2019 Rate Case. Tr. vol. 13, 204. DEP witness Jiggetts explained that

DEP will continue to recover costs deferred to the regulatory asset before the effective date for new rates in this proceeding through the DSM/EE rider until they are fully amortized. *Id.* Public Staff witnesses Zhang and Boswell testified that DEP's proposal to recover the future DSDR costs in base rates is appropriate because all customers benefit from DSDR. Tr. vol. 19, 74.

No party opposed DEP's request.

Payment Navigator

The evidence supporting this finding is in the verified Application; the testimony and exhibits of DEP witnesses Jiggetts and Quick; and the entire record in this proceeding.

In her direct testimony, DEP witness Jiggetts stated that DEP proposed several new programs in this rate case to benefit customers, including the CAP, the Tariffed On-Bill program, and the Payment Navigator Program that DEP witnesses Harris and Quick also discussed in their testimony. If the Commission approves each program, DEP requests permission to establish a regulatory asset and defer to the account the incremental implementation and administration O&M costs related to the programs. Tr. vol. 13, 209.

DEP witness Quick described DEP's Affordability Ecosystem in her direct testimony. The Affordability Ecosystem is a multi-pronged approach to assist customers who have challenges in affording to pay their electric utility bills. The Affordability Ecosystem includes products and services, including bill pay assistance and weatherization programs, and DEP equips its customer service team to inform customers about opportunities to address their affordability challenges. Tr. vol. 7, 75. Consistent with DEP's Affordability Ecosystem, witness Quick requested approval of the Payment Navigator program, which DEP specifically designed to comprehensively support not only low-income customers in arrears on their bills, but all customers seeking assistance in managing their electric utility bills. *Id*. at 172. The Payment Navigator program is based on a pilot that DEP tested during the COVID-19 pandemic with customers seeking support in paying their electric bills. *Id*. at 175-77. As witness Quick described, in accordance with the Payment Navigator program, DEP proactively contacts customers who are struggling with arrearages to invite them to speak with a Payment Navigator specialist. A Payment Navigator specialist is a call center agent trained to empathetically handle more complex calls assisting customers who have fallen behind in their bills, and the specialist can take the necessary time to work with customers on obtaining the assistance they need. *Id.* at 177. Based on the customer's situation, the Payment Navigator specialist may tailor a unique set of recommendations to assist the customer in becoming current on payments and provide longer-term guidance on how to ease the customer's electric energy burdens by connecting the customer to assistance funding, referring them to energy efficiency or demand side management options, or enrolling them in programs like Budget Billing, Pick Your Own Due Date, and more. *Id.* at 78-79.

DEP witness Quick highlighted the positive feedback and insights that DEP received regarding the Payment Navigator pilot and the success that DEP had in referring customers to agencies for assistance, enrolling them in deferred payment arrangements, and recommending flexible billing programs. *Id.* at 79. During the pilot, by assisting customers to access this available funding, Payment Navigator helped customers obtain all the funding available to them from certain assistance agencies, in contrast to previous years when agencies' funds were not utilized. *Id*. at 175-76. Witness Quick also stated that during the pilot, DEP learned that about 50.0% of the customers that DEP contacted were not aware of the assistance available to them. She noted that some customers have difficulty reading and completing applications, and DEP learned during the Payment Navigator pilot that customers dropped out sometime during the application process and did not complete the applications. Witness Quick indicated that Payment Navigator specialists could benefit customers by working with them to complete the applications so that they can access all available funding. Tr. vol. 22, 132-33.

DEP witness Quick also testified that Payment Navigator would complement the CAP that DEP witness Harris described. She noted that CAP will directly benefit customers by reducing their monthly electric energy burden through a bill discount. After a customer enrolls in CAP, DEP can continue to work with the customer to understand the customer's needs and analyze what other products and services (such as Share the Light, Budget Billing, energy efficiency offerings, weatherization, and payment plans) are available to support the customer over the longer term. Tr. vol. 7, 80.

Witness Quick concluded by requesting that the Commission approve the Payment Navigator program and associated costs, which she estimated to be $3 million over the next three years. She noted that the deferral request that DEP witness Jiggetts describes in her testimony addresses the associated incremental O&M costs that the $3 million estimate includes. Witness Quick testified that DEP would not defer any capital costs associated with the program. *Id*. at 80-81

No party contested the implementation of the Payment Navigator program.

Customer Connect

In its Application, DEP requested recovery of the approximately $60 million North Carolina retail allocated capital investment associated with implementation of its Customer Connect project, the new customer engagement platform, and CIS. Tr. vol. 16, 71, 82. DEP witness Hunsicker testified that in November 2021, DEP implemented the Customer Connect platform including a CIS, which is a system that manages the billing, accounts receivable, and rates for DEP as a central repository for all customer information. *Id.* at 71-72. She explained that CIS links the consumption and metering process to payments, collections, and other downstream processes, including additional work order requests such as service connections and disconnections, outages, and trouble requests. CIS also manages customer profiles and integration of data to provide a holistic view of the customer and it should enable expected customer capabilities. *Id.* at 72-73. Witness Hunsicker explained that DEP developed its previous CIS almost 30 years

ago and the system could not efficiently support new capabilities, and thus required complex add-ons and manual performance of some complex billing functions. *Id.* at 71.

Witness Hunsicker explained that Customer Connect benefits customers by providing a modern, configurable billing system that allows DEP to keep pace more efficiently with changing customer expectations and needs. Improvements with Customer Connect include a customer-centric data model and more holistic customer data analytics capabilities, which allow DEP to better know its customers and the usage needs across the entire Duke Energy footprint and provide a more customized experience. She explained that since she first testified to the need for Customer Connect in the 2017 Rate Case, DEP has kept stakeholders informed of the status of the implementation and that, while no complex, enterprise-wide CIS implementation is without challenges, its Customer Connect implementation benchmark metrics compare favorably to industry benchmarks. *Id.* at 72.

No party contested DEP's request to recover its costs related to Customer Connect.

Discussion and Conclusions

No parties opposed DEP's requests related to DSDR, Payment Navigator, or Customer Connect. In *State ex rel. Utils. Comm'n v. Intervenor Residents*, 305 N.C. 62, 75-77, 286 S.E.2d 770, 778-79 (1982), the North Carolina Supreme Court held that the Commission can accept the uncontested evidence of a public utility regarding the reasonableness of its costs as satisfying the utility's burden of proof on the question of cost recovery. The Commission concludes that DEP has met its burden of showing that its proposals related to DSDR, Payment Navigator, and Customer Connect are just and reasonable.

More specifically, the Commission concludes that DEP's proposal to include future DSDR program costs in base rates starting with the effective date of the rates established in this proceeding to be reasonable and appropriate. Further, the Commission concludes that DEP's requested recovery of costs associated with its Customer Connect project is just and reasonable to all parties considering the evidence presented.

Finally, the Commission approves implementation of Payment Navigator and recognizes and appreciates the work of DEP to undertake this effort during the COVID-19 pandemic and to devote resources and expertise to connecting customers with assistance during the crisis. The Commission recognizes the customer benefits that arise, particularly in the context of those customers most in need, when DEP (and its affiliates) apply their specialized knowledge and resources in direct support of the customers. The Commission encourages DEP to continue to partner with assistance agencies across its service area and to proactively contact struggling customers to direct them to contact a Payment Navigator specialist for assistance in managing their electric utility bills.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 35

COSS Stipulation

The evidence supporting this finding is in DEP's verified Application and Form E-1; the COSS Stipulation; the testimony and exhibits of DEP witness Hager, Public Staff witnesses McLawhorn and D. Williamson, and CIGFUR witness Phillips; and the entire record in this proceeding.

Summary of Evidence

DEP Direct Testimony

Cost of Service Study Overview

In her testimony, DEP witness Hager described the purpose of a cost of service study (COSS) and how costs are assigned pursuant to such study. She explained that the COSS is used to align the total costs incurred by DEP in the test period with the jurisdictions and customer classes responsible for those costs. Tr. vol. 11, 82. Using the principle of cost causation, the COSS assigns or allocates DEP's revenues, expenses, and rate base to the regulatory jurisdictions and to customer classes that caused such costs to be incurred. *Id.* Costs are first grouped according to their function. *Id.* at 84. Functions include production (generation); transmission; distribution; and customer service, billing, and sales. *Id.* Functionalized costs are then classified based on the utility operation or service being provided and the related causation of the costs. *Id.* Typical classifications include demand, energy, and customer-related costs. *Id.* Finally, the functionalized and classified costs are allocated or directly assigned to the proper jurisdiction and customer class based on the way the costs are incurred (i.e., based on cost causation principles). *Id.* at 84-85. Once all costs and revenues are assigned, the COSS identifies the return on investment that DEP has earned for each customer class during the test period, and these returns can then guide rate design. *Id.* at 83.

The COSS Stipulation

On September 13, 2022, DEP, DEC, the Public Staff, CIGFUR, and CIGFUR III (the COSS Stipulating Parties) filed the COSS Stipulation with the Commission. Tr. vol. 11, 80. The COSS Stipulation provides that production and transmission demand costs are first allocated to the North Carolina retail jurisdiction using the 12 CP method, and then production demand costs are allocated within North Carolina retail rate classes using the Modified A&E method. *Id.* Because transmission demand does not have average or excess energy components, the transmission demand factors at the customer class level are equivalent to the 12 CP calculation. *Id.* The stipulation also provides that, for purposes of allocating production demand costs on a jurisdictional basis as well as to North Carolina retail rate classes, DEP will make an adjustment to exclude certain curtailable/interruptible loads if they were not curtailed at the twelve system peak hours during the test year. *Id.* By its terms, the COSS Stipulation only applies in the current rate

case, and COSS Stipulating Parties are free to advocate for different methodologies in future DEP cases. *Id.* DEP witness Hager testified that the stipulation is reasonable and that the Commission should approve it, noting that it was the result of the give-and-take inherent in coming to a settlement among parties with diverse views on the appropriate methodologies. *Id.* at 80-81. The COSS Stipulating Parties urge the adoption of the stipulation in this case as a fair and reasonable methodology for the allocation of costs. COSS Stipulation at 4-5, Tr. Ex. vol. 7.

The 12 CP Method

Under the COSS Stipulation, the 12 CP method will be used to allocate costs to the North Carolina retail jurisdiction. COSS Stipulation at 3, Tr. Ex. vol. 7. Witness Hager testified that in its previous rate case, DEP recommended, and the Commission approved, the summer coincident peak (Summer CP) method to allocate the fixed portion of production and transmission demand-related costs. *Id.* at 89. However, DEP now believes it is appropriate to move from Summer CP to 12 CP, which utilizes the average of the test year's twelve monthly peaks. *Id.* Witness Hager testified that DEP's integrated resource planning period has shifted away from an emphasis solely on summer peaks, and that by averaging the twelve monthly peaks, the 12 CP method is less volatile than a single coincident peak. She further testified that the 12 CP method is regularly used by other utilities and has been approved by state commissions and the FERC. *Id.* at 89-90.

The Modified A&E Method

The COSS Stipulation also proposes a Modified A&E method to allocate production demand costs across North Carolina retail customer classes. COSS Stipulation at 3, Tr. Ex. vol. 7. DEP witness Hager testified that the Modified A&E method adopted under the COSS Stipulation considers that generation facilities are needed to serve a utility's "average load" as well as its "excess or peak load" in assigning responsibility for the recovery of production demand-related costs. Tr. vol. 11, 81. The excess demand is the excess of a rate class' non-coincident peak (NCP) demands over its average demands. Under this method, all groups of customers are allocated some portion of the production plant investment and fixed expenses related to the generation of power. *Id.* at 96. A rate class' coincident peak demand is the class' load at the time of the system's peak demand, while a rate class' NCP is the maximum demand regardless of the time of occurrence. *Id.* Witness Hager explained that each customer class' non-coincident demand likely occurs at different times. *Id.* She noted that the A&E method is used in several jurisdictions including at least a third of the 30 utilities she examined and is a reasonable method for allocating demand-related production costs to the North Carolina retail classes in this case. *Id.* at 156, 81. However, DEP modified the method to conform the A&E allocators to the 12 CP method used at the North Carolina retail jurisdictional level. *Id.* at 97. In response to Commissioner Clodfelter's question, witness Hager testified that this method was used by Dominion in Virginia, but has never been used by Dominion in North Carolina. *Id.* at 130. Additionally, Witness Hager testified that since the sum of NCPs exceeds the coincident system peak, the excess components for each rate class were scaled down proportionally, such that the sum of their demand

matches the coincident system peak. *Id.* at 133. In response to Commission questions, DEP witness Hager stated that DEP did not use the 12 CP method for both jurisdictional and rate class allocation for this proceeding as it did in South Carolina, a difference which Witness Hager attributed to the COSS Stipulation. *Id.* at 134.

Removal of Certain Curtailable/Interruptible Loads

DEP witness Hager testified that, historically, DEP has allocated production fixed costs based on the demands served at its peak hour. *Id.* at 97. She testified that aligning firm load with firm capacity to serve that load is more consistent with the principle of cost causation than the previous method. *Id.* at 98. DEP does not plan for, and does not purchase capacity for, the curtailable load of customers. *Id.* Since DEP can curtail customers who take interruptible service so that their load does not contribute to the system peak, interruptible load does not factor in to how much the utility must invest in capacity to meet the system peak. *Id.* If the utility curtails all possible curtailable load in the test year during system peaks, there is no need for adjustments, as revenues and loads both reflect only firm load. *Id.* However, there can be a mismatch between revenues and loads if there is some non-firm load in the test year peaks. *Id.* Accordingly, DEP has removed non-curtailed non-firm load present during the test year peaks where its presence would create a mismatch with revenues. *Id.* This adjustment ensures a matching of firm load with firm load revenues. *Id.* This practice is also consistent with FERC precedent. *Id.* Witness Hager testified that this proposed method will eliminate the volatility of having load in one test year and out in the next test year. *Id.* at 100.

Adjustments were made to remove certain curtailable load at both the North Carolina retail jurisdiction level with the 12 CP method, as well as at the North Carolina retail rate class level with the modified A&E method. *Id.* at 101. The demand-related transmission costs were allocated to rate classes based on 12 CP demand, without adjustment for curtailable load. *Id.*

Distribution Costs

DEP witness Hager testified that most distribution investments are identified and then directly assigned to the state in which they are located. *Id*. Distribution costs identified as customer-related are allocated using customer allocation factors, and the remainder are designated as demand-related and allocated to customers based on NCP demand allocators. *Id.*

NCP allocators are developed to account for the different levels of the distribution system where customers may take service. *Id.* Witness Hager explained that NCP allocators are developed by taking the ratio of the non-simultaneous peak demands of the customers in each class whenever that peak occurred during the test period and comparing that to the sum of all customers' non-simultaneous peak demands. *Id.* She noted that several different NCP allocators are developed to account for the different levels of the distribution system where customers may take service (primary, secondary, etc.). *Id.* For example, only the NCP demand of customers taking service at secondary

voltage is included in the development of the NCP allocator used to allocate secondary distribution lines and poles. *Id.* at 101-02.

Further, witness Hager testified that NCP allocators are used for demand-related distribution investment because distribution facilities serve individual neighborhoods, rural areas, or commercial districts; they do not function as a single integrated system in meeting system peak demand. *Id.* at 102. The individual distribution system serving an area must be able to meet the peak demand in the area it serves, whenever the peak occurs. *Id.* Accordingly, Witness Hager testified that contribution to NCP is the appropriate measure of determining customers' responsibility for costs, because it best measures the factors that drive investment to support that part of the system. *Id.*

Energy Allocators

DEP witness Hager testified that energy-related costs, such as fuel costs and variable production costs at generating stations, reflect the variable cost of producing, transmitting, and delivering electricity. *Id.* at 102. She testified that these costs are allocated using DEP's kWh of generation and deliveries during the test period. *Id.* Witness Hager explained that kWh sales information is collected and adjusted for the level of losses attributable to each class and jurisdiction to determine the level of kWh at the generator attributable to that class or jurisdiction. *Id.*

Customer Allocators

DEP included operating expenses in FERC accounts 901-917 for allocation as customer-related costs that include meter reading, billing and collection, and customer information and services. Tr. vol. 11, 103. DEP has also included in this category a portion of distribution costs that it has identified as customer-related, such as meters and service drops (FERC accounts 369 and 370) and a portion of transformers (FERC account 368). *Id.* A portion of costs for distribution lines and poles (FERC accounts 364-367) were also identified as customer related. *Id.* The remaining distribution plant and associated costs were classified as demand-related, except for FERC account 363, Energy Storage Equipment – Distribution. *Id.*

Account 363, beginning in 2020, had a small balance of approximately $11 million related to batteries. *Id.* DEP witness Hager testified that storage battery equipment functionalized to distribution (FERC account 363) is allocated across customer classes using gross distribution plant excluding batteries. *Id.* This approach recognizes that batteries provide benefits to or support different parts of the distribution system. *Id.*

Witness Hager testified that a portion of distribution costs related to FERC accounts 364-68, including costs of poles, towers, fixtures, overhead and underground conductors, and transformers, are customer-related. *Id.* at 104. NARUC discusses using two methods for allocating these customer-related distribution costs: the Minimum System Method and the Zero-Intercept Method. *Id.* Witness Hager testified that both methods recognize that some portion of the distribution system is necessary to serve customers, regardless of whether the

customers take any energy from the system. *Id.* The Minimum System Method seeks to determine the minimum size distribution system that can be built to serve the minimum load requirements of customers. *Id.* This method develops the cost of the minimum set of distribution assets that are needed to serve customers, and allocates those costs based on the number of customers. *Id.* The Zero-Intercept Method, according to witness Hager, similarly allocates a portion of the same distribution accounts on the basis of the number of customers and seeks to identify the portion of distribution plant that is associated with no load using regression techniques. *Id.*

Witness Hager testified that DEP incorporated the Minimum System Method into its COSS and testified that this was appropriate for the allocation of customer-related distribution costs. *Id.* at 105. She explained that the Zero-Intercept Method is a more complex and time-consuming methodology. Witness Hager further explained that the Minimum System Method, which is sound and consistent with cost causation, produces results that are not materially different from the Zero-Intercept Method. *Id.* DEP's Minimum System Study allowed DEP to classify the distribution system into customer-related and demand-related portions. *Id.* She testified that because every customer requires some minimum amount of wires, poles, and other distribution infrastructure, every customer "causes" DEP to install some amount of distribution assets. *Id.* The concept used by DEP in developing its Minimum System study was to consider what distribution assets would be required if every customer had only a minimum level of usage. *Id.* This allows DEP to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer. *Id.* Once minimum system costs are identified, distribution costs over this amount and direct assignments of those extra costs are determined to be driven by demand. *Id.*

Witness Hager testified that the PBR Statute requires the use of the minimum system methodology to allocate distribution costs between customer classes. *Id.* at 106.

The Public Staff Testimony

Public Staff witness McLawhorn testified in support of the COSS Stipulation and discussed the stakeholder process that led to that settlement. Witness McLawhorn discussed the Commission's March 31, 2021, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice issued in Docket No. E-7, Sub 1214, in which the Commission adopted the Second Agreement and Stipulation of Partial Settlement (Sub 1214 Partial Settlement). Tr. vol. 16, 398-99. The Sub 1214 Partial Settlement provided for an analysis of various cost of service methodologies in which DEP and DEC agreed to consult with the Public Staff and interested parties to analyze and develop cost of service studies based upon specific criteria, including the analysis of the various strengths and weaknesses of each respective methodology, and to file the resulting COSS with the Commission before DEP filed its next rate case. *Id.* at 399. As witness McLawhorn described, the stakeholders met several times throughout 2021, holding the final meeting on November 16, 2021. *Id.* On January 25, 2022, DEP and DEC filed the results of the COSS in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214, as the Commission required. *Id.* at 400. Although the stakeholder process did not result in a consensus as to the appropriate cost of service allocation methodology to

utilize, it helped certain parties arrive at the COSS Stipulation that is before the Commission in this case. *Id.*

Public Staff witness D. Williamson also testified in support of the COSS Stipulation, including the results of his investigation on how the COSS influences the way DEP's base rate charges will reflect the requested revenue requirement changes. Tr. vol. 20, 133. As witness D. Williamson explained, it is important that the utility consider all costs in the COSS to ensure that it is reasonably able to recover its full cost to serve all customers, while also ensuring that all jurisdictions and customer classes bear the appropriate responsibility for the respective costs they impose upon the system. *Id.* at 149-50. In discussing the 12 CP methodology for jurisdictional allocations and the modified A&E methodology for NC retail allocations, witness D. Williamson confirmed that the use of different cost of service allocation methodologies may be unusual for a general rate case in North Carolina, but use of two methodologies does occur in some other jurisdictions. *Id.* at 152. In sum, witness D. Williamson recommended approval of the COSS Stipulation and DEP's use of the methodologies to which the parties agreed in the COSS Stipulation. *Id.* at 180.

CIGFUR Testimony

CIGFUR witness Phillips filed testimony in support of the COSS Stipulation. Witness Phillips testified that the COSS Stipulation is reasonable and that the Commission should approve it in its entirety. Tr. vol. 21, 477. Witness Phillips also testified that both the 12 CP and modified A&E methodologies are theoretically sound, reflect principles of cost causation as required by N.C.G.S. § 62-133.16(a)(1) and (b), and should be used for ratemaking in this proceeding. *Id.* at 474, 477. Witness Phillips further testified that DEP has appropriately allocated distribution system costs to customer classes in a manner consistent with N.C.G.S. 62-133.16(b), which requires the use of minimum system methodology by an electric public utility for the purpose of allocating distribution costs. *Id.* at 473. Witness Philips additionally testified about the relation between the excess component of the A&E method as it relates to additional capacity requirements. *Id.* at 479.

CUCA Testimony

CUCA is not a party to the COSS Stipulation. CUCA witness O'Donnell acknowledged that such settlements are a product of give-and-take settlement negotiations. Tr. vol. 21, 648. Despite this, witness O'Donnell testified that the results of any model should be viewed considering the economic impact that DEP rate increases will have on the economic drivers in North Carolina. *Id.* Witness O'Donnell recommended that if the Commission were to accept the modified A&E cost allocation method, then the Commission should set rates with the recognition that North Carolina is losing manufacturing jobs more than other southern states. *Id.* at 652-53. Witness O'Donnell questioned whether the time is right for DEP to transition to full implementation of the A&E method. *Id.* at 653. Nevertheless, he testified that CUCA does not oppose the COSS Stipulation. *Id.* at 648.

The Commercial Group Testimony

The Commercial Group is not a party to the COSS Stipulation. However, Commercial Group witness Chriss testified that for the purposes of this rate case, the Commercial Group does not oppose DEP's proposed production capacity cost allocation methodology. Tr. vol. 21, 520.

North Carolina League of Municipalities (NCLM)

The NCLM was the only party to cross-examine DEP witness Hager during the expert witness hearing on May 8, 2023. Tr. vol. 11, 113-58. NCLM questioned witness Hager as to whether a 20.0% increase in lighting rates in year one of the MYRP would be considered a "gradual" change. *Id.* at 117-20. In response, witness Hager testified that, while the change in cost of service methodology did lead to DEP's allocating more cost to the Lighting class, only a portion of that increase was driven by the change in cost of service methodology. *Id.* at 119. She also testified that the point of a cost of service study is to determine allocation of costs to customer classes, but that rate design ultimately uses the cost of service study to determine rates for customers. *Id.* at 120. Witness Hager acknowledged that this COSS allocates more costs to lighting. *Id.* at 119. But she also testified that this is reasonable because the COSS determined that this increase was consistent with cost causation principles, meaning that lighting customers are causing more costs to be incurred on the system. *Id.* at 120.

Further, NCLM questioned whether all parties participated in the COSS collaborative and in settlement discussions. *Id.* at 121-22. Witness Hager testified that DEP invited all entities that were parties to the previous rate case to participate in the COSS collaborative that led to settlement discussions, which then led to the COSS DEP uses in this case. *Id.* at 122. NCLM was a party to the prior case but did not participate in the COSS collaborative and did not offer any alternative cost of service methodology in this rate case.

Discussion and Conclusions

Although the COSS Stipulation is not unanimous, no other party to this proceeding has proposed an alternative cost of service methodology. Tr. vol. 11, 125.

Based upon the evidence presented in this case, including the evidence offered in support of the stipulation as well as the evidence elicited through cross-examination as discussed hereinabove, the Commission approves the COSS Stipulation. The Commission notes that the use of the diversified non-coincident peak demand to calculate the excess allocation portion of the Modified A&E methodology is a departure from both the method approved currently for DEP as well as the A&E method applied in South Carolina. Therefore, the Commission directs DEP to provide a more detailed justification for the use of a NCP demand over a coincident peak demand for any cost allocation purpose in future rate cases.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

TCA Stipulation

The evidence supporting this finding of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Abernathy and Bateman and Public Staff witness Metz; the TCA Stipulation; and the entire record in this proceeding.

As explained by DEP witness Maley, the Red Zone Expansion Plan transmission projects (RZEP Projects) included in DEP's MYRP consist of transmission upgrades needed to enable interconnection of additional solar generation on the DEP transmission system. DEP witness Abernathy testified as to the revenue requirement sought by DEP for the RZEP Projects, which involved allocation of all RZEP costs to DEP. In light of concerns expressed by the Public Staff in the Carbon Plan proceeding regarding the imbalance of transmission costs being incurred between DEC and DEP associated with the interconnection of new generation, DEP presented (but did not propose) an alternative allocation of RZEP costs as between DEC and DEP based on respective retail transmission demand load ratio share. Tr. vol. 13, 99-101. Witness Abernathy testified that DEP did not support this allocation but included the calculation in the event the Commission determined that such an allocation was more appropriate in light of the concerns of the Public Staff. *Id.* at 102.

While the Public Staff found merit in DEP's alternative proposal, Public Staff witness Metz recommended a different proposal that focused on the net energy transfers between DEP and DEC. Tr. vol. 16, 454-55. DEP witness Metz explained that the Public Staff's alternative proposal utilizes the non-firm transmission rate from the FERC-approved OATT of DEC, Duke Energy Florida, LLC (Duke Energy Florida), and DEP, which incorporates capital and ongoing O&M costs of the DEC and DEP transmission systems. He testified that DEP's alternative allocation only considers a discrete portion of each utility's system and does not consider the O&M costs. The OATT, updated annually and listed on the OASIS website, provides an established calculation for transmission system capital and O&M costs that is transparent and easily verifiable. *Id.*

DEP and the Public Staff resolved their differences on this issue and, as set forth in the TCA Stipulation, agreed to a pro forma adjustment of approximately $20 million to increase the revenue requirement in the DEC Rate Case and a corresponding decrease the revenue requirement in the instant proceeding.

DEC, also a party to the stipulation, DEP, and the Public Staff agreed to calculate the pro forma amount of transmission expense for DEC and transmission revenue for DEP by multiplying the net transfers from DEP to DEC under the JDA in 2022 by the DEP non-firm transmission rate from the FERC-approved Joint OATT of DEP, DEC and Duke Energy Florida. The stipulation makes clear that the adjustment is for North Carolina ratemaking purposes only and will neither change the terms or conditions of the JDA nor result in any accounting entries for DEP or DEC. The TCA Stipulation provides that the

adjustment will become effective on October 31, 2023, for both DEP and DEC and will terminate at the sooner of the effective date of rates in DEP's or DEC's next general rate case or the effective date of a full merger of DEP and DEC, unless the Commission orders otherwise. TCA Stipulation § II, Tr. vol. 7, 23.

DEP witness Bateman testified in support of the TCA Stipulation. Tr. vol. 14, 146. She testified that the TCA Stipulation is the result of substantial discovery and extensive negotiation among the stipulating parties and that it reflects a constructive near-term approach to addressing rate disparity concerns arising from the increasing net energy transfers from DEP to DEC under the JDA. *Id.* Public Staff witness Metz also testified in support of the TCA Stipulation. Tr. vol. 16, 517-18. Witness Metz testified that the TCA Stipulation addresses the growing level of net energy transfers and the subsequent rate disparity between DEP and DEC in North Carolina and explained that the adjustment will compensate DEP and DEC ratepayers for the use and annual maintenance of each utility's transmission system for energy transfers under the JDA. *Id.*

The Commission concludes that the TCA Stipulation itself, along with the expert testimony discussed above, is credible evidence and is entitled to substantial weight in the Commission's ultimate determination on this issue. No party offered evidence opposing the TCA Stipulation, and the Commission concludes that the TCA Stipulation, as supported by the testimony cited above, establishes a reasonable method to align costs with cost causation principles. Utilization of this method appropriately balances DEC and DEP benefits to the least cost dispatch of their respective systems. Accordingly, the Commission concludes that the provisions of the TCA Stipulation are in the public interest and are just and reasonable to all parties in this proceeding. Therefore, the TCA Stipulation is approved for the purposes of DEP's Application in this proceeding. The Commission notes that all parties have an opportunity in the pending DEC PBR proceeding in Docket No. E-7, Sub 1276 to address the DEC impacts of the TCA Stipulation before the Commission addresses the TCA Stipulation in that proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS FOR FACT NOS. 37-38

PIMs Stipulation

The evidence supporting these findings and conclusions is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Bateman and Stillman, Public Staff witnesses D. Williamson and Thomas, AGO witness Nelson, and CIGFUR witnesses Phillips and Gorman; the PIMs Stipulation; and the entire record in this proceeding.

PIMs

DEP initially proposed the following PIMs in its Application: (1) Peak Load Reduction, (2) Low-Income/Affordability, (3) Reliability, and (4) Renewables Integration and Encouragement. Tr. vol. 14, 91-99.

As filed, the Peak Load Reduction PIM encouraged DEP to reduce peak load, based on the estimated winter peak kilowatt reduction resulting from new customer enrollment in DEP's dynamic and time differentiated rate programs. *Id.*

The Low-Income/Affordability PIM provided incentives for DEP to encourage voluntary contributions to its existing "Share the Light" Fund, which provides financial assistance to customers who are struggling to pay their energy bills, through a structure that establishes graduated shareholder contributions and shareholder bonus matching contributions to fund health and safety repairs for low-income residences based upon target levels of contributions to the Share the Light Fund. *Id.*

The Reliability PIM held DEP accountable to maintain service reliability as measured by SAIDI (excluding Major Event Days (MEDs)). This PIM features graduated penalties DEP shall distribute to customers for failure to maintain SAIDI below tiered threshold levels that DEP will base upon historic averages adjusted for statistical confidence levels and increased outages due to additional grid work that DEP expects during the MYRP. *Id*.

The Renewables Integration and Encouragement PIM involved three metrics to incent and reward DEP. The Distributed Energy Resource (DER) Integration Metric A provided graduated rewards to DEP for exceeding targets for the number of net-metered DER customers interconnected to the DEP system. *Id.* at 104. The Large Customer Renewable Program Encouragement Metric B provided an incentive for DEP to design, obtain approval of, and subscribe customers to new renewable programs that meet these customers' desires for access to clean energy resources. *Id.* at 106. The Residential Customer Shared Solar Program Encouragement Metric C encouraged DEP to subscribe residential customers to new shared solar programs. *Id.* at 107.

In addition to the PIMs, DEP also proposed three tracking metrics in the areas of customer service, carbon dioxide (CO2) emissions, and beneficial electrification. The proposed customer service tracking metric supported maintaining adequate levels of customer service per N.C.G.S. § 62-133.16(d)(2)j. *Id*. at 113. The proposed CO2 emissions tracking metric would report progress towards compliance with the CO2 reduction requirements of S.L. 2021-165 and the Carbon Plan. *Id.* at 113-14. Finally, the third metric proposed to report on incremental load from EVs. *Id.* at 114.

Public Staff witnesses D. Williamson and Thomas expressed concerns with each PIM, beginning with the metric DEP proposed in the Peak Load Reduction PIM. Tr. vol. 18, 390. The Public Staff testified that time of use (TOU) customers have complete control over whether they act on price signals and shift their load, and enrollment in TOU rates does not directly correlate to winter peak load reductions across DEP's footprint. The Public Staff notes that DEP's TOU report suggests a modest winter peak load reduction for customers who could be presumed to be early adopters or have a greater awareness of energy usage, but there is no guarantee that this level of winter peak load reductions will occur with greater enrollment. *Id.* at 390. The Public Staff also testified that, as DEP is already receiving a performance incentive for its DSM and EE programs through its

DSM/EE rider, a winter peak load reduction PIM should have to demonstrate incrementally greater savings above those being observed through DSM and EE programs, particularly for customers who are on TOU rates and participate in DSM or EE programs. *Id.* at 391.

The Public Staff expressed concerns regarding the Low-Income/Affordability PIM, primarily based on the fact that the Share the Light Fund is not a regulated activity, and the impacts of this PIM would not be reflected in the annual PIM rider. The Public Staff testified that while customer contributions are an input in the calculation of this PIM, shareholders presently have great discretion to adjust the amount of their overall contributions to the Share the Light Fund. *Id.* at 392.

Regarding the Reliability PIM, which targets reliability by tracking DEP's SAIDI score, the Public Staff expressed concern that because benchmarking for the tiered performance structure proposed by DEP is based on five years of historical SAIDI data, consideration of any expected advancements in reliability that will occur as a result of grid investments included in the proposed MYRP is foreclosed. In addition, the Public Staff expressed the concern that the five years of historical performance data includes data that were collected before DEP's GIP investments were placed into service. *Id.* at 393.

Finally, the Public Staff testified as to concerns with the Renewables Integration and Encouragement PIM. *Id.* at 394-96. With respect to Metric A, the Public Staff testified that Net Energy Metering (NEM) adoption is largely outside of DEP's control, that NEM adoption has been steadily increasing over time as individual customers make individual financial decisions, that two recent Commission orders that have not been incorporated into the forecast or financial structure of this proposed PIM that have the potential to skew the adoption rates above what DEP has already forecast, and that the new NEM rate schedules involve customer enrollment in certain TOU rates, which links this metric to the Peak Load Reduction PIM. *Id.* at 394-96. With respect to Metrics B and C, the Public Staff expressed concerns that DEP has complete control over all renewable program capacity available to large customers and that a capacity limit that is set below anticipated enrollment requests could result in DEP easily surpassing the enrollment thresholds. Additionally, the Public Staff testified that existing large customer programs have been popular without an incentive, and the Public Staff noted that performance data on which Metric B and Metric C are based are linked to new programs and there is therefore insufficient data for determining whether a financial incentive is necessary. *Id.* at 396.

In light of the Public Staff's concerns, the Public Staff proposed three modified PIMs in response to the PIMs DEP proposed. The Public Staff proposed a Time-Of-Use Enrollment PIM, a Customer Reliability PIM, and a Renewable Interconnections PIM, which involve both modifications to DEP proposals as well as new proposals. *Id*. at 396-97.

In response to DEP's proposed Low-Income/Affordability PIM, NCJC, et al. witness Howat and Sierra Club witness Colton expressed concerns with the effectiveness of the proposed PIM as designed in advancing a policy goal of low-income energy affordability.

Id. at 205, 252. Both witnesses filed a suggestion to include a tier structure under this PIM for consideration. *Id.* at 211.

CIGFUR witness Gorman's direct testimony expressed concern regarding DEP's proposed Reliability PIM. Tr. vol. 21, 459. Witness Gorman proposed expanding the PIM to include a metric for measuring and ensuring the maintenance of adequate power quality and the avoidance of power quality incidents. *Id.* Commercial Group witness Chriss raised similar concerns about the Reliability PIM, stating that DEP should restructure the PIM to hold itself accountable for poorly performing circuits. *Id.* at 509.

AGO witness Nelson proposed a Carbon Reduction PIM as an alternative to Metrics B and C of the Renewables and Integration PIM. *Id.* at 165. Witness Nelson expressed concern that the PIMs Stipulation does not incentivize DEP to lower emissions at least cost. *Id*. at 90. DEP witness Stillman and Public Staff witness Thomas expressed concerns with a Carbon Reduction PIM's compatibility with S.L. 2021-165. *Id.* at 435, 468-69; Tr. vol. 23, 209-11.

CUCA witness O'Donnell and NCJC, et al. witness Posner proposed conceptual fuel cost PIMs. Tr. vol. 21, 671, 1104. Witness O'Donnell's proposed fuel cost PIM would attempt to manage fuel costs and volatility and encourage selection of generation resources based on fuel costs. *Id*. at 671.

DEP witnesses Bateman and Stillman explained how the carbon reduction requirement in N.C.G.S. § 62-110.9 is an aggregate requirement on DEC and DEP, meaning that the law does not require DEP to independently reduce its CO2 emissions by 70.0%. *Id.* at 211.

DEP, the Public Staff, and CIGFUR resolved their differences of opinions on PIMs proposed in this proceeding in the PIMs Stipulation. PIMS Stipulation, Tr. vol. 7, 23.

DEP's PBR Policy Panel provided testimony in support of the PIMs Stipulation. Tr. vol. 14, 131. The PBR Policy Panel testified that the resolution reached represents a balanced approach to achieving policy goals in DEP's first PBR Application. Tr. vol. 15, 17, 70. DEP witness Stillman testified as to how the settled PIMs originated from the North Carolina Energy Regulatory Process (NERP) PBR Working Group, were informed by DEP's prefiling PIM stakeholder process, and evolved over discussions with the stipulating parties. Tr. vol. 14, 132-33. DEP witness Bateman testified that the Commission must examine DEP's PIMs proposals in the context of the entire MYRP. Tr. vol. 15, 15. Witness Bateman testified that DEP took a conservative approach in its first PBR Application so that DEP, customers, and the Commission could gain experience with the operation and implementation of PIMs. *Id.* at 69. DEP witness Stillman explained DEP's approach to designing the PIMs around the 1.0% cap in N.C.G.S. § 62-133.16 and stated that DEP deliberately chose only a select number of PIMs that meet the maximum number of policy goals. *Id.* at 65.

Public Staff witnesses D. Williamson and Thomas also provided testimony in support of the PIMs Stipulation. Tr. vol. 18, 424-25. Witnesses D. Williamson and Thomas testified that the PIMs Stipulation benefits ratepayers by providing improved compliance with N.C.G.S. § 62-133.16 and that each PIM in the stipulation appropriately targets a specific policy goal from N.C.G.S. § 62-133.16. They further testified that the PIMs Stipulation will benefit ratepayers through improved operational efficiencies, cost savings, and reliability of electric service over the course of the MYRP. *Id*.

The parties to the PIMs Stipulation did not achieve an agreement on the Low Income/Affordability PIM. The PIMs Stipulation includes the three PIMs described below; the PIMs are described with specificity, including thresholds, tiers, penalty and reward amounts, and projections of costs in PBR Policy Panel Settlement Exhibits 1, 3, and 4. Tr. Ex. vol. 14.

Time Differentiated and Dynamic Rate Enrollment PIM

DEP Witness Stillman testified that the Peak Load Reduction PIM was renamed as the Time Differentiated and Dynamic Rate Enrollment PIM (TOU Enrollment PIM) and was revised to provide DEP with a $5 incentive for every new customer enrolled in an eligible program. Tr. vol. 14, 135. Witness Stillman testified that this PIM targets and advances operational efficiency and cost savings and encourages DEP to design and seek approval of dynamic and time-differentiated rate designs. *Id*. at 93. Witness Stillman further testified that this PIM is an upside only PIM, with a shared savings-like structure that would distribute 30.0% of the total peak reduction joint benefit to DEP and 70.0% to customers. *Id.* at 135.

At the expert witness hearing, witness Stillman further explained that the purpose behind this PIM is to encourage DEP to develop and expand the use of TOU rates to help address peak load growth. *Id.* at 169-71. This PIM should encourage customers to adapt to new rate designs and subsequently shift their usage from high to low usage periods. *Id.* at 169. Witness Stillman testified that current subscribership to these programs is low, in the range of about 1.5% of residential customers, so one of the purposes behind this PIM is to encourage more customers to subscribe to TOU programs. *Id.* at 171. Witness Stillman also stated that DEP had statistically significant results demonstrating that customers that have participated in these rate designs have adapted and shifted their usage from on peak periods to off peak periods. *Id.* at 170. In response to concerns about insufficient data to measure impact on load due to enrollment in TOU programs, witness Stillman testified that the PIMs Stipulation addresses this concern and explained that DEP will conduct a broader Evaluation, Measurement, and Verification study on system benefits once there is sufficient participation in DEP's TOU rate schedules to achieve statistical significance. Tr. vol. 15, 38-39.

Public Staff witnesses Thomas and D. Williamson testified that the parties designed the TOU Enrollment PIM to increase the customer base subscribing to TOU rates to continue to ascertain how TOU rates impact load reduction. Tr. vol. 18, 459. Witness D. Williamson explained that it is appropriate to reward DEP for increasing the

number of TOU customers to mitigate energy usage during peak periods when the grid is stressed, so that DEP can better operate and improve operational efficiencies of the grid. *Id.* at 460. Witness Thomas also explained that the parties based the $5 per customer reward amount on savings per customer from a previously conducted TOU Report. *Id.*

Reliability PIM

DEP witness Stillman offered direct settlement testimony in support of DEP's Reliability PIM, which is designed to facilitate maintaining or improving service reliability in compliance with N.C.G.S. § 62-110.9(3). Tr. vol. 14, 136-37. DEP's Reliability PIM would be measured by SAIDI, excluding MEDS. As originally proposed, DEP's Reliability PIM provided for graduated penalties based on DEP's failure to maintain SAIDI below certain threshold tiers based upon five-year historic averages, adjusted for statistical confidence levels, and increased outages due to expected grid work. Tr. vol. 14, 91-92.

At the expert witness hearing, witness Stillman explained that as part of the PIMs Stipulation, DEP agreed to revise the metric for this PIM to account for projected SAIDI improvement during the MYRP period due to expected grid investments. Tr. vol. 15, 41-43.

Renewables Integration and Encouragement PIM

DEP witness Stillman testified that DEP designed Metric A of the Renewables Integration and Encouragement PIM to incent rooftop solar and to provide DEP with an incentive to determine the most effective way to encourage adoption. Tr. vol. 15, 53. This metric was modified as part of the PIMs Stipulation to base the incentive tiers on the three-year rolling average of net metered interconnections. Tr. vol. 23, 194-95. Metric A would provide an incentive of up to $4 million to DEP if the number of net metered interconnections for each rate year exceeds the applicable preceding three-year rolling average by at least 25.0%. Tr. vol. 15, 50.

DEP witness Stillman testified at the expert witness hearing that the only difference between Metric B as proposed by DEP and the PIMs Stipulation is a decrease in the reward amount. Tr. vol. 15, 57. As filed, Metric B of the Renewables Integration and Encouragement PIM supports large commercial and industrial (C&I) customers, educational institutions, and local governments who have corporate goals related to electricity and are increasingly seeking access to renewable energy and programs. Tr. vol. 14, 106; Tr. vol. 23, 195-96. As witness Stillman explained, this component of the Renewables Integration and Encouragement PIM was proposed in response to feedback received from large customer representatives. Tr. vol. 14, 138; Tr. vol. 21, 460-61; *See* CIGFUR witness Gorman Direct Ex. 7; Tr. Ex. vol. 21. Public Staff witness Thomas testified that the reduction in the reward amount for Metric B, considering the PIMs Stipulation as a whole, helped to alleviate the Public Staff's concerns that DEP would be overly rewarded for the independent financial decisions of large commercial and industrial customers. Tr. vol. 18, 466-67.

Revised Metric C of the Renewables Integration and Encouragement PIM in the PIMs Stipulation is based on the recommendations of the Public Staff, addresses utility-scale interconnections, and is designed to increase operational efficiency by incentivizing interconnections above DEP's estimated annual limits. Tr. vol. 14, 139. This component includes incentive tiers and minimum MW thresholds for utility-scale interconnections in each MYRP rate year. *Id*. at 139. DEP witness Stillman testified that Metric C responds to recommendations from the Public Staff to develop a PIM to incentivize DEP to focus on utility-scale interconnections. Tr. vol. 15, 60. He further stated that the reward will not be possible until DEP exceeds the interconnections the Carbon Plan already required under the Carbon Plan. *Id*. at 63. The Public Staff also testified that the intent of Metric C is to incent DEP to be more efficient in the interconnection process. Tr. vol. 18, 472.

Tracking Metrics

DEP witness Stillman provided direct testimony stating that DEP selected the tracking metrics it proposed to quantitatively measure and monitor outcomes and/or utility performance that, although not tied to financial incentives or penalties, address DEP's progress in furthering important policy goals. He further stated that tracking metrics can provide useful information in evaluating potential future PIMs. Tr. vol. 14, 113-14.

In the PIMs Stipulation, the stipulating parties agreed to three tracking metrics. The first agreed-upon tracking metric is the proposed metric on customer service as DEP proposed in its initial testimony. DEP witness Stillman testified that under the customer service tracking metric DEP will provide a quarterly update during the rate year of the rolling 12-month call center answer rate and the average speed of answer. Tr. vol. 14, 140-41. Witness Stillman testified that this tracking metric is appropriate because customers often communicate with DEP about service and billing issues by telephone, it allows greater public access to the data, and it supports maintaining adequate levels of customer service. *Id.*

The second tracking metric is the proposed metric on beneficial electrification of EVs as DEP initially proposed. Witness Stillman explained that this metric requires DEP to report beneficial electrification from estimated incremental load from EVs and will provide data in an area of material public policy interest. *Id.*

The third tracking metric the PIMs Stipulation includes requires DEP to report the 10 worst performing circuits on an annual basis, including an analysis of the cause of each circuit's performance. DEP witness Stillman testified that the stipulating parties have agreed to confer on a definition for the metric for a worst performing circuit and file an update with the Commission on an agreed-upon metric no later than 60 days after issuance of the Commission's order in this proceeding. Tr. vol. 14, 141. Witness Stillman explained that the stipulating parties included this tracking metric in the PIMs Stipulation due to the importance of reliability and the information this reporting will provide to interested parties. Tr. vol. 15, 43.

Discussion and Conclusions

Upon review of the testimony of DEP, the Public Staff, and CIGFUR witnesses regarding the PIMs Stipulation, the Commission concludes that the PIMs Stipulation is the product of give-and-take negotiations between DEP, CIGFUR, and the Public Staff to achieve PIMs and metrics that are consistent with N.C.G.S. § 62-133.16 and strike an appropriate balance.

The Commission must give full consideration to a non-unanimous stipulation itself, along with all evidence presented by non-stipulating parties in determining whether the stipulation's provisions should be accepted. *CUCA I*, 348 N.C. at 466; *CUCA II*, 351 N.C. at 231. The Commission has considered the testimony of the parties to this proceeding on the PIMs, as cited above, and notes that some of the non-stipulating parties' recommendations and modifications are addressed by the PIMs Stipulation. For example, with the inclusion of the worst-performing-circuit tracking metric, certain intervenor recommendations on reliability PIMs are accounted for outside of an express PIM, and data on reliability and circuit performance will be gathered as a result. PIMS Stipulation § III.2, Tr. Ex. vol. 7.

As this is the first PBR application considered by the Commission and, therefore, the first set of PIMs to be adopted, the Commission concludes that it is reasonable and appropriate to take measured steps to implement PIMs and tracking metrics as allowed for under N.C.G.S. § 62-133.16. The PIMs and the tracking metrics set forth in the PIMs Stipulation achieve this measured approach and are balanced, reasonable, and consistent with the requirements of the PBR Statute, encourage behavior that is sought by customers, and could provide meaningful operational and financial benefits to customers. Therefore, the Commission concludes that the PIMs Stipulation is entitled to substantial weight. Accordingly, the Commission concludes that the PIMs and tracking metrics set forth in the PIMs Stipulation should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 39

Power Quality Stipulation

The evidence supporting this finding of fact is in the direct testimony of DEP witnesses Stillman and Guyton; the supplemental direct testimony of CIGFUR witness Phillips in support of partial settlement; the Power Quality Stipulation; and the entire record in this proceeding.

The Power Quality Stipulation provides that DEP and CIGFUR will work together to identify up to 13 industrial customer premises with DEP-owned transmission to distribution retail substations that DEP exclusively or primarily dedicates to the respective CIGFUR member (Eligible Premises). Subject to a feasibility review, DEP will install power quality monitoring technology for each Eligible Premises and meet with the identified CIGFUR members at least once annually to review the data from the power quality monitoring technology. Power Quality Stipulation at 3; Tr. Ex. vol. 7.

In support of the Power Quality Stipulation, CIGFUR witness Phillips testified that the stipulation will help satisfy the requirement of N.C.G.S. § 62-110.9 to maintain or improve reliability as utilities implement the Carbon Plan. Tr. vol. 21, 495. Witness Phillips testified that the Commission has recognized the well-documented reliability risks that inverter-based resources pose. *Id*. at 496-97.

Witness Phillips further testified that the pilot program the parties outline in the Power Quality Stipulation will allow DEP to mitigate the reliability risks associated with inverter-based resources. *Id*. at 497-98. Specifically, it would allow DEP to: (1) proactively monitor power quality as utilities implement the Carbon Plan; (2) gather and share data analytics with the Public Staff and the Commission; (3) determine whether power quality incidents are the result of an individual circuit or customer problem, or potentially part of a larger trend; (4) diagnose potential power quality issues and, pursuant to review, implement solutions to address any such issues; and (5) take a proactive approach to customer service and service quality. *Id.*

With respect to the cost of the pilot program, DEP witness Stillman stated in cross examination that the Power Quality Stipulation does not set a cost cap. Tr. vol. 15, 76. He estimated that the cost of installing the power quality monitoring technology would be approximately $10,000 to $25,000 per meter, while the total number of meters needed for this pilot was not specified. *Id.* at 75. He further stated that the cost of implementing solutions, as contemplated in the Power Quality Stipulation, will depend on the cause of the specific power quality issue for each premises. He added that the lessons learned from the pilot program will help the whole system, because the more meters that are installed, the more DEP will learn about where the power quality issues are arising. In acknowledging that DEP intends to seek cost recovery on a cost of service basis, witness Stillman stated in direct testimony that the pilot program will help DEP to understand the system and power quality issues better, and that it will ultimately be to the benefit of all customers. Tr. vol. 21, 474-76.

The Commission notes that no party introduced evidence in this docket suggesting that industrial customers are experiencing degraded power quality issues due to inverter-based resources. In addition, the Commission notes that the pilot program as the parties propose in the Power Quality Stipulation would be available for participation to only 13 CIGFUR members, and that DEP would recover the costs, with no cost cap, on a cost of service basis from all DEP ratepayers. This method would result in the cross subsidization of these industrial customers by all ratepayers, including residential customers.

The Commission acknowledges the effort required to craft a pilot program and a mutually agreeable stipulation. A well-designed pilot program focused on improving power quality for individual customers and for the entire system has merit and could provide benefits for all ratepayers. It is premature, based on the information provided in the Power Quality Stipulation, for the Commission to approve the pilot program as contemplated between the two parties absent additional details, including information regarding parameters for a feasibility review, participant eligibility, and cost, and absent an opportunity for interested parties to undertake a thorough review of the proposal and

provide comments to the Commission. Particularly with respect to pilot programs, the Commission needs sufficient information to ensure that the program is properly scoped and bounded. The Commission therefore concludes that the record evidence does not support approval of the power quality pilot program.

However, DEP may file an application for a power quality pilot program with the Commission in a new docket that addresses the concerns noted by the Commission, should it so choose.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 40-41

Affordability Stipulation/CAP

The evidence supporting these findings of fact is in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Harris, Bateman, and Stillman, Public Staff witnesses D. Williamson and Thomas, NCJC, et al. witnesses Howat and Posner, and Sierra Club witness Colton; the Affordability Stipulation; and the entire record in this proceeding.

Summary of Evidence

Low-Income/Affordability PIM

DEP's PBR Policy Panel testified in support of DEP's proposed Low-Income/Affordability PIM. Tr. vol. 14, 91. The PBR Policy Panel testified that the Low-Income/Affordability PIM would: (1) target and advance cost savings; (2) reduce low-income energy burdens; and (3) encourage carbon reductions. *Id.* at 94. The PBR Policy Panel testified that the proposed PIM would advance the identified policy goals by providing DEP with an incentive to promote voluntary contributions to the Share the Light Fund. *Id.* at 101.

Public Staff witnesses Thomas and D. Williamson recommended that the Commission deny DEP's proposed Low-Income/Affordability PIM. Tr. vol. 18, 418. The Public Staff expressed concern that the PIM fails to meet some of the Public Staff's guiding principles for the development of PIMs because the Share the Light Fund is not a regulated Company activity and DEP's annual PIM rider would not reflect the impacts of the PIM. *Id.* at 392.

Sierra Club witness Colton recommended that the Commission reject DEP's proposed Low Income/Affordability PIM and adopt Sierra Club's alternative proposal. Witness Colton expressed concerns that DEP's proposed Low-Income/Affordability PIM would insufficiently measure and promote the advancement of the PIM's stated goals and was not adequately in DEP's direct control. *Id.* at 295-300, 313. Alternatively, Sierra Club witness Colton recommended that the Commission require DEP to adopt a series of "outcome" metrics to measure DEP's performance and the accomplishment of program objectives. *Id.* at 293.

NCJC, et al. witness Howat recommended that the Commission reject DEPs Low-Income/Affordability PIM given his concerns that the originally proposed Share the Light Fund contributions would not directly advance low-income energy burden reductions and that there was no explicit commitment to measure potential low-income energy burden reductions attributable to the Low-Income/Affordability PIM. Witness Howat instead recommended that the Commission direct DEP to implement an alternative Energy Burden Reduction PIM based on a reduction in involuntary residential non-pay disconnections over a four-year period in the service territory zip codes with the highest disconnection ratios. Tr. vol. 18, 224. Additionally, he recommended that the Commission implement reporting requirements. *Id.* at 230. NCJC, et al. witness Posner echoed many of the same concerns as witness Howat and ultimately recommended that the Commission reject the Low-Income/Affordability PIM and advised the Commission to adopt NCJC, et al. witness Howat's Energy Burden Reduction PIM instead. Tr. vol. 21, 1103.

In rebuttal testimony, DEP's PBR Policy Panel reiterated DEP's position that the PIM strikes the appropriate balance between encouraging outcomes sufficiently within DEP's control and providing meaningful funding to address low-income issues. Tr. vol. 23, 186.

Customer Assistance Program

In its Application, DEP requested approval of the CAP and two new tariffs, the CAP Rider and the Customer Assistance Recovery Rider (CAR Rider). DEP witness Harris testified that the CAP proposal, initially developed in the Low-Income Affordability Collaborative (LIAC) docket, is designed to assist low-income customers who are facing affordability challenges. Witness Harris described the program structure, framework, and reasoning behind the program. Tr. vol. 12, 204-05. Under the CAP, eligible customers would automatically receive a $42 monthly bill credit for a 12-month period. Tr. vol. 12, 205.

Regarding CAP eligibility, witness Harris explained that customers who are eligible for and receive funds from either the Low Income Energy Assistance Program (LIEAP) or the Crisis Intervention Program (CIP) would qualify for assistance under the CAP. DEP would automatically enroll eligible customers into CAP using a list of customers provided by the North Carolina Department of Health and Human Services (DHHS). Tr. vol. 12, 207. Moreover, DEP could re-enroll customers in CAP for another 12 bill cycles if they are re-certified as LIEAP or CIP eligible after expiration of the initial enrollment. Tr. vol. 12, 215.

Witness Harris testified that in addition to the $42 bill credit on their next 12 monthly bills, DEP will also refer CAP customers to other income-qualified weatherization and energy efficiency services that can assist customers with reducing energy usage. Tr. vol. 12, 215. DEP would spread the costs for the $42 CAP credit among all customer classes, excluding lighting schedules, through the CAR Rider. Residential customers would pay approximately 86.0% of the CAR Rider on a per kWh basis, with non-residential customers paying the approximately 14.0% remaining on a per bill basis. Tr. vol. 12, 215. The CAR Rider would have a rolling recovery factor that DEP would true-up annually to reflect the actual amount of CAP credits paid. Tr. vol.12, 207.

Public Staff witness D. Williamson recommended that the Commission: (1) approve the CAP proposal for a three-year term; and (2) require that DEP, as part of the CAR Rider proceeding, file a report addressing several issues and metrics, including the number of CAP recipients, CAP administration costs, and observed impacts of CAP on arrearage management and disconnections for nonpayment. Tr. vol. 20, 147. Witness D. Williamson noted that the Public Staff would prefer a clear legislative requirement directing the development of a program like CAP; however, he also noted that the Commission has broad authority to determine whether programs utilities design to address affordability issues are in the public interest. Tr. vol. 20, 146. Witness D. Williamson highlighted that in the Commission's Order for the 2019 Rate Case, the Commission exercised this authority by requiring that parties collaborate on developing programs that would serve the public interest and address affordability challenges for low-income customers. Tr. vol. 20, 146-47.

Sierra Club witness Colton testified that absent a program like CAP, electric bill affordability in the DEP service territory would significantly deteriorate given the increased rates proposed in the proceeding. Tr. vol. 18, 274. Witness Colton concluded that the general policy underlying DEP's CAP proposal was reasonable. Tr. vol. 18, 275. Witness Colton proceeded to make modest recommendations to the CAP proposal to advance the achievement of affordable electric bills for low-income households. Among his recommendations, witness Colton emphasized the importance of defining an affordable bill burden as a percentage of a household's income. Tr. vol. 18, 252. Witness Colton maintained that an affordable bill burden is a range and not a point, and it is appropriate, in principle, to measure affordability by reference to bills as an affordable percentage of income – regardless of the ultimate burden target the Commission deems appropriate to adopt. Tr. vol. 18, 266. Witness Colton recommended modifying the proposed across-the-board flat bill credit to a tiered, percent of bill discount. Tr. vol. 18, 276. As proposed, witness Colton's alternative program design seeks to achieve affordable bills as a percentage of household income and reduce affordability disparities between customers at different income levels, measured by the Federal Poverty Guidelines. Tr. vol. 18, 281-84.

NCJC, et al. witness Howat provided observations and analysis regarding the variances between CAP and Consensus Proposal 24 from the LIAC, the hallmarks of effective bill payment assistance programs, low-income energy usage, and burdens. Witness Howat ultimately recommended that the Commission adopt a tiered discount affordability program. Tr. vol. 18, 203-22.

CIGFUR witness Phillips testified that the costs of the proposed CAP that DEP would recover though the CAR Rider should only be recovered from residential customers, and that the creation of a new cross-subsidy benefitting residential customers at the expense of non-residential customers contradicts the express directive of the PBR Statuteto minimize interclass cross-subsidization by the greatest practicable extent possible by the end of the MYRP period. Tr. vol. 21, 482.

The Affordability Panel of DEP witnesses Barnes, Harris, and Quick responded to the affordability-related testimony and recommendations proposed by the Public Staff and

other intervenors. Witness Barnes described DEP's Affordability Ecosystem as a multi-pronged approach resulting from the LIAC's findings. Witness Barnes explained that bill payment assistance represents one lever for addressing affordability challenges, and she pointed to energy efficiency programs as another major component in DEP's Affordability Ecosystem. Tr. vol. 22, 84. Witness Barnes further disputed witness Colton's claim of LIAC's adoption of an energy burden threshold, distinguishing LIAC's target electric energy burden from CAP from witness Colton's 5.0% definition of total home energy. Tr. vol. 22, 85. Witness Barnes testified to DEP's willingness to participate in an evaluation study of North Carolina customers that would inform findings for adopting an electric energy burden threshold for Duke Energy's North Carolina customers. Witness Barnes stated that providing the zip-code level data intervenors requested would violate DEP's Code of Conduct, which prohibits disclosing aggregated non-public customer data. Tr. vol. 22, 87. DEP witness Quick testified that while DEP tracks participants in the Winter Moratorium that Commission Rule 12-11(1) established, it does not routinely collect and track customers' income status. Tr. vol. 22, 88. Due to the complexity and costs that would be added to the work of DEP's call center representatives from collecting, validating, and tracking such sensitive information, she disagreed with recommendations that DEP should collect such data and instead endorsed DEP's continued work with state or assistance agencies with the necessary experience and expertise to assist customers. Tr. vol. 22, 89.

DEP witness Harris testified that DEP agrees with the Public Staff's testimony and recommendations related to the CAP and does not oppose the proposed annual report. Tr. vol. 22, 90-91. Harris disagreed with CIGFUR witness Phillips' conclusion regarding interclass cross subsidization and stated that the program will put downward pressure on all rates. Tr. vol. 22, 91. He further testified that DEP would be amendable to a tiering feature for future versions of the CAP. Witness Harris explained that the auto-enrollment mechanism, which is a core design feature of CAP, cannot currently support tiering. Tr. vol. 22, 92-93. Further, witness Harris disagreed with recommendations that DEP, DHHS, or other organizations provide another intake service for CAP, explaining that the estimated operating costs from a third party would increase the total cost of operating CAP by a factor of almost 11. Tr. vol. 22, 93. Witness Harris testified that using a percentage discount, rather than a dollar amount, would reduce the incentive for energy efficiency investments, reduce the financial incentives for customers to respond to dynamic rate designs, and make the program's costs less predictable. Tr. vol. 22, 94.

Affordability Stipulation

On May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation. Pursuant to the terms of the Affordability Stipulation, DEP will withdraw the Low-Income/Affordability PIM and, instead, a shareholder contribution of $16 million to benefit income-eligible customers will be made as follows: $10 million in support of health and safety repairs that would allow for energy efficiency and weatherization upgrades to homes; and $6 million for the Share the Light Fund, which offers customers bill payment assistance. Tr. vol. 22, 99-100. In addition, DEP and DEC agree to collect and annually report the monthly payments ratio, which is the number of residential payments remitted divided by

the number of active residential accounts. DEP and DEC will file this data annually in Docket No. M-100, Sub 179. Furthermore, pursuant to the terms of the Affordability Stipulation, DEP would establish its CAP program as a three-year pilot. If the Commission approves CAP, DEP agrees to convene a stakeholder engagement process to consider CAP data, metrics, and future CAP program features. The Affordability Panel, the Public Staff, Sierra Club witness Colton, and NCJC, et al. witness Howat each provided testimony supporting the Affordability Stipulation. Tr. vol. 18, 326-66.

Considering all testimony and evidence along with the Affordability Stipulation, the Commission finds that the provisions of the Affordability Stipulation are reasonable and should be approved for the following reasons.

The Commission gives significant weight to the testimony of DEP witnesses Harris, Barnes, and Quick, and Public Staff witness D. Williamson regarding the Affordability Stipulation and DEP's CAP proposal. As Public Staff witness D. Williamson and DEP witness Harris highlighted in their testimony, the Commission has broad authority to set rates in the public interest. Tr. vol. 20, 146; Tr. vol. 13, 22. The question of whether the Commission should approve the CAP proposal and corresponding tariffs as outlined in the Affordability Stipulation is largely a public policy issue requiring a balancing of costs and benefits to DEP customers. The Commission established the LIAC in the 2019 Rate Case and tasked the collaborative with addressing affordability issues for low-income residential customers.

The statute authorizing performance-based regulation emphasizes reducing interclass subsidies and reducing low-income energy burdens. N.C.G.S. 62-133.16(b) requires the minimization of interclass subsidies to the greatest extent practicable by the end of the multiyear rate period. Further, N.C.G.S. § 62-133.16(d)(1) requires the Commission to consider whether the PBR application, in its entirety, "assures that no customer or class of customers is unreasonably harmed" by the proposal. N.C.G.S. § 62-133.16(d)(2) provides that the Commission may consider whether the PBR application "reduces low-income energy burdens." The Commission concludes that DEP reasonably designed the CAP proposal to meet and balance these statutory directives.

The Commission finds that the Affordability Stipulation advances the objective of reducing low-income energy burdens without causing unreasonable harm to any customer or class of customers. The Commission gives substantial weight to the DEP testimony that: (1) although the CAP causes a small interclass subsidy, residential customers primarily fund it; and (2) there is potential for the program to put downward pressure on rates for all customers, by having fewer stranded costs from disconnected accounts and arrearages, which would otherwise be passed on to the general body of ratepayers in the next general rate case.

The Commission approves the CAP as a limited-term pilot, which will allow the Commission, the Public Staff, DEP, and other parties, over time, to examine whether the CAP credit meets the public policy objectives and whether the CAP results in rates that are unreasonably discriminatory or preferential to certain customer classes. As such, the

Commission finds that it is reasonable for DEP to launch the CAP and implement the corresponding tariffs associated with the CAP proposal for a period of three years as set forth in the Affordability Stipulation.

Affordability – Next Steps

The Commission appreciates the consensus achieved by the parties in the Affordability Stipulation. Several provisions in the Affordability Stipulation provide for reporting of information. In order to examine whether the CAP meets public policy objectives, the Commission determines that it is necessary to provide guidance on these requirements.

Stakeholder Group and Report

In the Affordability Stipulation, the stipulating parties agree to convene a stakeholder engagement process to (i) consider data and reporting issues that may be necessary for the CAP, (ii) consider metrics and inputs used to assess the CAP pilot, and (iii) agree to update the Commission on the stakeholder process. The Commission directs DEP to convene this stakeholder group within 90 days of the issuance of this Order. The stakeholder group shall include the stipulating parties to the Affordability Stipulation. DEP is also directed to invite members of the LIAC to join the stakeholder group. Further, the Commission directs that the group meet at least quarterly, and that no later than 6 months after the issuance of this Order, the group must agree upon the data and information that will be provided in an annual report that will be filed each year the CAP is effective. The Commission directs that the annual report shall include, but shall not be limited to, the following information:

1. How many customers enrolled in the CAP by zip code.

2. How many dollars given in assistance by zip code.

3. Percentage of total customers enrolled in the CAP by zip code.

4. Percentage of total customers enrolled in the CAP that have had disconnections.

5. Identification of the zip codes which have the highest number of residential nonpayment disconnections.

6. Range, average, and median bill size for customers enrolled in the CAP.

7. Recommendations relating to potential changes in the CAP that would have the potential to improve the program during the pilot or as part of a subsequent program.

DEP is directed to inform the Commission if it is unable to report any of the above listed data.

The Commission notes that in Paragraph 2 of Section II the Affordability Stipulation, DEP and DEC agree to collect and report data regarding health and safety repairs that are made with shareholder funds. The Commission directs that the following information shall be provided and filed semiannually regarding these funds:

1. Dollar amount given in weatherization help to customers by zip code.

2. Dollar amount given to energy efficiency help to customers by zip code.

3. Percentage of customers that receive CAP and receive weatherization and/or EE assistance by zip code.

The report shall also identify the most frequent types of health and safety repairs that may be necessary and required to enable customers to qualify for weatherization programs.

Tiered Customer Assistance Program

The Commission further notes that the Affordability Stipulation states that parties agree to explore "a tiered customer assistance program based on income levels if that feature can be incorporated into the design of the CAP." In order to address affordability challenges in the state the Commission finds that it is necessary to direct the stakeholder group to develop a tiered program. Further, DEP is directed to file a report relating to the feasibility and proposed structure of a program the later of (i) 18 months after the entry of the order in this proceeding, or (ii) when there is one year of data from the CAP Rider. DEP shall also provide a report to the Public Staff and the Commission every six months after the entry of an order in this proceeding which summarizes the ongoing work of the stakeholder group, and which identifies any challenges as well as opportunities for improving the CAP program. DEP shall also seek from the Commission any waivers necessary or required to obtain or provide the zip code related data set forth in this Order as well as any zip code level data necessary or required to design a tiered customer assistance program.

Tracking Metrics

The Commission further finds that in order to inform future PIMs, DEP is directed to report on the following tracking metrics related to Affordability in the same manner as the tracking metrics agreed to the PIMS Stipulation:

1. The average Disconnect for Non-Payment (DNP) percentage of active residential customers over the last 12 month period.

2. The ratio of the average annual residential customer bill (1,000 kWh of usage per month) divided by the annual federal poverty income level for family of four according to the Federal Poverty Guidelines.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 42-48

Objectives of Rate Design

The evidence supporting these findings of fact is in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Reed and Byrd, Public Staff witnesses Williamson and Nader, Commercial Group witness Chriss, Kroger Co. and Harris Teeter witness Bieber, DoD-FEA witness Blank, CIGFUR witnesses Phillips and Gorman, AGO witness Nelson, and CUCA witnesses O'Donnell and Heilig; the Partial Revenue Requirement Stipulation; and the entire record in this proceeding.

DEP witness Reed testified that she used the cost-of-service information prepared by DEP and examined by DEP witness Hager to design rates. Tr. vol. 11, 176. Witness Reed testified that she also reviewed and considered the rates of return across the customer classes derived from the COSS when designing rates. *Id.* Finally, witness Reed noted that she reviewed DEP's Advanced Metering Infrastructure (AMI) data to examine customers' usage characteristics and to determine relationships between energy and demand, both on a coincident peak and non-coincident peak basis that might prove pertinent to the design of DEP's rates, including the development of new TOU periods. *Id.* at 176-77.

Witness Reed stated that one objective of DEP's proposed rate design is to achieve the necessary increase in rates to collect the total revenue requirement. *Id.* at 177. Witness Reed also stated that another DEP objective is to gradually align the cost to serve customers within its residential, general service, and lighting rate schedules. *Id.* Witness Reed also noted that DEP's goal is to design rates that reflect the costs that a customer causes DEP to incur. *Id.* With respect to the rate increases proposed in this case, witness Reed stated that the base rate increase has been allocated to the rate classes by base rate amounts. *Id.* at 180. Witness Reed claimed that this allocation methodology aims to distribute the increase equitably to the classes while maintaining each class's deficiency or surplus contribution to return. *Id.*

In his direct testimony, DEP witness Byrd testified that DEP, as ordered by the Commission, participated in a year-long Comprehensive Rate Design Study (CRDS) with external stakeholders to develop DEP's future pricing and rate design options. *Id.* at 231. Following this engagement, DEP proposed several rate design changes to incorporate stakeholder requests and input. *Id.* at 232.

DEP witness Reed testified in detail regarding changes that DEP proposes to the residential rate schedules, the SGS rate schedules, the MGS rate schedules, the LGS rate schedules, the seasonal and intermittent rate schedules, and to the lighting rate schedules. Tr. vol. 11, 183-202. DEP witness Reed also testifies in detail regarding the

proposed revisions to DEP's service riders, which are offered to reflect special customer needs and requirements. Her testimony describes how the riders have been revised to better reflect cost of service. *Id.* at 202-06.

Having considered the record evidence on the issue of rate design, the Commission concludes that the objectives of DEP's rate design – which are to: (1) achieve the necessary increase in rates to collect the total revenue requirement; (2) further align the cost to serve customers within DEP's residential, general service, and lighting rate schedules; and (3) design rates that reflect the costs a customer causes DEP to incur – are reasonable. Further, the Commission concludes that DEP's proposed allocation of the approved revenue increase to the customer classes is reasonable to all parties, considering the evidence presented and is approved for the purposes of this proceeding. Finally, for the foregoing reasons, the revisions to the rate schedules and to the service riders proposed by DEP in this proceeding are reasonable and are approved as proposed, unless otherwise specifically addressed hereinafter in this Order.

Subsidy Reduction

DEP evaluated rates of return across customer classes emanating from DEP's COSS. Tr. vol. 11, 179. DEP witness Reed testified that the historical per books rate of return indices as measured by the ratio of class rate of return to retail rate of return, shows that over a lengthy period, residential customers have been subsidized. She testified that his historical subsidy has, in the past, been beyond the range of reasonableness, which DEP defines as class rates of return within 10.0% of the total Company rate of return. *Id.* She also testified that an updated comparison through the test period now shows significant convergence of the class rate of return over all classes towards the band of reasonableness demonstrating the success of the strategy of gradually reducing the subsidy/excess by 10.0%. *Id.* at 180-81.

DEP witness Reed explained that in designing rates, the base rate increase was allocated to the rate classes by rate base amounts and that this allocation method distributes the increase equitably to the classes while maintaining each class's deficiency or surplus contribution to return. *Id.* at 18.

DEP witness Reed testified that, in this proceeding, DEP is also recommending a variance reduction of 10.0% to help reduce interclass subsidies to better align each rate class to the average rate of return. *Id.*

CIGFUR witness Phillips testified that he disagreed with DEP's proposed 10.0% subsidy reduction and instead recommended that a 25.0% subsidy reduction, consistent with DEP's last rate case proceeding, be the minimum reduction for this proceeding. Tr. vol. 21, 483. Witness Phillips testified that a subsidy reduction of 50.0% or even 100.0% would be preferable. *Id.* Witness Phillips claimed that LGS customers are subsidizing other rate classes by approximately $47.7 million under current rates, that the proposed 10.0% subsidy reduction does not adequately correct this cross-subsidization, and that LGS customers should receive a rate reduction to eliminate the subsidy. *Id.*

Witness Phillips also stated that DEP's proposed 5.8% LGS rate increase will "continu[e] the large subsidy paid by these customers". *Id.*

DoD-FEA witness Blank also took issue with DEP's proposed 10.0% subsidy reduction and stated that DEP's proposed allocation of base rate revenue increases deviates substantially from its COSS results. *Id.* at 310. Witness Blank claimed that DEP's proposed rate increases result in the LGS class subsidizing other classes, particularly the residential class. *Id.* at 326. Witness Blank argued that the use of any variance, even a higher variance than DEP's proposed 10.0%, will not alleviate the subsidization faced by the LGS class, will still lead to rate increases for LGS and LGS-TOU rate classes, and will lead to rate increases "well above a level that I would be comfortable with," for rate classes farther away from cost-based rates. *Id.* Therefore, witness Blank recommended that the Commission reject the use of a variance reduction approach, even at a higher level (e.g., 25.0%) than the 10.0% DEP proposed. *Id.*

On rebuttal, witness Reed testified that the proposed 10.0% subsidy reduction "balances the rate increases requested … so that no rate class receives a disproportionate increase [due to] the proposed changes to the cost-of-service methodology [shifting] costs among rate classes." Tr. vol. 11, 264. Specifically, witness Reed explained that if DEP had employed witness Phillips' recommended 25.0% subsidy reduction the proposed increase to the residential class would increase from 9.9% to 10.4% and the proposed increase to the Lighting class would increase from 19.9% to 24.9%. *Id.* at 265. Witness Reed stated that DEP's 10.0% subsidy reduction proposal applies the concept of gradualism to align revenues collected from each class with cost causation from DEP's class cost of service study (CCOSS) but that DEP does not intend it to signal that DEP will limit future subsidy reductions to 10.0%. *Id.*

During the expert witness hearing, in response to cross-examination by CIGFUR, CUCA, and DoD-FEA, witness Reed acknowledged that other customer classes have historically subsidized residential customers. *Id.* at 324, 360, 386-87. However, witness Reed explained that DEP intends for the 10.0% subsidy reduction to move the rate increase for each rate class toward parity with the rate of return while avoiding harm to certain classes. *Id.* at 387-88. Moreover, witness Reed reiterated that in determining the 10.0% subsidy reduction, DEP attempted to balance the change in cost-of-service with the requested rate increases so that certain rate classes would not be overly burdened with a rate increase. *Id.* at 326. Witness Reed further explained that employing a 25.0% subsidy reduction "would really harm certain [customer] classes." *Id.* at 388.

During the expert witness hearing, witness Reed also asserted that DEP's proposed 10.0% variance reduction was consistent with N.C.G.S. § 62-133.16. *Id.* at 318-21, 330. During cross-examination by CIGFUR, witness Reed acknowledged that N.C.G.S. § 62-133.16 requires DEP to minimize interclass subsidization. However, witness Reed emphasized that the statute only requires DEP to minimize interclass subsidization "to the greatest extent practicable," which is what it has done. *Id.* As witness Reed explained in response to cross-examination by the NCLM, this is particularly true given that the PBR Statute also requires the Commission to consider the possibility for

rate shock. Tr. vol. 12, 14. As such, witness Reed testified that DEP appropriately considered "competing priorities" such as cost causation, rate shock, and gradualism in proposing the 10.0% variance reduction. Tr. vol. 11, 320-21.

Based on the evidence in the record, the Commission agrees that a variance reduction of 10.0% is reasonable for application in this proceeding. In reaching this conclusion, the Commission gives significant weight to the testimony of witness Reed that a 10.0% subsidy reduction helps move towards eventual rate parity and minimize interclass subsidization, including but not limited to the historic subsidization of the residential class, while considering and incorporating other important factors. Additionally, the Commission recognizes that witness Phillips' argument in support of a greater variance reduction raises a legitimate concern, but concludes that, a variance reduction is not the only issue that a utility must consider when designing rates. The Commission also declines to accept witness Blank's recommendation to completely disallow a variance reduction. The Commission has historically approved a variance reduction for DEP and witness Blank has offered no compelling evidence warranting a departure from this prior practice. Accordingly, the Commission finds that a 10.0% subsidy reduction is just and reasonable and consistent with the PBR Statute, moves rates closer to cost for all customer classes and is less likely to lead to rate shock than a larger subsidy reduction.

Migration Adjustment

DEP witness Reed testified that during the rate design process, DEP analyzed rate migration, which occurs when customers change from their current tariff to a tariff that is more cost-effective for them. Tr. vol. 11, 181. Witness Reed claimed that, due to the introduction of new tariffs, the redesign of other tariffs to better align with system costs, and the ability of DEP's new Customer Connect billing system to perform rate comparisons and suggest the best rate for customers, DEP recommends a migration adjustment to the residential, MGS, and LGS classes. *Id.* at 181, 265-66. Specifically, DEP requests a migration adjustment to residential and MGS classes for customers who would save 10.0% or more annually and to the LGS class for customers who would save 5.0% or more annually. *Id.* at 181, 266. Witness Reed noted that this proposal would result in a $12 million migration adjustment for the residential class in Rate Year 0, an approximately $8 million migration adjustment for the MGS class each rate year, and an approximately $1.2 million migration adjustment for the LGS class each rate year. *Id.* at 181-82. Witness Reed noted that DEP is only requesting a migration adjustment for the residential class in Rate Year 0 and not Rate Years 1, 2, or 3 because under the MYRP a migration adjustment is unnecessary due to the Residential Decoupling Mechanism. *Id.* at 181-82, 370. In contrast, witness Reed testified that the proposed migration adjustment for the MGS and LGS classes will carry forward in each rate year including Rate Year 0 and Rate Years 1, 2 and 3 under the MYRP. *Id.* at 182. Witness Reed explained that the primary driver for the migration adjustment requests for the MGS and the LGS classes is the realignment of TOU windows to system costs which allows customers to respond to more economically efficient price signals. *Id.* Witness Reed's Direct Exhibits 4, 4_1, 4_2, and 4_3 provided the requested migration amounts. *Id.* Tr. Ex. vol. 11.

DoD-FEA was the only party to challenge DEP's requested migration adjustment. DoD-FEA witness Blank requested that the Commission deny DEP's proposed migration adjustment because it artificially increases DEP's base revenue recovery to account for an amount of lost future revenue that is not known or measurable. Tr. vol. 21, 314. Witness Blank argued that the migration adjustment presumes customers will switch rate schedules when they understand potential utility bill savings even though customers choose rate schedules for reasons beyond those a simple bill analysis suggests. *Id.* Witness Blank argued that the relative risk between rate designs and anticipated events that may affect future demand and usage influences actual customer choice. *Id.* Witness Blank argued that DEP's migration adjustments assume that customers will switch rate schedules and does not account for customer risk aversion, which may impact their willingness to switch even when potential utility bill savings are possible. *Id.* Witness Blank acknowledged that some migration will likely occur but argued that it is reasonable for DEP to bear such risk since it is a short-term risk that it can remedy during its next rate case when it better knows customer behavior. *Id.* at 314-15. Witness Blank also noted that future changes to customer electricity usage and billing are "an overall unknown," including potential increases that expanding EV ownership or a rise in the number of homes using electric heating could drive. *Id.*

In rebuttal testimony, DEP's Rate Design Panel, witnesses Byrd and Reed, disagreed with witness Blank's contention that the migration adjustment accounts for lost revenue that is unknown and unmeasurable. Tr. vol. 11, 266-68. The Rate Design Panel testified that in determining the migration adjustment, actual customer billing data was used to calculate actual savings on customer bills. *Id.* at 267. Specifically, the Rate Design Panel explained that for each participant in the rate class, individual customer bills were calculated on their current rate schedule at proposed rates and at other available rate schedules in their rate class at proposed rates. *Id.* at 266. The net annual savings from individual customers saving more than the threshold were then aggregated to determine the migration adjustment amount. *Id.* The Rate Design Panel further stated that DEP considers its proposed 10.0% and 5.0% savings thresholds to be conservative estimates of anticipated migration levels. *Id.* During cross-examination by the DoD-FEA, witness Reed explained that the proposed migration adjustment is a "conservative estimate" because it only considered "structural savers" – i.e., customers that would automatically save money simply by transitioning to a different rate schedule – and does not include customers below the savings threshold that may want to switch or customers that may save money through behavioral changes. *Id.* at 372, 376.

The Rate Design Panel also testified that the availability of several tools that will help customers switch to the best rate mitigates witness Blank's concerns regarding the migration adjustment. *Id.* at 267-68, 373. First, customers who have 12 months of usage history will have access to DEP's Rate Comparison Tool – an online tool (part of Customer Connect) that leverages historic interval data to determine a customer's best rate. *Id.* at 267. Second, customers may also contact DEP's Call Center Representatives to request a rate comparison. *Id.* Third, LGS class customers can also utilize their Large Account Managers. Tr. vol. 11, 267, 373. As witness Reed explained during cross-examination by

the DoD-FEA, these Large Account Managers help LGS customers both manage their complex rates and determine the best rate. *Id.* at 373.

The Commission concludes that DEP's proposed migration adjustment is just and reasonable considering the evidence of record in this proceeding. The Commission is not persuaded by DoD-FEA witness Blank that the lost revenues for which the migration adjustment is intended to compensate are unknown and unmeasurable. DEP witness Reed offered convincing testimony that the Rate Design Panel calculated the migration adjustment based on actual customer billing data and that the 10.0% and 5.0% savings thresholds are reasonable, conservative estimates of DEP's migration exposure. The Commission also considers witness Reed's testimony, describing how the Rate Comparison Tool, Call Center Representatives, and Large Account Managers will mitigate migration concerns and help customers switch to rates that may allow them to lower their bills, to be an adequate response to witness Blank's concerns. The Commission therefore accepts DEP's proposed migration adjustments and finds they should be approved as DEP proposed them for the purposes of this proceeding.

Customer Growth and Weather Normalization

DEP witness Reed testified that she provided the retail sales and number of customers to DEP witness Jiggetts for use in calculating the pro forma adjustment for growth in customers. Tr. vol. 11, 173. Witness Reed explained that to arrive at the appropriate number of customers served and the attendant annualized sales levels at the end of the test period, DEP used a combination of regression analysis and a customer-by-customer approach. *Id.* at 173-74.

In her supplemental direct testimony, witness Reed testified that DEP had agreed with the Public Staff to periodically update the Customer Growth Analysis to extend the results to the end of the pro forma period. *Id.* at 223. As such, witness Reed testified that DEP had updated the Customer Growth Analysis through December 31, 2022, for informational purposes only, as DEP witness Jiggetts' Supplemental Direct Testimony Exhibit 4 Pro forma NC1040 demonstrates. Tr. Ex. vol. 13.

CIGFUR witness Gorman testified that DEP's sales projection for residential and SGS customers in the base period is unreasonably low. Tr. vol. 21, 405, 425-26. Witness Gorman claimed that DEP bases its pro forma adjustments on weather normalized use per customer in a single year, which does not reflect how customers' usage can vary due to customer behavior, introduces uncertainty, and does not provide a reasonable projection of likely future customer electricity usage. *Id.* at 426. Witness Gorman recommended that DEP instead use a four-year average projected use per residential customers normalized sales projection. *Id.* at 428.

On rebuttal, the Rate Design Panel disagreed with witness Gorman's claim that DEP's residential weather normalized sales were too low. Tr. vol. 11, 268. The Rate Design Panel testified that DEP bases energy usage projections for the residential and SGS customer classes on historical actual weather normalized sales, which means that

DEP uses kWh sales over the test year and extended period and applies monthly factors based on 30 years of historical weather data to normalize sales for weather. *Id.* The Rate Design Panel also testified that witness Gorman was incorrect in his claim that DEP's pro forma adjustments are based on weather normalized use per customer in a single year. *Id.* The Rate Design Panel explained that the true-up of DEP's test year and extended period estimate of number of customers is based on the best fit of seven different regression models and that the analyses use four, three, two, and one-year time periods for projections. *Id.* at 268-69. The regression analysis that is best aligned with the data (highest statistical "R" value) is then selected. *Id.* at 269. Finally, the Rate Design Panel disagreed with witness Gorman's recommendation that DEP use a four-year average projected use per Residential customer normalized sales projection; the method currently used has been thoroughly vetted by the Public Staff and has been approved by the Commission in prior rate cases. *Id.* Moreover, the Rate Design Panel explained that if the Commission approves DEP's request for an MYRP, residential revenues will be decoupled. *Id.*

The Commission concludes that DEP's proposed weather normalization and customer growth adjustment are reasonable in light of the evidence presented. The Commission, therefore, rejects witness Gorman's recommendation because his proposal does not appear to provide a meaningful improvement over DEP's current methodology. Moreover, the Commission concludes that the evidence in this case does not support a departure from a customer normalized sales projection methodology that the Public Staff has scrutinized and the Commission has approved previously.

Updated Time of Use Periods

DEP witness Byrd, in his direct testimony, testified that DEP is proposing updated and aligned TOU periods across its tariffs that contain time-differentiated pricing for residential and non-residential customers. Tr. vol. 11, 233. Specifically, DEP is proposing to refresh TOU periods as follows (peak periods do not include weekends or holidays):

- On-Peak (Summer) – 6:00 p.m. – 9:00 p.m.
- On-Peak (Non-Summer) – 6:00 a.m. – 9:00 a.m.
- Discount (Summer) – 1:00 a.m. – 6:00 a.m.
- Discount (Non-Summer) – 1:00 a.m. – 3:00 a.m. and 11:00 a.m. – 4:00 p.m.
- Summer consists of the months May – September
- Non-Summer consists of the months October – April.

Id. at 234. Witness Byrd testified that the impacted rate schedules include Residential Service Time-of-Use Schedule R-TOU, Residential Service Time-of-Use Demand Schedule R-TOUD, SGS-TOUE, SGS Time-of-Use Schedule SGS-TOU

(renamed Schedule MGS-TOU), LGS-TOU, LGS-RTP, and the Large Load Curtailable Rider LLC. *Id.* at 241. Schedules R-TOU-CPP and SGS-TOU-CPP already use these proposed periods and will not be impacted. *Id.*

Witness Byrd explained that DEP's existing TOU periods, established decades ago, are no longer appropriate and increasingly do not align with DEP's current and anticipated system needs. *Id.* at 235. Witness Byrd stated that the new TOU periods will benefit customers and advance several policy goals. *Id.* at 241. Specifically, witness Byrd testified that the new TOU periods will properly align price signals to cost differences that exist across different seasons and hours, thereby encouraging peak load reduction and efficient system usage; provide the opportunity for economic use of new technologies, such as smart energy management devices, energy storage, and EVs; and encourage flexible consumption during times of low system costs, providing incentives for distributed energy resource adoption. *Id.* at 234, 241-42. Witness Byrd testified that the TOU periods proposed were taken directly from observations of the Cost Duration Model (CDM) and were discussed and evaluated at length with stakeholders during the CRDS. *Id.* at 235-36. Moreover, witness Byrd notes that the proposed TOU periods have already been approved by the Commission for two of DEP's current tariffs: R-TOU-CPP and SGS-TOU-CPP. *Id.* at 235.

The AGO was the only party that recommended any revisions to DEP's proposed TOU periods. AGO witness Nelson recommended that DEP shift its proposed Summer On-Peak period one hour earlier to 5:00 to 8:00 p.m. Tr. vol. 18, 89. Witness Nelson claimed that this Summer On-Peak period would better reflect system costs during each year of the CDM output (2021, 2026, and 2030). *Id.* at 86. Witness Nelson was particularly concerned with DEP's use of the 2030 CDM output and argued that DEP should not weight it as heavily as 2021 and 2026 output when designing current rates since it is farthest in the future and therefore the most uncertain. *Id.* at 89.

In his rebuttal testimony, DEP witness Byrd disagreed with the AGO's position that DEP should shift the Summer On-Peak period to 5:00 to 8:00 p.m. Tr. vol. 11, 269. Witness Byrd reiterated that DEP discussed and evaluated the proposed 6:00 to 9:00 p.m. Summer On-Peak period at length with stakeholders during the CRDS; DEP based the proposal on observations from the CDM; and the peak period balances several factors, including system costs through 2030 and customer experience. *Id.* at 270. In response to the AGO's concerns regarding DEP's forward-looking approach in designing the new TOU periods, witness Byrd explained that it is important that DEP revise its TOU periods now, before many residential customers are on TOU rates, to minimize disruption once more customers are on TOU rates and have established behavioral patterns. *Id.* at 304. Additionally, witness Byrd explained that TOU periods that consider expected system evolution are appropriate because they will be durable and can last for several years. *Id.* Moreover, witness Byrd testified that if the Commission adopted witness Nelson's recommendation to shift the Summer On-Peak period to 5:00 to 8:00 p.m., customers on Rate Schedules R-TOU-CPP and SGS-TOU-CPP – under which the Summer On-Peak period is 6:00 to 9:00 p.m. – would experience a change in TOU periods after having only been on these rate schedules for a short period. *Id.* at 270. As such, given the recent approval of Rate Schedules R-TOU-CPP and SGS-TOU-CPP, shifting the Summer On-

Peak period to 5:00 to 8:00 p.m. would presumably alter these customers' expectations of TOU period stability. *Id.* Finally, witness Byrd testified that the proposed 6:00 to 9:00 p.m. Summer On-Peak period better aligns with the anticipated increased levels of solar generation on the system, as contemplated in the Commission's Carbon Plan, which will shift the net peak to later in the afternoon. *Id.* at 270-71.

The Commission declines to adopt witness Nelson's recommended change to shift the Summer On-Peak period to 5:00 to 8:00 p.m. DEP witness Byrd offered convincing testimony that it would not be reasonable to shift the Summer On-Peak period to 5:00 to 8:00 p.m. given that the CRDS analyzed the 6:00 to 9:00 p.m. Summer On-Peak period,, DEP based the proposal on the CDM, and the Commission has already approved the Summer On-Peak period for DEP's Rate Schedules R-TOU-CPP and SGS-TOU-CPP. In addition to ensuring proper price signaling and encouraging customer adoption of new technologies, the evidence strongly indicates that DEP's modernized TOU periods will improve price and cost causation alignment. Accordingly, the Commission concludes that DEP's new TOU periods should be approved as proposed.

Residential

The residential rate class includes the following rate schedules: Residential Service Schedule RES, Residential Service Time-of-Use Demand Schedule R-TOUD, Residential Service Time-of-Use Schedule R-TOU, and Residential Service Time-of-Use with Critical Peak Pricing Schedule R-TOU-CPP. Tr. vol. 11, 184.

DEP witness Reed testified that DEP proposes to re-open and modify Residential Rate Schedule R-TOUD to modernize the TOU periods and to update the demand charge structure to better reflect cost causation. *Id.* Witness Reed explained that the CRDS addressed R-TOUD tariff redesign and that the modified tariff will provide customers with more choices regarding their energy consumption. *Id.* at 185. Additionally, witness Reed testified that in response to feedback from customers, DEP also proposes to expand the applicability of residential rates to include detached garages, barns, or other structures that are at the same service address as a separate, primary residential account. *Id.* at 187. Witness Reed testified that if the Commission approves the expansion, DEP will allow existing customers to move from a general service schedule to a residential schedule for detached structures at the same premises as the residential account. *Id.* at 188. Further, witness Reed testified that while DEP's unit cost study justifies an increase to the monthly Basic Customer Charge to better reflect customer-related costs and minimize customer cross-subsidization, DEP is not proposing to raise the Basic Customer Charge in this proceeding. *Id.* at 186. Specifically, witness Reed testified that DEP is proposing to maintain the monthly residential Basic Customer Charge for the R-TOUD, R-TOU, and R-TOU-CPP rate schedules at $16.85. *Id.* Reed Direct Exhibits 6, 6_1, 6_2, and 6_3 illustrate the Basic Customer Charges for the major customer classes for the proposed rate years. *Id.* at 170. Tr. Ex. vol. 11.

In his direct testimony, AGO witness Nelson recommended that the Commission explore making TOU rates default for the residential class. Tr. vol. 18, 111-12. Witness

Nelson argued that DEP's default residential rate schedule – Schedule RES – includes a non-time-varying energy rate that does not send accurate price signals to residential customers, thereby causing more costs to be incurred by customers and DEP during peak hours. *Id.* at 110-11. As such, witness Nelson argued that providing DEP with an incentive to get residential customers on a TOU rate is inappropriate and costly. *Id.* at 111. Instead, the Commission should explore other avenues for expanding residential TOU rates, such as making TOU rates default for the residential class. *Id.* at 111-12.

In his direct testimony, Public Staff witness Williamson testified that while he generally supports the proposed changes to the rate schedules, he proposed a few minor modifications. Tr. vol. 20, 172. Specifically, witness Williamson recommended that the Commission approve DEP's proposal to allow detached garages, barns, and other structures on the same residential premise to be served under a residential rate schedule. *Id.* at 173-75. However, witness Williamson recommended that DEP notify all SGS customers of this change through bill insert or separate mailing. *Id.* at 175, 180. Additionally, regarding DEP's Basic Customer Charge, witness Williamson recommended that DEP set the Basic Customer Charge for Schedules R-TOU and R-TOUD at the same $14.00 per month rate as Schedule RES. *Id.* at 173, 180.

DoD-FEA witness Blank also testified regarding DEP's proposed rate increase for the residential class. Tr. vol. 21, 322-23. Specifically, witness Blank recommended that DEP's proposed rate increase for the residential class not exceed 1.25 times the overall retail base revenue increase. *Id.*

In their rebuttal testimony, the Rate Design Panel disagreed with witness Nelson's recommendation to make TOU rates default for the residential class. Tr. vol. 11, 281. Witnesses Reed and Byrd testified that the choice to switch to a TOU rate should be with the customer because TOU rates only yield system benefits if customers respond to price signals and shift load away from peak periods. *Id.* During the expert witness hearing, witness Reed explained that forcing a residential customer to switch to a TOU rate could be harmful and result in higher bills if they cannot manage their energy usage in response to price signals. *Id.* at 312. Therefore, witness Reed testified that DEP's preferred approach to expanding TOU rate adoption is to make TOU rates more appealing and encourage voluntary adoption. *Id.* at 281, 311.

In response to the Public Staff's recommendations relating to the residential class, the Rate Design Panel accepted the Public Staff's proposal to notify all SGS customers through bill insert or a separate mailing about the expanded applicability of residential rates to include detached garages, barns, and other structures that are at the same service address as a separate, primary residential account. *Id.* at 283. DEP also accepted the Public Staff's proposal to set the Basic Customer Charge for Rate Schedules R-TOU and R-TOUD at $14.00. *Id.* at 280.

The Rate Design Panel also disagreed with witness Blank's recommendation to cap the rate increase for the Residential class. *Id.* at 282. The Rate Design Panel explained that witness Blank's rate increase proposal would shift the rate increase for the LGS class to other

customer classes which is not in line with the need to balance cost causation alignment, gradualism, and the avoidance of rate shock. *Id.* During the expert witness hearing, witness Reed explained that by shifting the rate increase from the LGS class to other customer classes, including the residential class, witness Blank's rate increase proposals benefit the LGS class at the expense of all other customer classes, including rate increases of over 100 percent for some classes. *Id.* at 385-86, 390.

In light of the parties' testimony and all the evidence presented, the Commission concludes that DEP's proposed rate design for the residential rate class, including the Public Staff modifications to which DEP agreed, is just and reasonable. The Commission agrees with witnesses Reed and Byrd that the decision to switch to a TOU rate should be with the customer. Additionally, the Commission accepts the Public Staff's testimony regarding the appropriateness of modifying the Basic Customer Charge for Schedules R-TOU and R-TOUD to be set at the same $14.00 rate as Schedule RES. This is the same Basic Customer Charge the Commission approved in DEP's last rate case, when it found that it appropriately balances the needs to offer rates that more clearly reflect actual cost causation, minimize subsidization, and provide proper price signals to customers in the rate class, while also moderating the impact of rate increases on low-usage customers. *See* 2019 DEP Rate Order 203. Accordingly, the Commission concludes that the Basic Customer Charges as set forth in Reed Exhibits 6, 6_1, 6_2, and 6_3 are just and reasonable and are therefore approved.

Medium General Service (MGS) and Large General Service (LGS)

The MGS rate class includes all nonresidential customers with demand requirements from 30 kW to 1,000 kW and consists of the following rate schedules: MGS, SGS-TOU (proposed to be renamed MGS-TOU), SGS (Thermal Energy Storage) Schedule GS-TES, Agricultural Post-Harvest Processing (Experimental Thermal Energy Storage) Schedule APH-TES, Church Time-of-Use Schedule CH-TOUE, Church and School Service Schedule CSE, and Church and School Service Schedule CSG. Tr. vol. 11, 190. The LGS class includes all nonresidential customers with demand requirements of 1,000 kW or greater and consists of the following rate schedules: LGS, LGS-TOU, and LGS (Real Time Pricing) Schedule LGS-RTP. *Id.* at 194.

In her direct testimony, DEP witness Reed described the proposed rate design for the MGS and LGS rate schedules[9]. *Id.* at 190-93. Witness Reed testified that DEP is proposing to increase the Basic Customer Charge for the MGS and LGS classes to better reflect the cost of serving these customers. *Id.* at 190. Specifically, witness Reed stated that DEP proposes to increase the Basic Customer Charge for the MGS class for all rate years from $28.50 to $30.00 per month for single-phase service, or $39.00 if the customer requests three-phase service and/or is on Schedule SGS-TOU (MGS-TOU). *Id.* at 190-91. Additionally, DEP proposes to increase the Basic Customer Charge for the LGS class for all rate years from $200.00 to $210.00 per month. *Id.* at 194.

[9] Note that DEP's proposed changes to Schedule LGS-RTP are discussed *supra*.

DEP witness Byrd testified explaining DEP's proposal to change the demand charge structure for renamed Schedule MGS-TOU and Schedule LGS-TOU. *Id.* at 243-45. Specifically, witness Byrd stated that DEP proposes a three-part demand structure consisting of the following components: a Base Demand Charge, designed to recover distribution costs, which DEP would apply to the higher of either (1) a customer's highest maximum demand across all periods over the previous 12 months, or (2) 50.0% of the Contract Demand; a Mid-Peak Demand Charge, designed to recover off-peak and discount allocation of production and transmission costs, which DEP would apply to a customer's maximum demand during off-peak or on-peak periods but excluding discount periods; and a Peak Demand Charge, designed to recover peak allocation of production and transmission costs resulting from the customer's contribution to system demand during peak hours, which DEP would apply to a customer's measured on-peak demand. *Id.* at 243-44. Witness Byrd explained that the proposed three-part demand structure will improve price transparency and better align with cost causation based on both the size and timing of customer demands and is meant to work in tandem with DEP's proposed TOU periods. *Id.* at 244.

Additionally, witness Byrd testified that, in response to stakeholder feedback during the CRDS, DEP evaluated the alignment of bills and pricing to cost causation. *Id.* at 245. Witness Byrd stated that this analysis showed that shifting a portion of fixed cost recovery from energy charges to demand charges improved alignment to cost causation across a wide spectrum of customer energy usage profiles with very little impact on customer bills. *Id.* Witness Byrd stated that as a result of this evaluation DEP witness Reed proposed that DEP institute pricing that reflects slightly higher recovery through demand charges for TOU rates. *Id.*

Kroger Co. and Harris Teeter witness Bieber testified regarding DEP's proposed MGS-TOU rate design. Tr. vol. 21, 694-702. In his direct testimony, witness Bieber acknowledged that DEP's proposed MGS-TOU rates "improve alignment between the charges and the underlying embedded costs," but noted that they are "...still substantially lower than the demand unit cost." *Id.* at 694. Witness Bieber recommended "moderate" and "revenue-neutral" changes to DEP's proposed MGS-TOU energy and demand charges that he contends will improve the alignment between the rate component and the underlying costs while employing the principle of gradualism and mitigating intra-class rate impacts. *Id.* at 697-98. Specifically, witness Bieber recommended that DEP's proposed three-part demand charges each be increased by an additional 20.0% and that the proposed off-peak energy charge be reduced by a corresponding amount. *Id.* at 698. If the Commission determines that an even more gradual approach to align rates with DEP's underlying costs is appropriate, witness Bieber provided an alternative recommendation: that MGS-TOU Base Demand Charge, Mid-Peak Demand Charge, and Peak Demand Charge each be increased by proportionally so that the sum of the three charges is no less than 60.0% of the unit cost of demand from DEP's proposed COSS for the corresponding rate year, with a corresponding adjustment to the off-peak energy charge so that the modification is revenue neutral. *Id.* at 700.

Commercial Group witness Chriss also expressed concern that DEP's proposed MGS-TOU rate design does not reflect the underlying cost to serve and as a result shifts cost

responsibility within the rate classes. *Id.* at 527-28. Witness Chriss claimed that DEP has not fully aligned the proposed MGS-TOU demand charges with the underlying demand-related costs. *Id.* at 527. Witness Chriss testified that collecting demand-related costs through an energy charge is inconsistent with cost causation principles and results in a shift in demand cost responsibility from lower load factor customers to higher load factor customers, which will overpay for demand-related costs DEP incurs through providing service to them. *Id.* at 528. Witness Chriss also claimed that DEP would benefit by recovering more demand-related costs through a demand charge instead of through the energy charge since it would be less susceptible to weather-related and other fluctuations in usage, resulting in greater revenue certainty and more stable utility earnings. *Id.* at 528-29. Witness Chriss testified that, for the purposes of this case, the Commercial Group does not oppose DEP's proposed rate levels for MGS-TOU at DEP's proposed revenue requirement, if there is a decrease from the proposed revenue requirement, the Commercial Group recommended that DEP apply such decrease proportionately to the energy charges to better align costs to the cost of service. *Id.* at 529.

In his direct testimony, AGO witness Nelson also took issue with DEP's proposal to increase the level of fixed costs it recovers through demand charges. Tr. vol. 18, 20, 93-101. Witness Nelson testified that DEP has not sufficiently demonstrated that its approach to increasing cost recovery through demand charges will improve alignment with cost causation or that it will result in superior price signals. *Id.* at 94-97. Specifically, witness Nelson claimed that the way DEP categorizes electric system costs as fixed and not fixed does not account for many power system characteristics and "reflects an oversimplification of cost classification…over-emphasizes short-term costs [and] revenue collection and de-emphasizes long-term asset avoidance and system efficiency". *Id.* at 95. Accordingly, witness Nelson recommended that DEP increase energy charges for Schedules MGS-TOU and LGS-TOU to a level that is above marginal cost while maintaining strong price ratios between On-Peak, Off-Peak, and Discount periods to send price signals to customers, and correspondingly decrease demand rates to reflect the revised energy rates. *Id.* at 93, 97, 99. Witness Nelson also recommended that DEP propose Critical Peak Pricing (CPP) rate options for MGS and LGS customers since they can contribute to lower costs and improved system reliability. *Id.* at 93, 101-06. Witness Nelson claimed that while well-designed TOU rates can improve alignment with system costs, they are not precise enough to sufficiently incentivize load shifting during critical peak events. *Id.* at 102-05. Witness Nelson testified that CPP tariffs provide utilities with the ability to flexibly identify peak load events and incentivize customers to shift load during short, but highly impactful, periods of system load. *Id.* at 102.

CUCA witness O'Donnell testified regarding DEP's proposed LGS-TOU rate design. Tr. vol. 21, 655-60. Overall, witness O'Donnell claimed that the LGS-TOU rate design is "overly complex", not beneficial to the LGS class, and would benefit DEP, not energy consumers. *Id.* at 657-59. Witness O'Donnell also testified that he did not agree with DEP's proposals to implement a Mid-Peak Demand Charge, which is "not consistent with the realities of how much manufacturing happens in North Carolina," noting that when manufacturers are "on they are on for as long as it takes," meaning they are not typically able to shutdown mid-production to avoid peak times. *Id.* at 655-56. Witness O'Donnell stated that he objected to the inclusion of a ratchet in the Base Demand Charge, which

he argued could lock customers into an overly expensive and unrepresentative demand charge if their peak demand occurs during an on-peak period. *Id.* at 658-59. As such, witness O'Donnell recommended removal of the Mid-Peak Demand Charge and the ratchet from the Base Demand Charge. *Id.* at 655-56, 659.

In their rebuttal testimony, the Rate Design Panel disagreed with the intervenors' various adjustments to DEP's proposed MGS and LGS rate design. Tr. vol. 11, 271-79. Specifically, DEP disagreed with witness Bieber's recommendation to increase the MGS-TOU three-part demand charges by an additional 20.0% and to reduce the proposed off-peak energy charge by a corresponding amount. *Id.* at 271-72. The Rate Design Panel explained that while witness Bieber's proposal is directionally aligned with DEP's approach, it does not sufficiently consider gradualism and would lead to materially adverse outcomes, such as rate shock, for lower load factor customers. *Id.* at 272. In contrast, the Rate Design Panel testified that DEP's approach to slightly increasing demand charges and correspondingly decreasing energy charges better balances gradualism with alignment to cost-of-service. *Id.*

Additionally, while DEP disagreed with witness Chriss' recommendation that DEP allocate any decreased revenue requirement proportionately to the energy charges on Schedule MGS-TOU, the Rate Design Panel noted that DEP is willing to balance lowering energy and demand, as appropriate, to meet the revenue requirement; ensure that it treats both low load factor and high load factor customers equitably; and provide that rate change shifts occur gradually. *Id.* at 271. The Rate Design Panel also testified that DEP agrees with witness Chriss that demand charges should align with demand-related costs. *Id.* at 276. However, the Rate Design Panel explained that DEP must also balance alignment to cost causation with gradualism. *Id.* at 277. As such, the Rate Design Panel testified that DEP's proposed rates, which reflect higher fixed cost recovery through demand charges, result in improved alignment to cost-of-service while also including necessary gradualism in order to avoid potential adverse impacts to lower load factor customers. *Id.*

Additionally, the Rate Design Panel rebutted witness Nelson's argument that DEP should increase cost recovery through energy charges and correspondingly decrease demand charges for Schedules MGS-TOU and LGS-TOU. *Id.* at 272. The Rate Design Panel explained that contrary to witness Nelson's recommendation, DEP proposed a modest increase in fixed cost recovery through demand charges relative to such recovery through energy charges. *Id.* The Rate Design Panel testified that DEP's proposal to increase cost recovery through demand charges both improves alignment to cost-of-service and provides meaningful price signals to encourage system beneficial behavior. *Id.* The Rate Design Panel explained that witness Nelson's suggestion would penalize higher load factor customers, who more consistently use fixed assets and require less cost to serve per unit of energy, and thus increase subsidization between customers with varying load factors. *Id.* at 273. The Rate Design Panel further explained that witness Nelson's proposed rate design would encourage more consistent consumption reduction throughout the month and weaken price signals that are meant to reduce consumption at peak times, thereby increasing the strain on the grid and subsequently increasing the

need for investments, ultimately increasing costs for all customers. *Id.* at 274. In contrast, the Rate Design panel testified that DEP's proposed rate design would encourage targeted behavioral modification to reduce demand during the times when additional demand would drive more fixed cost investments. *Id.*

Further, in response to witness Nelson's recommendation that DEP adopt a CPP rate option for MGS and LGS customers, the Rate Design Panel claimed that a CPP rate was unnecessary. *Id.* at 276. The Rate Design Panel noted that during the CRDS, stakeholders generally favored new hourly pricing options relative to CPP options. *Id.* Additionally, the Rate Design Panel stated that DEP's MGS and LGS rate design proposals offer suitable and sufficient options for customers with flexible loads. *Id.*

The Rate Design Panel also testified that it disagreed with witness O'Donnell's recommended changes to DEP's Mid-Peak Demand Charge and Base Demand Charge under Schedule LGS-TOU. *Id.* at 277-79. The Rate Design Panel explained that DEP's proposed Mid-Peak Demand Charge plays an important role in collecting significant amounts of fixed costs associated with non-peak production and transmission assets. *Id.* at 278. Similarly, the Rate Design Panel testified that the Base Demand Charge is carefully designed to reflect certain system costs under the CDM and to recover costs for distribution assets that remain constant year-round and are close to the customer, and thus appropriately utilizes a ratchet. *Id.* The Rate Design Panel explained that customers that exhibit consistent loads year-round, including some manufacturing customers, benefit from the ratchet feature because demand charges would be higher overall without such a feature. *Id.* at 278-79. Moreover, as witness Byrd testified during the hearing, the Base Demand Charge reduces bill volatility for customers by allocating and recovering costs through "very consistent charges". *Id.* at 364-65. The Rate Design Panel also disagreed with witness O'Donnell's characterization of the LGS-TOU rate as overly complex because customers taking service under Schedule LGS-TOU are generally sophisticated and capable of understanding rate design. *Id.* at 279. Moreover, as described in the CRDS, DEP's proposed tariffs appropriately balance simplicity and understandability with alignment to cost-of-service. *Id.*

DEP, the Commercial Group, and Kroger Co. and Harris Teeter entered into the MGS Partial Rate Design Stipulation resolving some of the issues in this proceeding between the parties. The MGS Partial Rate Design Stipulation provides that 75.0% of the reduction in revenue requirement, as determined by final Commission order, applicable to Rate Schedule MGS-time-of-use (TOU), should be applied to energy rates. The MGS Partial Rate Design Stipulation also provides that Kroger Co. and Harris Teeter agree to withdraw its proposal that DEP study the possibility of, and propose, a multi-site aggregate commercial rate. Finally, the MGS Partial Rate Design Stipulation provides that Kroger Co. and Harris Teeter does not oppose the Revenue Requirement Stipulation or the PIMs Stipulation.

DEP and CIGFUR entered into the LGS Partial Rate Design Stipulation, resolving some of the issues in this proceeding between the parties. The LGS Partial Rate Design Stipulation provides that any increase in energy charges resulting from an increase in

DEP's revenue requirement to be recovered from the LGS, LGS-TOU, and LGS-Real Time Pricing (RTP) rate schedules, as determined by final Commission order, shall be limited to a percentage that is less than half of the approved overall increase percentage to the LGS, LGS-TOU, and LGS-RTP classes, respectively, exclusive of any decrements for the LGS, LGS-TOU, and LGS-RTP rate schedules. The LGS Partial Rate Design Stipulation also applies to any customers currently taking service under an LGS, LGS-TOU, or LGS-RTP rate schedule that switch tariffs to either the High Load Factor tariff or Hourly Pricing (HP) tariff, in the event the Commission approves such tariffs in this proceeding.

Schedule LGS-RTP is a historical rate option that provides DEP's LGS customers with exposure to marginal pricing above a Customer Baseline Load (CBL) threshold. Tr. vol. 11, 251. Schedule LGS-RTP is currently available to customers with a load of 1,000 kW or greater and is capped at 85 nonresidential customers. *Id.* In his direct testimony, DEP witness Byrd testified that DEP proposes to freeze Schedule LGS-RTP to new applicants but grandfather current customers. *Id.* Specifically, witness Byrd testified that DEP will close Schedule LGS-RTP to new applications beginning October 1, 2023, and discard the waitlist to join schedule LGS-RTP. *Id.* at 338-39. Witness Byrd explained that DEP proposes to freeze Schedule LGS-RTP because it is administratively burdensome and does not contain ongoing CBL adjustments, creating scalability issues by allowing incremental load to remain on marginal pricing indefinitely. *Id.* at 251.

Additionally, witness Byrd testified that freezing Schedule LGS-RTP is appropriate considering the new Schedule HP proposed by DEP. *Id.* Witness Byrd explained that DEP created Schedule HP in response to stakeholder and customer requests during the CRDS for a more flexible marginal price rate with expanded availability. *Id.* at 248. Like the LGS-RTP, witness Byrd stated that Schedule HP will be available to customers with a load of 1,000 kW or greater. *Id.* at 249. Under Schedule HP, DEP will reestablish the CBL, which defines the level above which DEP will bill all kWh at the hourly energy prices, every four years based on a customer's 12-month usage history, with modifications to reflect price-responsiveness during times of grid constraints. *Id.* at 249. Witness Byrd explained that this new approach to reestablishing CBLs will restrict marginal prices to only four years for growing loads that are not consistently price-responsive, resulting in embedded cost recovery from such loads after the periodic CBL reestablishment. *Id.* Witness Byrd stated that the newly proposed CBL management is average kW and kWh by TOU period. *Id* at 250. Schedule HP will include a margin adder of $6.00 per megawatt-hour to account for day-ahead pricing uncertainty and provide some fixed cost recovery from the marginal energy purchases. *Id.* Witness Byrd testified that DEP proposes Schedule HP without a participation cap due to the durability and scalability of the new program design. *Id.*

DoD-FEA witness Blank recommended that the Commission deny DEP's request to freeze the LGS-RTP rate because DEP has not demonstrated a need to close the rate. Tr. vol. 21, 336-37, 341. Witness Blank testified that LGS-RTP is fully subscribed and that by freezing the rate DEP would prevent the possibility of a new customer replacing a departing LGS-RTP customer, which may provide a "financial windfall" to DEP. *Id.* at 336. Additionally, witness Blank argued that DEP should not close LGS-RTP because

Schedule HP is "categorically different" from Schedule LGS-RTP and therefore is not a suitable replacement for the LGS-RTP tariff. *Id.* at 336, 338. Witness Blank did not express any concerns with Schedule HP. *Id.* at 337-38.

In rebuttal, the Rate Design Panel disputed witness Blank's recommendation that the LGS-RTP rate should remain open. Tr. vol. 11, 284-88. In response to witness Blank's concerns that a departing LGS-RTP customer could provide a windfall to DEP, the Rate Design Panel testified that it does not anticipate that an existing RTP customer would switch to a non-RTP rate because under such scenario, a customer would be voluntarily switching to a higher rate. *Id.* at 285. The Rate Design Panel explained that witness Blank's imagined scenario is unrealistic because customers taking service under LGS-RTP are generally sophisticated and large and would not normally leave the rate for a less attractive option. *Id.* Rather, the Rate Design Panel testified that to the extent attrition occurs on LGS-RTP, the customer would likely be leaving DEP's service territory or otherwise switching to a lower-cost rate, thus lowering DEP's revenues. *Id.*

The Rate Design Panel also disagreed with witness Blank that Schedule HP is not a suitable substitute for LGS-RTP. *Id.* The Rate Design Panel testified that several similarities exist between Schedule LGS-RTP and Schedule HP. *Id.* Specifically, the Rate Design Panel stated that both the LGS-RTP tariff and Schedule HP: (1) are available to customers with a load of 1,000 kW or greater; (2) have energy priced at a marginal rate above a CBL threshold; and (3) contain incremental demand charges and an incentive margin. *Id.* at 285-86. Furthermore, the Rate Design Panel stated that the differences between LGS-RTP and Schedule HP demonstrate that Schedule HP is superior to LGS-RTP. *Id.* at 286. For instance, since under Schedule HP DEP will reestablish CBLs every four years and reduce them using a method that recognizes the benefits of price-responsiveness during times of grid constraints, loads DEP presently serves under the CBL could have exposure to marginal pricing after consistent price-responsive behaviors—a customer benefit that does not exist under the LGS-RTP tariff. *Id.* at 286. The Rate Design Panel explained that these adjustments are appropriate because loads that customers can reduce during times of system peak consistently over several years reduce the need for additional peaking resources and lower costs overall for the grid. *Id.* Similarly, a CBL reestablishment every four years ensures that loads that are not price responsive eventually move under the CBL and receive pricing under embedded costs, which is appropriate as such loads begin to drive investments in additional capacity assets. *Id.* at 286-87. Additionally, because of the reduced administrative burden and four-year CBL reestablishment, the Rate Design Panel testified that DEP was able to offer Schedule HP without a participation cap. *Id.* at 287. Finally, the Rate Design Panel explained that Schedule HP will more effectively serve as an economic development tool than the LGS-RTP tariff since Schedule HP is not capped and thus prospective new customers can confidently expect to be able to sign on to the rate if they wish to do so. *Id.* In summary, the Rate Design Panel stated that while several core elements in Schedule HP mirror Schedule LGS-RTP, the proposed improvements in Schedule HP relative to the LGS-RTP tariff yield a more scalable, durable, and accessible rate option for customers. *Id.* at 287-88.

During the expert witness hearing, witness Reed elaborated on the administrative burdens associated with Schedule LGS-RTP. *Id.* at 381-85. Specifically, witness Reed explained that Schedule LGS-RTP requires creation of a CBL and calendar mapping that reflect an individual customer's operations. *Id.* at 381-82. Witness Reed testified that under such processes, DEP sets a CBL for every hour of every day in Excel and must then update this data both annually and every time there is a change in scheduled shutdown days. *Id.* at 381-82. Witness Reed also described the administrative burden of manually billing and calculating the RTP bill for customers. *Id.* at 382. Witness Reed further noted that it takes two full-time personnel to manage Schedule LGS-RTP. *Id.* In contrast, witness Byrd testified that Schedule HP is much simpler and more scalable than Schedule LGS-RTP. *Id.* at 385. For example, witness Byrd explained that Schedule HP uses a CBL management approach that is already in place for DEC's hourly pricing program. *Id.* at 250, 385. This process of CBL management will eliminate the need for the administratively burdensome calendar mapping and special days process currently in use for the existing RTP rate. *Id.* at 250. Instead, after establishment of an initial CBL, DEP will automatically reestablish every four years. *Id.*

At the reconvened hearing on July 24, 2023, Public Staff witness D. Williamson testified regarding the Public Staff's concerns with the LGS Partial Rate Design Stipulation. Specifically, Public Staff witness D. Williamson testified that the Public Staff opposes the stipulation on the basis that it constricts the rate designer's ability to appropriately figure out how the revenue requirement that would get assigned to that class should be allocated between the energy and demand components of the rates. Tr. vol. 24, 89. He testified that while the stipulation might move in alignment with the cost of service, the stipulation, in the Public Staff's position, inappropriately predetermines how cost is apportioned between energy and demand components. *Id.* He explained that rate designers, not parties to the proceeding, should apportion costs among the various components of rates as rate designers have a better understanding of load shapes individual classes, specifically with respect to all customers in the class. He explained the Public Staff's position that, for this reason, the rate designer is in the best position to adequately price energy, demand, the customer charges. *Id.* at 92- 93. Ultimately, he concluded that the rate designer is in the best position to ensure that rates are designed to recover costs from customer classes most in alignment with the costs incurred by the utility to serve each class. *Id.* at 94. He also concluded that rates designed to be in alignment with cost causation are just and reasonable. *Id.* at 95. Ultimately, he testified that the Public Staff recommends that the Commission not approve the stipulation in order to allow rate designers to do their work. He testified that if the rate designer reaches the same conclusion on rate design as that set forth in the stipulation, then the Public Staff would support it. *Id.* at 97.

DEP witness Byrd testified that the LGS Partial Rate Design Stipulation would not involve any interclass subsidy and that the dynamic of allocating the revenue requirement between the energy and demand components of the rate impacts only the specific rate schedule for the customer class. *Id.* at 74. DEP witness Byrd testified that the possibility of moving capacity-related costs to the demand component of the rate was discussed during the Comprehensive Rate Design process. He testified that:

> At a high level, [DEP] looked at cost of service and determined that it would be appropriate to increase the amount of fixed costs recovered through demand charges relative to energy. We wrote about that in the roadmap, and so the Company proposed in this case -- our original proposed rates, particularly for LGS-TOU, increased the amount of fixed cost recovery through demand charges.

Id. at 75.

DEP witness Byrd testified that while the stipulation would not result in any interclass subsidization, there might be a slight bill impact to customers within the class, based on load factor but this impact is in alignment with cost of service. *Id.* at 77-78, 83-84. CIGFUR II witness Collins confirmed that the LGS Partial Rate Design Stipulation would not cause an interclass subsidy. Tr. vol. 24, 72.

Considering the parties' testimony and the evidence the parties presented, the Commission concludes that DEP's proposed rate design for the MGS and LGS rate classes, including the modifications agreed to in the MGS Partial Rate Design Stipulation and the LGS Partial Rate Design Stipulation, is just and reasonable. The Commission concludes that DEP's proposed Basic Customer Charge increases, including Basic Customer Charges of $30.00 for the MGS class and $210.00 for the LGS class, strike an appropriate balance that provide rates that accurately reflect cost causation, minimize subsidization, and provide proper price signals to customers in the MGS and LGS rate classes, while also moderating the impact of such increase on lower-load factor customers.

In addition, the Commission concludes that the MGS Partial Rate Design Stipulation and LGS Partial Rate Design Stipulation are the products of arm's-length negotiations between parties who took opposing positions on these subjects in their prefiled testimony. The Commission also finds that the MGS Partial Rate Design Stipulation and LGS Partial Rate Design Stipulation reduce the number of contested issues the parties present to the Commission for resolution regarding rate design. Both stipulations address only intra-class issues, not inter-class issues, and focus on increasing the amount of fixed cost recovery through demand charges as opposed to energy, which is consistent with DEP's COSS. The Commission acknowledges the concern of the Public Staff regarding rate design and the preference that the rate designer not be constrained by agreements between the utility and certain customers regarding the apportionment of costs between demand and energy components of the rates. Specifically, the Commission takes note of the concern that this may give rise to "winners and losers" within a particular customer class and appreciates the Public Staff's vigilance for all customers within a class. The Commission is persuaded by DEP witness Byrd that the LGS Partial Rate Design Stipulation does not result in an interclass subsidy and impacts customers within the class only slightly and in a manner that aligns with cost causation. The Commission notes that no party presented any evidence that the MGS Partial Rate Design Stipulation results in any interclass subsidization, involves inter-class allocation of revenue requirement, or is not in alignment with DEP's COSS. Therefore,

the Commission concludes that the MGS Partial Rate Design Stipulation and LGS Partial Rate Design Stipulation are reasonable and should be approved. However, in recognition of the concerns raised by the Public Staff, the Commission approval in this proceeding shall not be taken as an indication that the Commission generally looks favorably on rate design settlements, and the Commission will scrutinize rate design settlements between the utility and any customer or customer group going forward, with the objective of achieving just and reasonable rates for all customers.

Testimony from witnesses Reed, Byrd, Bieber, and Chriss indicates that the change to the MGS-TOU rate design agreed to in the MGS Partial Rate Design Stipulation is reasonable and based on cost causation. The Commission notes that the Partial Rate Design Stipulation provision relating to MGS-TOU energy rates applies only to the MGS-TOU rates proposed in this rate case. This provision does not bind DEP to any particular rate design structure in future rate cases and does not limit its ability to study alternative rate designs. Furthermore, testimony from witnesses Reed, Byrd, and Phillips indicates that the change to the LGS rate design agreed to in the LGS Partial Rate Design Stipulation is reasonable and based on cost causation. The Commission observes that the LGS Partial Rate Design Stipulation provision relating to LGS energy rates applies only to the LGS, LGS-TOU, and LGS-RTP rates proposed in this rate case, and any customers currently taking service under Rate Schedules LGS, LGS-TOU, or LGS-RTP that subsequently switch to either the HLF tariff or the HP tariff. This provision does not bind DEP to any particular rate design structure in future rate cases and does not limit DEP's ability to study alternative rate designs.

Additionally, the Commission concludes that DEP's proposal to freeze Schedule LGS-RTP to new customers effective October 1, 2023, is reasonable. The Commission further concludes that DEP's proposed Schedule HP is reasonable. The Commission declines to adopt witness Blank's recommendation to keep LGS-RTP open to new customers after DEP's proposed freeze date. Witness Reed offered convincing testimony that keeping LGS-RTP open is unduly burdensome and unnecessary given DEP's new Schedule HP. Accordingly, the Commission agrees with DEP that it is appropriate to freeze LGS-RTP. Additionally, the Commission rejects witness Blank's characterization of Schedule HP as "categorically different" than Schedule LGS-RTP. The Commission concludes that though Schedule LGS-RTP and Schedule HP contain several core similarities the differences between the two rate schedules indicate that Schedule HP will be more effective and efficient than Schedule LGS-RTP.

The Commission declines to adopt witness Nelson's recommended modifications to DEP's proposed MGS and LGS rate designs. The Rate Design Panel offered convincing testimony that it is appropriate to increase the level of fixed costs recovered through demand charges in this proceeding since doing so will improve alignment to cost causation across the range of customer load factors while also providing meaningful price signals. In contrast, the Commission finds that witness Nelson's proposal will likely result in subsidization between customers with varying load factors and weaken price signals. The Commission also rejects witness Nelson's request that the Commission adopt a CPP

rate at this time given the design of the MGS-TOU and LGS-TOU rates and the introduction of new hourly pricing options.

The Commission also declines to adopt the recommendation of witness O'Donnell to remove the Mid-Peak Demand Charge and the ratchet from the Base Demand Charge on the grounds that these charges are based on a rate design that more accurately reflects DEP's cost of service and provides customers with flexible loads the opportunity to shift consumption patterns and reduce costs.

Small General Service (SGS)

The SGS rate class includes all nonresidential customers with demand requirements below 30 kW and consists of the following rate schedules: SGS, SGS-TOUE, and SGS-TOU-CPP. Tr. vol. 11, 188.

In her direct testimony, DEP witness Reed described the proposed rate design for the SGS rate schedules. *Id.* at 188-89. Witness Reed testified that DEP is proposes to increase the Basic Customer Charge for the SGS class to better reflect the cost of serving these customers. *Id.* at 189. Specifically, witness Reed stated that DEP proposes to increase the Basic Customer Charge for the SGS class for all rate years from $21.00 to $22.00 per month for all SGS schedules to minimize the percentage increase in bills for customers with low monthly usage and to maintain a similar overall proposed increase for customers within the SGS class. *Id.* Witness Reed testified that DEP proposes to keep the Base Customer Charge at $22.00 per month for all rate years. *Id.* Witness Reed also testified that DEP proposes retaining the current kWh energy block structure, with the second block being approximately 18.0% less than the first block kWh energy rate. *Id.* Witness Reed stated that SGS energy rates are adjusted to recover the requested revenue increase. *Id.*

In his direct testimony, AGO witness Nelson recommended that DEP revise Schedule SGS-TOU-CPP. Tr. vol. 18, 105-06. Witness Nelson claimed that as currently designed, Schedule SGS-TOU-CPP does not appear to provide any tangible benefit in comparison to DEP's default TOU option under Schedule SGS-TOUE and, that in fact, Schedule SGS-TOU-CPP would be costlier for customers. *Id.* Witness Nelson claimed that Schedule SGS-TOU-CPP has higher rates across every time period, serving as a strong disincentive for customers to enroll and provide grid services during critical peak events. *Id.* at 106. He testified that DEP had previously acknowledged that "there is a pricing concern with SGS-TOU-CPP" and that as of February 2023 only a single customer had enrolled in the tariff. *Id.* As such, witness Nelson argued that DEP should redesign SGS-TOU-CPP so that customers who opt for the rate over the default TOU option have opportunities to save if they respond appropriately to critical peak events. *Id.*

DoD-FEA witness Blank also testified regarding DEP's proposed rate increase for the SGS class. Tr. vol. 21, 323. Specifically, witness Blank recommended that DEP maintain its proposed rate increase for the SGS class at $469,000 or 8.16%. *Id.*

In their rebuttal testimony, the Rate Design Panel acknowledged that there is a pricing concern with SGS-TOU-CPP. Tr. vol. 11, 282. As such, the Rate Design Panel stated that DEP will adjust the pricing on SGS-TOU-CPP to be more competitive relative to Schedule SGS-TOUE to encourage adoption of the more dynamic tariff. *Id.* Regarding witness Blank's recommendation on the proposed increase to the SGS class, the Rate Design Panel testified that witness Blank's rate increase proposal would shift the rate increase from the LGS class to other classes, contrary to DEP's goals of alignment to cost causation, gradualism and the avoidance of rate shock. *Id.*

Considering the parties' testimony and the evidence presented, the Commission concludes that DEP's proposed rate design for the SGS class, subject to modification in its compliance filing, is just and reasonable. The Commission concludes that DEP's proposed Basic Customer Charge increase to $22.00 per month for all SGS schedules strikes an appropriate balance that provides rates that accurately reflect cost causation and thus, minimizes subsidization and provides proper price signals to customers in the SGS customer class. Additionally, the Commission agrees with the Rate Design Panel that DEP should make a compliance filing to adjust the pricing on SGS-TOU-CPP to be more competitive and to encourage adoption of the tariff. Further, the Commission declines to adopt witness Blank's proposed revenue adjustments to the SGS class because his proposal would result in greater subsidization and does not align with the principles of gradualism or cost causation.

Lighting

DEP provides outdoor lighting service under the following rate schedules: Area Lighting Service Schedule ALS, Street Lighting Service Schedule SLS, and Street Lighting Service (Residential Subdivisions) Schedule SLR. Tr. vol. 11, 198. DEP also provides lighting service under Sports Field Lighting Service Schedule SFLS, Traffic Signal Service (Metered) Schedule TFS, and Traffic Signal Service Schedule TSS. *Id.* at 197.

In her direct testimony, DEP witness Reed testified in support of DEP's proposed changes to its Lighting class schedules. *Id.* at 197-202. With respect to outdoor lighting, witness Reed testified that DEP has adjusted the rates in the proposed outdoor lighting schedules to achieve a combined outdoor lighting revenue target and to reduce or eliminate the difference between the monthly rates in the Area and Street Lighting Service Schedules for similar fixtures and poles/posts. *Id.* at 198. Witness Reed explained that because the current SLS class has a significantly lower return than DEP realizes under Schedule ALS, DEP recommends a higher increase for Schedules SLS and SLR. *Id.* Witness Reed also testified that DEP proposes to freeze Schedule SLR to new applicants to align with DEC's outdoor lighting offering. *Id.* at 201. Witness Reed explained that DEP will continue to serve existing customers under Schedule SLR until such time as they move to another schedule and new customers can take service under Schedules SLS or ALS, as applicable. *Id.*

In their direct testimonies, NCLM witnesses Saffo and Mann testified that DEP's proposed increases for the Lighting class are far too high and have the potential for rate

shock. Tr. vol. 21, 761-62, 765, 777-78, 783. Witness Mann testified that the proposed increases for Lighting class customers are almost triple the average increase in the base rate, and almost double the average increase across the MYRP period. *Id.* at 762. Witness Mann also asserted that DEP's proposed Lighting class rate increases will force municipalities in North Carolina "to choose between cutting services and programs or raising property taxes on citizens," since one of the most significant costs for municipalities is street lighting. *Id.* at 766. Witness Saffo described DEP's 30.0% rate increase to the Lighting class over three years as "the opposite of gradual". *Id.* at 779. Witnesses Saffo and Mann requested that the Commission carefully review proposed rate increases for services to municipalities to be assured that DEP has taken all steps to minimize any rate increases. *Id.* at 765, 783.

In his direct testimony, Public Staff witness D. Williamson recommended approval of DEP's proposed changes to Schedule SLR, including the accompanying amendments to its Outdoor Lighting Service Regulations. Tr. vol. 20, 176-77. However, witness D. Williamson recommended that DEP notify all Schedule SLR customers of this change by bill insert or separate mailing. *Id.* at 177.

In their rebuttal testimony, the Rate Design Panel recognized that the Lighting class is facing a large rate increase but explained that a change in cost-of-service methodology primarily drives the proposed increase. Tr. vol. 11, 283-84. The Rate Design Panel testified that to mitigate some of the increase, DEP proposes to limit the reduction in the subsidy to 10.0% as opposed to the 25.0% it implemented in prior rate cases, resulting in a 19.9% increase instead of a 24.9% increase for the Lighting class. *Id.*

Regarding Public Staff witness D. Williamson's recommendation regarding Schedule SLR, the Rate Design Panel testified that DEP is willing to notify all Schedule SLR customers of its proposal to freeze the rate schedule, including the accompanying amendments to DEP's Outdoor Lighting Service Regulations, via bill insert or separate mailing. *Id.* at 284.

During the expert witness hearing, DEP witness Reed reiterated that the COSS indicated that the Lighting class should have received a substantial increase. Tr. vol. 12, 16. To mitigate this increase to the lighting class, witness Reed stated that DEP is proposing to reduce the subsidy reduction to 10.0%. *Id.* Witness Reed explained that the reduction from 25.0% to 10.0% amounts to approximately $4 million in savings to the lighting class. *Id.* While witness Reed acknowledged the substantial rate increase to the Lighting class, she explained that DEP needs to recover its revenue requirement and that DEP has limited options to shift these costs to other customer classes. *Id.* at 18. Witness Reed explained that, to the extent possible, she levelized the rate increase between the rate schedules within the lighting class. *Id.*

Considering the parties' testimony and the evidence the parties presented, the Commission finds that DEP's proposed rate design for the Lighting class, with the modification Public Staff witness D. Williamson suggested and DEP agreed to, is just and reasonable for the purposes of this proceeding. The Commission concludes that the rate

increase for the Lighting class is due to the change in cost-of-service methodology and, while substantial, reflects actual cost causation. As such, while the Commission gives some weight to the testimony of NCLM witnesses Saffo and Mann and acknowledges that the rate increase to the Lighting class may prove to be burdensome, it also recognizes the need for rates to reflect cost causation and thus approves DEP's proposed rate design for the lighting class.

Service Riders

In his direct testimony, DEP witness Byrd described DEP's proposed new service riders – Economic Development Rider (Rider EC) and Non-Residential Solar Choice Rider (Rider NSC) – that DEP intends to offer so it may expand the rate options available to customers. Tr. vol. 11, 230. Witness Byrd testified that proposed Rider EC and Rider NSC stemmed from discussions with stakeholders during the CRDS. *Id.* at 247, 253.

Witness Byrd testified that Rider EC will be available to customers: (1) with new load exceeding 1,000 kW with a minimum load factor of 40.0%; (2) that have applied for and received economic assistance from either the state or local government or another public agency; and (3) that meet certain employment and investment minimums relative to the size of the new load. *Id.* at 253. However, witness Byrd stated that new loads that are predominantly for serving EV charging are exempted from Rider EC's employment and load factor requirements and may participate for new load sizes above 500 kW, and that existing customers considering plant investments with possible relocation outside of DEP's service territory may qualify for Rider EC by meeting the investment and employment thresholds, but their new load calculation will exclude reductions associated with the removal of historic equipment or processes. *Id.* at 253-54. Witness Byrd stated that in light of new Rider EC, DEP proposes to close its existing Economic Development Rider (Rider ED) and Economic Redevelopment Rider (Rider ERD) to new applicants. *Id.* at 257. Witness Byrd explained that customers DEP currently serves under Rider ED and Rider ERD will continue to take service under these riders until completion of their existing contracts. *Id.*

Witness Byrd testified that Rider EC contains several improvements to Rider ED. *Id.* at 254-55. First, witness Byrd explained that Rider EC will provide more flexibility for customers to tailor benefits based on both electric grid and regional economic benefits associated with the participant's investment and load characteristics. *Id.* at 252-53. For example, Rider EC will consider the following criteria in developing appropriate benefit levels on an individual customer basis: peak monthly demand; average monthly load factor; DEP's incremental costs to serve; the number of new full-time employees; economic multiplier; and the total new capital investment of the customer. *Id.* at 254. Second, witness Byrd testified that in contrast to Rider ED, under which participants are required to begin taking credits 18 months after the first date service is supplied under the contract (the ramp up period), Rider EC allows participants to wait to take credits until 36 months after the first date of service, recognizing that some industries require significant start-up time for new facilities and that an 18-month ramp up period may constrain their ability to take advantage of Rider EC's benefits. *Id.* at 254-55. Third, witness Byrd testified that unlike Rider ED, which provides benefits that steadily decline

over a five-year period on a rigid schedule, Rider EC allows benefits up to 10 years, with possible differences across the years as determined by the project merits. *Id.* at 255. For example, witness Byrd stated that DEP will require projects receiving greater levels of benefits for longer periods to meet higher thresholds of investment and employment. *Id.* Finally, witness Byrd explained that Rider EC provides a reduction of up to 75.0% of the applicable demand charges on the monthly bill, while Rider ED provides a reduction in demand charges that would require modification in order to align it with DEP's proposed demand charge structure redesign. *Id.* Overall, witness Byrd explained that Rider EC will enable DEP to improve its ability to compete for, attract, and retain customers that are adding jobs and making capital investments in its service territory, ultimately reducing the prices all customers pay and promoting the prosperity of the citizens and businesses in North Carolina. *Id.* at 252-53, 255-56.

With respect to Rider NSC, witness Byrd testified that, as a result of DEP's proposed new TOU periods and the new three-part demand charge structure, DEP proposes new Rider NSC to implement several changes for non-residential customers who seek to pursue self-generation through NEM. *Id.* at 246. Witness Byrd stated that to be eligible for Rider NSC, customers must take service under a general service rate schedule that includes TOU periods. *Id.* Witness Byrd explained that because DEP's TOU periods include the proposed modified demand charge structure, this eligibility requirement ensures price alignment with system utilization and cost causation. *Id.* at 246-47. Additionally, witness Byrd stated that Rider NSC will be available to customers with NEM systems that do not exceed the lesser of 100.0% of the customer's contract demand or 5,000 kW. *Id.* at 247. Moreover, under Rider NSC, DEP proposes eliminating the standby charge for customers with a capacity factor of 60.0% or less. *Id.* Finally, unlike Rider NM, energy exported would be netted against imports during the same TOU period and excess energy exported would be credited at an average avoided cost rate calculated using the Net Energy Credit calculation proposed by DEC and DEP in Docket No. E-100, Sub 175. *Id.*

With the advent of Rider NSC, witness Byrd testified that DEP is proposing that all new non-residential NEM applications take service under Rider NSC and that current Rider NM be frozen to new customers beginning on October 1, 2023. *Id.* at 248. Accordingly, witness Byrd explained that only existing non-residential NEM customers served under Rider NM prior to the availability of Rider NSC would continue service under Rider NM. *Id.* Witness Byrd stated that existing NEM customers could continue service under Rider NM until they request service under Rider NSC or until September 30, 2033, at which point all non-residential NEM customers receiving service under Rider NM will be moved to Rider NSC or another appropriate tariff, as available at that time. *Id.*

In his direct testimony, Public Staff witness Nader testified that Rider EC is in the public interest and not unduly discriminatory, will assist in preventing job loss. and fairly balances costs and benefits. Tr. vol. 21, 104-06. Witness Nader explained that Rider EC mitigates the potential for further loss of economic activity in communities that the state has already designated as economically distressed by targeting new investment in load, employment, and economic activity. *Id.* at 104-05. Witness Nader also stated that

requiring participants to demonstrate that they have received state or local assistance conveys a sense of fairness between the costs to non-participants and the benefits to participants. *Id.* at 105. Moreover, witness Nader testified that the retention of jobs is critical given the competitive pressures manufacturing and large energy customers experience, and Rider EC should assist with keeping jobs in economically distressed communities. *Id.* Witness Nader also noted that Rider EC's longer ramp-up period and extended period of access should help ensure that system load and employment will remain in communities for some time. *Id.* Finally, witness Nader testified that the Public Staff is "reasonably satisfied" that the costs and benefits of Rider EC are balanced and fair. *Id.* at 106. However, to ensure that Rider EC continues to be in the public interest, witness Nader recommended that the Commission require annual reporting of the impacts of Rider EC. *Id.* At a minimum, witness Nader stated that DEP should report the gross level of incentives paid, the number of recipients, the amount of investment, load, and jobs associated with the incentives, and an overall marginal cost analysis of Rider EC to determine if the gross level of incentives paid exceeds the marginal cost to serve the gross pool of participants. *Id.*

With respect to Rider NSC, Public Staff witness Nader recommended that DEP's proposed 5,000 kW cap on installed capacity be eliminated. *Id.* at 108. Witness Nader testified that by requiring all non-residential NEM customers to subscribe to a TOU schedule and the proposed three-part demand structure, the full fixed cost of service should be recovered regardless of system size, thereby mitigating the risk for material cross-subsidization. *Id.* Witness Nader also argued that large non-residential customers that seek to install on-site generation will be subject to the capital funding limitations of their own businesses, serving as another limitation to prevent generation in excess of site load from being installed. *Id.* at 108-09. Although witness Nader found DEP's concerns regarding reliability if the installed capacity limit were increased to be valid, but he testified that these concerns could be addressed though customer generator controls and communication. *Id.* at 109.

Regarding Rider NSC. AGO witness Nelson recommended that: (1) customers have the option to enroll in Rider NSC for a contract term of up to five years, with the option for annual renewal thereafter; and (2) DEP permit customers enrolling in a rate that does not include a demand charge to retain their renewable energy credits (RECs). Tr. vol. 18, 108. Witness Nelson explained that providing an option for customers to enroll for a term length of up to five years balances the need to provide customers with rate certainty with the imperative to ensure that tariffs adapt to reflect evolving grid dynamics. *Id.* at 108-09. Additionally, witness Nelson argued that DEP's requirement that customers who do not enroll in rates containing a demand charge cede RECs to DEP appears arbitrary and would unduly harm or discourage the participation of SGS customers who do not currently have the option of enrolling in demand-based rates. *Id.* at 110.

Although not raised by DEP in this proceeding, Public Staff witness D. Williamson recommended that DEP analyze the standby service being offered under Riders 7 and 57 in his direct testimony. Tr. vol. 20, 178-79. Witness D. Williamson claimed that the rates and terms of service under Riders 7 and 57 likely do not cover the costs incurred to serve

customers. *Id.* at 178. Additionally, witness D. Williamson argued that keeping Riders 7 and 57 – which only serve five large industrial customers – closed to all other customers and allowing only five customers to benefit results in an unduly discriminatory rate design. *Id.* Therefore, witness D. Williamson recommended that the Commission require DEP, prior to filing its next rate case or PBR application, to analyze the impact of transferring the five customers currently taking service under Riders 7 and 57 to other standby service riders. If the analysis shows that viable options to do so exist, witness D. Williamson recommends that DEP propose a transition period in its next general rate case or PBR proceeding to temper any potential rate shock that doing so may cause the customers currently taking service under Riders 7 and 57. *Id.* at 179.

On rebuttal, the Rate Design Panel testified that it did not agree with Public Staff witness Nader's recommendation for elimination of the 5,000 kW cap on Rider NSC. *Id.* at 291. The Rate Design Panel explained that the 5,000 kW limit strikes a reasonable balance between stakeholders' requests during the CRDS for larger system sizes and DEP's concerns regarding grid operations and reliability. *Id.* The Rate Design Panel noted that DEP's proposed 5,000 kW limit for Rider NSC represents a 500.0% increase over Rider NM. *Id.* Moreover, the panel testified that DEP's proposed Schedule HP would allow customer generating systems above the 5,000 kW limit for Rider NSC. *Id.* Importantly, the Rate Design Panel explained that the larger the NEM system, the more complicated the interconnection study due to the of the unpredictability of their output to the grid. *Id.* DEP witness Byrd, during the expert witness hearing, testified that the sort of unpredictability in output (which becomes a bigger problem in the context of larger systems) has the potential to create large swings in load, which poses reliability challenges. Tr. vol. 12, 32. Accordingly, given the sizable move from 1,000 kW to 5,000 kW and operational considerations associated with going beyond 5,000 kW, witness Byrd testified that DEP believes it is inappropriate to remove the cap. *Id.* at 74.

In response to witness Nelson's recommendations with respect to Rider NSC, the Rate Design Panel testified that it did not agree with his recommendation. Tr. vol. 11, 292-93. Specifically, the Rate Design Panel explained that it did not agree with witness Nelson's recommendation that DEP permit customers to enroll in Rider NSC for a term of up to five years because DEP merely intends that the specific tariff language it proposes for Rider NSC – that "[t]he Customer shall enter into a contract for service under this Rider for a minimum original term of one (1) year, and the contract shall automatically renew thereafter . . . ." – correspond to and align with the core tariff language. *Id.* at 292. Additionally, the Rate Design Panel testified that it did not agree that DEP should permit its customers enrolling in a rate that does not include a demand charge to retain their RECs since DEP's retention of RECs from systems is a long-standing practice in North Carolina and DEP is not proposing any changes to this practice in this proceeding. *Id.* The Rate Design Panel further noted that currently effective Rider NM similarly requires DEP customers to cede RECs if they receive service under a schedule other than a TOU schedule with demand rates. *Id.* at 292-93.

Finally, in response to Public Staff witness D. Williamson's recommendation that DEP analyze the standby service DEP is offering under Riders 7 and 57, the Rate Design

Panel testified that the DEP does not oppose analyzing the effects to customers' bills of moving Riders 7 and 57 customers to another standby service rider or closing Riders 7 and 57 and moving customers to other available standby service options in a manner that lessens rate shock. *Id.* at 293.

During the expert witness hearing, DEP witness Byrd provided further support for Rider NSC. Witness Byrd testified that stakeholders discussed Rider NSC at length during the CRDS and that it captures stakeholders' proposals and feedback. Tr. vol. 11, 340-42, 347. Witness Byrd reiterated that Rider NSC better reflects cost causation. *Id.* at 351, 355. Witness Byrd, in response to questions from Commissioner Clodfelter, elaborated on DEP's justification for allowing it to retain RECs for customers who are not served under a TOU rate. Tr. vol. 12, 38-39. Witness Byrd explained that while DEP's Residential Solar Choice Rider (Rider RSC) allows customers to retain their RECs regardless of rate schedule, there are differences between Rider NSC and Rider RSC that justify the disparate treatment. *Id.* at 39. Specifically, witness Byrd stated that certain components of Rider RSC – e.g., CPP netting, non-bypassable charges, monthly grid access fee, and the monthly minimum bill – do not appear in Rider NSC and, therefore, the differences in REC retention are appropriate. *Id.*

DEP witness Byrd also provided further support for Rider EC during the expert witness hearing. In response to questions by Chair Mitchell, witness Byrd elaborated on the differences between Rider EC and Rider ED. Tr. vol. 12, 63. Witness Byrd testified that Rider EC is much more flexible than Rider EC and allows DEP to provide a more tailored incentive structure based on demand over a longer period. *Id.* Additionally, witness Byrd testified that Rider EC's 36-month ramp up period, as compared to the 18-month ramp up period under Rider ED, results in a more competitive offer to prospective customers considering sites in North Carolina. *Id.* at 63-64. Overall, witness Byrd testified that Rider EC is a more competitive and flexible offer that will put North Carolina in a better position to attract potential customers. *Id.* at 64-65.

Based on the evidence in the record, the Commission concludes that DEP's proposed new Rider EC, with the reporting obligation witness Nader suggested and DEP agreed to, is reasonable and should therefore be approved. The Commission views DEP's proposed Rider EC as an effort to attract economic development in North Carolina and concludes that implementation of the rider is in the public interest. As with other economic development tariffs this Commission has previously approved, approval of Rider EC is based in part on an evaluation of the expected economic benefits resulting from the tariff. The Commission has considered the goal of attracting new economic development in North Carolina as well as the impact of Rider EC on non-participating ratepayers and concludes that Rider EC strikes the appropriate balance between the two. The Commission agrees with witness Byrd that Rider EC will result in broad state and regional benefits by enabling DEP to assist North Carolina and local communities when competing for projects. The Commission gives substantial weight to the testimony of witness Byrd that Rider EC represents an improvement from Rider ED and that it is, therefore, appropriate for DEP to close existing Rider ED and Rider ERD.

The Commission also concludes, considering the evidence, that DEP's proposed new Rider NSC is reasonable and should therefore be approved. The Commission finds that Rider NSC is appropriate given DEP's new TOU periods and three-part demand structure and will help ensure price alignment with system utilization and cost causation. In arriving at this conclusion, the Commission gives weight to the testimony of DEP witness Byrd. The Commission is not persuaded by Public Staff witness Nader's recommendation that DEP eliminate the 5,000 kW cap on nameplate capacity. The Commission also gives weight to the operational and reliability concerns expressed by DEP. By increasing the cap from the existing 1,000 kW to 5,000 kW, DEP will gain more experience with larger systems, and this experience can be used to inform the Commission regarding the operational and reliability challenges and mitigative measures that can be adopted in future proceedings in the context of increasing the system limit. Therefore, the Commission rejects the Public Staff's recommendation to remove the 5,000 kW limit under Rider NSC. In addition, the Commission rejects the recommendations of AGO witness Nelson on the grounds that his proposals are inconsistent with past Commission practice. Finally, the Commission finds it reasonable to freeze Rider NM to new customers as of October 1, 2023, and allow existing NEM customers to continue service under Rider NM until they request service under Rider NSC or until September 30, 2033.

The Commission further requires before filing its next rate case, to DEP shall analyze the impacts of transferring customers receiving service under Riders 7 and 57 to other standby service riders and, if that analysis reveals viable options for transferring these customers, DEP shall move these customers to other standby service riders over a reasonable transition period and in a manner that lessens or avoids rate shock.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49-51

Cost of Capital

The evidence supporting these findings is in DEP's verified Application and Form E-1; the testimony and exhibits of the public witnesses; the testimony and exhibits of DEP witnesses Morin and Newlin, Public Staff witness Walters, CUCA witness O'Donnell, DoD-FEA witness Reno, NCJC, et al. witness Ellis, Commercial Group witness Chriss, CIGFUR witness Gorman; and the entire record in this proceeding.

Cost of Equity Capital

Summary of Evidence

DEP's rate of return expert, Dr. Roger Morin, recommended a rate of return on common equity of 10.4% with a capital structure consisting of 53.0% common equity and 47.0% debt. The recommendations of intervenor expert rate of return witnesses are as follows:

Witness Walters/The Public Staff	9.45%[10]
Witness O'Donnell/CUCA	9.25%[11]
Witness Reno/ DoD-FEA	9.3%
Witness Ellis/NCJC, et. al	6.00%

Neither Commercial Group witness Chriss, nor CIGFUR witness Gorman, performed an independent expert rate of return on common equity analysis. Rather, both witnesses confined their rate of return testimony to commenting on average rates of return awarded to electric utilities over various time periods.

As is often the case with rate of return on common equity, the testimony is voluminous. Below, the Commission summarizes the prefiled testimony of the various witnesses, and addresses testimony it received at the hearings in its discussion of its findings and conclusions.

DEP Direct and Supplemental Testimony

In his direct testimony, DEP witness Morin recapped the regulatory framework under which a regulated entity's rates should be set, which is that the entity should have a fair opportunity to recover its prudently incurred costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's required rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to permit a company the fair opportunity to earn a return commensurate with the cost of those funds. Tr. vol. 8, 31-32. Witness Morin noted that while the cost of debt is observable in the marketplace, the cost of equity – that is, investors' required rate of return on this source of financing – is more difficult to estimate. *Id.* Witness Morin concluded that the Commission's decision should allow DEP to earn a rate of return on common equity that is commensurate with returns on investments in other firms having corresponding risks; sufficient to assure confidence in DEP's financial integrity, and sufficient to maintain DEP's creditworthiness and ability to attract capital on reasonable terms. *Id.* at 32-34.

Witness Morin reiterated that the aggregate return required by investors is "the cost of capital," which he described as "the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the utility." *Id.* at 34. He noted further that public utilities (or their publicly traded parent companies) must compete for capital, and that the price of capital is set in the same manner as it is set for other input factors of production – by supply and demand. *Id.* at 35.

[10] Witness Walters recommends a 20-basis point downward adjustment in rate of return on equity, to 9.25%, if DEP's MYRP is approved, and 9.45% otherwise.

[11] Witness O'Donnell recommends a 25-basis point downward adjustment in rate of return on equity, to 9.0%, if the MYRP is approved, and 9.25% otherwise.

Witness Morin testified that the focus is and must be on the investor and the investor's expectations. As witness Morin explained, "[t]he market required rate of return on common equity, or cost of equity, is the risk-adjusted return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions in capital markets." *Id.* at 38.

In estimating a fair rate of return on common equity for DEP, witness Morin applied three cost of capital methodologies, the Discounted Cash Flow (DCF) methodology, the Capital Asset Pricing Model (CAPM) methodology, and the Risk Premium methodology, all of which are market-based methodologies designed to estimate the return required by investors on the common equity capital committed to DEP. *Id.* at 39. Witness Morin stressed that multiple methodologies must be employed in the estimation of the cost of equity. As he noted:

> No one single method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data.
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> * * *
>
> As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity.

Id. at 39-40.

He noted that the three methodologies he utilized, DCF, CAPM, and Risk Premium, are "broad market-based methods available to measure the cost of equity," and are all "accepted and used by the financial community and firmly supported in the financial literature." *Id.* at 40. Witness Morin utilized two sub-variants of each broad methodology, for a total of six studies.

In his direct testimony, witness Morin recommended a rate of return on common equity of 10.2%, which was the midpoint of the range of mathematical results from the six cost of capital studies he conducted. *Id.* at 26, 130. In his supplemental testimony, he updated all six of his studies, and provided the below comparison:

Method	Direct ROE	Supplemental ROE
DCF Value Line Growth*	9.9%	9.3%
DCF Analysts Growth*	9.3%	9.3%

CAPM*	10.8%	11.0%
Empirical CAPM*	11.1%	11.2%
Historical Risk Premium*	10.2%	10.8%
Allowed Risk Premium	10.2%	10.5%

* ROE estimate includes an adjustment for flotation costs.

Id. at 132. His updated rate of return on equity recommendation of 10.4% is again the midpoint of the range of these mathematical results.

For his supplemental testimony, witness Morin used the same proxy group as in his direct testimony, and the same methodologies in his studies as he had used in his direct testimony, but with updated capital markets data. The increase in his recommended rate of return on equity was largely the result of an increase in interest rates. As he noted, as of the time of his updated analysis, the level of U.S. Treasury 30-year long-term bond yield forecast is 4.3%, versus 3.7% when he prepared his direct testimony. *Id.* at 130. He noted further that the increase in forecast interest rates increases the CAPM, the empirical approximation to the CAPM (ECAPM), Historical Risk Premium, and Allowed Risk Premium results in his direct testimony. *Id.* at 33, 131. Finally, while his DCF modeling showed a slight decrease, the DCF results did not offset the increase in interest rates. *Id.* Dr. Morin concluded that the "net result of these capital market changes is a small increase in the cost of common equity." *Id.* at 131.

In his direct testimony DEP witness Morin also surveyed the current risk environment, describing a paradigm shift in the electric utility industry's risk profile. He described a "perfect storm" environment, in which "the industry is experiencing declining demand growth, rising operating costs, rising capital costs, while at the same time the industry is beset by lower allowed returns," and noted that as a result "[i]t is not surprising that investor risk perceptions have escalated" in this setting. *Id.* at 89.

Witness Morin attributed this increase in industry risk to four major challenges facing electric utilities: (1) declining growth in energy consumption due to improvements in energy science and productivity; (2) the need for record amounts of capital to replace aging infrastructure, improve reliability, and deliver renewable generation; (3) higher business risks, including the emergence of "prosumers," that is, customers (residential, commercial, industrial) who are both consumers and producers as a result of the increase in distributed generation; and (4) rising operating costs due to rising inflation and supply chain bottlenecks. *Id.* at 91-93. He concluded with the observation that "[g]iven the new paradigm shift in the industry, it is transparent that state regulatory support, including adequate returns on equity, will be instrumental to ensure ongoing capital attraction in the utility sector at reasonable costs." *Id.* at 93.

Finally, witness Morin surveyed economic conditions in North Carolina. He considered key macroeconomic factors such as GDP growth, employment data, and household income levels in North Carolina and DEP's service territory relative to the aggregate U.S. economy. *Id.* at 95. He opined that the economic conditions remain highly correlated with national conditions, such that they were reflected in the analyses used to

determine the cost of equity. *Id.* at 103. He noted that economic conditions in North Carolina continue to improve from the COVID-19 pandemic, and they continue to be strongly correlated to conditions in the broader U.S economy. *Id.* He further noted that unemployment at the state level continues to fall and remains highly correlated with national rates of unemployment, and that GDP growth also remains well correlated with U.S. GDP growth. *Id.* Median household income in North Carolina has grown at a rate consistent with the rest of the U.S. and remains strongly correlated with national levels. *Id.* Witness Morin concluded that, "the correlations between state-wide measures of economic conditions noted by the Commission in Docket No. E-22, Sub 479 remain strongly in place and, as such, they continue to be reflected in the models and data used to estimate the cost of equity capital." *Id.*

Intervenor Testimony (rate of return experts)

The intervenor rate of return on common equity expert witnesses generally criticized DEP witness Morin's analysis that resulted in his recommended 10.4% rate of return on common equity. In addition, they performed their own analyses as outlined below.

Direct Testimony of Public Staff witness Walters

Public Staff witness Walters used nearly the same proxy group of electric utilities relied on by DEP witness Morin, except that he excluded two utilities, FirstEnergy and MGE Energy. Tr. vol. 16, 248. He performed DCF, Risk Premium, and CAPM analyses for his proxy groups of electric utilities. *Id.* at 242. Witness Walters developed his DCF growth rate by relying on a consensus of professional securities analysts' earnings growth estimates, averaging the growth rate forecasts from Yahoo Finance, MI, and Zack's. *Id.* at 252-53. Public Staff witness Walters recommended a rate of return on common equity of 9.45% based on a capital structure of 52% common equity and 48% long-term debt. *Id.* at 247, 284. In the alternative, he recommended a rate of return on common equity of 9.25% if the Commission grants DEP's MYRP and PBR application. *Id.* at 288.

Public Staff witness Walters applied the DCF model, Risk Premium Model, and CAPM that yielded the following results:

Discounted Cash Flow (DCF) – 9.0% Recommended DCF Result

	Mean	Median
Constant Growth – Consensus Analyst	9.01%	9.03%
Constant Growth – Sustainable Growth Rate	8.83%	8.47%
Multi-Stage Growth	7.91%	7.89%

Risk Premium Model – 9.9% Recommended Risk Premium Result

Projected Treasury Yield (3.700%)	9.74%	
	A-rated	Baa-rated
13-week Average Utility Bond Yield	9.93%	10.22%
26-week Average Utility Bond Yield	10.04%	10.34%

Capital Asset Pricing Model (CAPM) – 9.5% Recommended CAPM Result

	Current VL Beta	Historical VL Beta	Current MI Beta
D&P Normalized Method	9.22%	8.46%	8.69%
Risk Premium Method	10.72%	9.72%	10.02%
FERC DCF	9.78%	8.92%	9.18%

Id. at 264, 71, 83-84.

In his DCF analysis, witness Walters used the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on February 10, 2023. *Id.* at 251. For his constant growth model, he used the most recently paid quarterly dividend as reported in ValueLine and an expected growth rate based on a consensus of professional securities analysts' earnings growth estimates as a proxy for investors' dividend growth rate expectations. *Id.* at 251-53. For his sustainable growth model, he estimated the long-term growth rate based on DEP's current market-to-book ratio and on Value Line's three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances. *Id.* at 256. His Multi-Stage growth model relied on inputs from three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 and extending into perpetuity. *Id.* at 258. For the short-term growth period, he relied on the consensus of analysts' growth projections described above in relationship to his constant growth DCF model. For the transition period, he reduced or increased the growth rates by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, he assumed each company's growth would converge to the maximum sustainable long-term growth rate. *Id.* at 259. Lastly, while not his typical practice, he provided DCF models using historical growth inputs, which resulted in DCF estimates ranging from 7.91% to 9.89%. *Id.* at 265.

Witness Walters' risk premium model is based on two estimates of an equity risk premium: the difference between the regulatory commission-authorized returns on common equity and (1) contemporary U.S. Treasury Bonds, and (2) contemporary Moody's "A" rated utility bond yields. He evaluated these premia over the period of 1986-2021 on an overall average and rolling five- and 10-year basis. *Id.* at 266-67. In addition, he evaluated the average spread between Treasury bonds and A- and Baa-rated utility

bonds. *Id.* at 269. Finally, witness Walters added what he deems an appropriate premium in the third quartile of the rolling five-year average risk premia (6.04%) to his projected Treasury bond yields (3.7%), which produces a return on equity of 9.74%. Additionally, witness Walters applies a similar methodology to utility bond yields to estimate an equity risk premium of 4.63%.[12] He adds this to the 13- and 26-week average A- and Baa-rated utility bond yields. *Id*. at 270-71.

Witness Walters' CAPM analysis used the Blue Chip Financial Forecasts' projected 30-year U.S. Treasury bond yield of 3.7% for the risk-free interest rate. *Id.* at 274. He used the Value Line beta estimates of 0.89, the historical average Value Line beta since 2014 of 0.76, and the adjusted beta estimates provided by Market Intelligence's Beta Generator Model of 0.80 for his proxy group. *Id.* at 275. Witness Walters used two versions of the constant growth DCF model to develop his estimates of the market risk premiums. *Id.* at 278. He used the 6.85% average of his estimated market risk premiums of 6.4% and 7.3%. *Id.* at 279. He testified that his 6.85% market risk premium is a reasonable, if not a high-end estimate. *Id.* at 281.

Witness Walters concluded that the appropriate equity cost rate for DEP based on companies in his proxy group is in the 9.0% to 9.9% range, recommending the midpoint of 9.45%. *Id.* at 284. However, witness Walters testified that DEP's PBR application would shift risk from shareholders to ratepayers by reducing regulatory lag. *Id.* at 285. As such, he recommended a 9.25% rate of return on common equity, should the Commission grant DEP's MYRP and PBR application. *Id.* at 288. Witness Walters also testified as to current capital market conditions as of the date of his testimony in April 2020. He stated that the authorized rates of return on common equity for electric utilities have declined over the last several years. *Id.* at 222.

Direct Testimony of CUCA witness O'Donnell

CUCA witness O'Donnell proposed a rate of return on common equity of 9.25% (without regard to DEP's MYRP proposal), based upon DCF modeling and CAPM methodologies, as well as a comparable earnings approach. Tr. vol. 21, 627. Witness O'Donnell primarily relied upon the DCF model and testified that it is superior to the others because it has a direct and immediate link to stock prices. *Id.* at 602-03. Witness O'Donnell's DCF analysis results range from 8.7% to 9.7% with an overall result of 9.25%. *Id.* at 614. His CAPM analysis ranged from 7.25% to 8.25% with a midpoint of 7.75%. *Id.* at 626. His Comparable Earnings Analysis (CEA) ranged from 9.5% to 10.5% with a midpoint of 10.0%. *Id.*

Witness O'Donnell, like Public Staff witness Walters, made a downward adjustment to his rate of return on common equity recommendation in the event the

[12] Witness Walters states in his testimony that he adds 5.33%, but the math in his narrative indicates 4.63% was used, and 4.63% is supported by Exhibit CCW-12.

Commission approves DEP's MYRP. The downward adjustment would take his rate of return on equity recommendation from 9.25% to 9.0%. *Id.* at 627.

Direct Testimony of DoD-FEA Witness Reno

DoD-FEA witness Reno recommended that the Commission approve a rate of return on common equity of 9.3% and reject DEP's requested 10.4%. *Id.* at 349-50. She conducted her analysis by deriving average expected market returns for a proxy group of regulated electricity companies with risk comparable to DEP. *Id.* at 362. Her analysis applied two DCF models, CAPM, and ECAPM, as well as a Comparable Earnings Model. Witness Reno summarized her model results in her Table 7, reproduced below:

Table 7. ROE Estimates (%)

DCF Methodology	30-Day Stock Price	90-Day Stock Price	Average
Constant-Growth DCF (EPS Growth)	9.57	9.54	
Constant-Growth DCF (DPS, EPS and BVPS)	9.19	9.11	
Sustainable Growth DCF	8.42	8.35	
DCF Range:	**8.35**	**9.57**	**8.96**
CAPM & ECAPM Methodology	**CAPM**	**ECAPM**	
Capital Asset Pricing Model (Lg. Stock ERP, 30-yr T-Bond Rate)	10.42	10.63	
Capital Asset Pricing Model (Supply-Side ERM, 30-yr T-Bond Rate)	9.32	9.49	
Capital Asset Pricing Model (D&P Normalized Rate)	8.83	9.00	
CAPM Range:	**8.83**	**10.63**	**9.73**
Comparable Earnings Methodology			
Comparable Earnings Model (Historical ROE)	10.26		
Comparable Earnings Model (Adjusted ROE)	11.10		
Comparable Earnings Model (VL Forecasted ROE 25-27)	11.00		
CEM Range:	**10.26**	**11.10**	**10.68**
Summary			
DCF-Based ROE Average			8.96
DCF-CAPM-Based ROE Average			9.35
All-Model ROE Average			9.79
	Min	**Max**	**Midpoint**
ROE Range	8.96	9.57	9.26
Recommended ROE (%)			**9.30**

Id. at 395.

Witness Reno's recommended rate of return on equity of 9.3% represents the midpoint of her constant-growth DCF outcomes (her primary method) and is supported by the average of her DCF and CAPM methods of 9.35%. The average of all of witness Reno's models is 9.79%. *Id.* at 373.

Direct Testimony of NCJC, et al. witness Ellis

NCJC, et al. witness Ellis recommended a rate of return on common equity of 6.0%, based on the minimum required to maintain DEP's current A2 credit rating. *Id.* at 1071. Witness Ellis criticized DEP witnesses for their conflation of the rate of return on capital and the cost of capital, arguing that such confusion has led to excessive authorized returns. *Id.* at 940-42. He testified that his analysis relies on the premise that rate of return on common equity and capital structure are interrelated and cannot be determined separately. *Id.* at 1055-60.

Witness Ellis' analysis relies on the DCF and CAPM to estimate the cost of capital. *Id.* at 937. His analysis yielded the following results:

Multi-Stage Discounted Cash Flow: 6.25%

Capital Asset Pricing Model: 5.8%

Id. at 939.

He opined that the multi-stage DCF model should be used instead of the constant growth DCF model because it allows for more realistic cash flow projects, yielding more accurate results. *Id.* at 990. He testified that his CAPM analysis eliminates the upward biases seen in Witness Morin's CAPM analysis. *Id.* at 997.

Witness Ellis testified that rate of return on common equity and capital structure are interrelated and must be addressed together. *Id.* at 1056-57. He recommended along with his 6.0% rate of return on common equity that the Commission set DEP's capital structure at 58.0% equity and 42.0% debt and indicated that this combination would maintain DEP's credit rating. *Id.* at 1071.

Intervenor Testimony (other experts)

As noted above, both Commercial Group witness Chriss and CIGFUR witness Gorman provided rate of return on common equity-related testimony but did not perform any ROE analysis.

Direct Testimony of Commercial Group witness Chriss

While he did not provide a rate of return on common equity analysis in his testimony, witness Chriss for the Commercial Group testified that DEP's proposed rate of return on common equity was significantly higher than rates of return previously approved

by the Commission from 2019 to the present. *Id.* at 513-14. Likewise, witness Chriss indicated that DEP's proposed ROE is significantly higher than most reported rate of return on common equity decisions by utilities commissions from 2019 to the present. *Id.* at 515-17. He testified that according to S&P Global Market Intelligence, 141 decisions were rendered during that time frame, with results ranging from 7.36% to 10.6%, with the median authorized ROE at 9.5%. *Id.* at 515. Removing distribution-only utilities and distribution service rates from the analysis, he testified that the average rate of return on common equity for vertically integrated utilities authorized from 2019 through the time of his direct testimony filing was 9.61%. *Id.*

Direct Testimony of CIGFUR witness Gorman

CIGFUR witness Gorman proposed that the Commission adjust DEP's authorized return on equity to reflect the current industry average of 9.6%. *Id.* at 405. He testified that for vertically integrated utilities, the authorized rate of return on common equity was around 9.53% in 2021, 9.69% in 2022, and currently holds around 9.6% for 2023. *Id.* at 409. He testified further that a fair ROE and a lower-cost, more balanced ratemaking capital structure would lower DEP's cost of service and support the implementation of more competitive rates. *Id.* at 411. He further testified that the proposed 10.4% ROE significantly exceeds the authorized returns on equity for other regulated utilities companies, which have been sufficient to maintain credit and provide utilities access to capital under reasonable terms and prices. *Id.* at 450-51.

DEP Rebuttal Testimony

In his rebuttal testimony, DEP witness Morin responded to criticism by intervenor ROE witnesses and commented upon deficiencies in their analyses. While he testified that he agrees with several of the views and procedures presented by witness Walters and witness O'Donnell, he noted that their recommendations understate the appropriate ROE for DEP. Tr. vol. 8, 139, 171. Particularly, he reasoned that their recommendations lie outside of the zone of currently authorized rates of return on common equity for vertically integrated electric utilities in the United States, which have averaged 9.7% in the past and have trended upward in more recent decisions in response to the surge in interest rates and inflation. *Id.* at 139, 169. He further noted that neither witness Walters, nor witness O'Donnell, nor witness Reno explained why or how DEP's cost of equity capital has decreased since it was awarded a rate of return on common equity of 9.6% in its last rate case in 2021, given a surge in interest rates and inflation that each of them acknowledged in their testimony. *Id.* at 223.

Witness Morin further disputed the contentions of witnesses Walters, O'Donnell, and Reno that the adoption of a performance-based ratemaking statute in North Carolina, including multi-year rate plans, should result in a lower rate of return on common equity for DEP. *Id.* at 135. He noted that the peer group of electric utilities also includes other risk-mitigating mechanisms, taken account in the use of the proxy group's financial data. *Id.* As such, further adjustment on the basis that an MYRP reduces risk amounts to double counting and should be rejected. *Id.*

Witness Morin additionally challenged the findings of the intervenors individually. While he noted that they shared quite a bit of common ground in their analyses, witness Morin testified that Public Staff witness Walters' recommended rate of return on common equity lies outside of the zone of currently authorized rates of return on common equity for vertically integrated utilities and opined that if his results were amended to reflect proper data inputs to the financial models, his results would exceed 10.0%. *Id.* at 139-67. He offered the following seven points of disagreement. *Id.* at 140.

Witness Morin criticized witness Walters' reluctance to accept flotation costs, explaining that the parent-subsidiary relationship does not eliminate the cost of stock issuance. *Id.* at 142. He disagreed with witness Walters' DCF technique, explaining that his sustainable growth rate approach was illogical and inconsistent with empirical evidence. *Id.* at 143-46. He testified that witness Walters' multi-stage DCF should not be given any weight by the Commission, as it is predicated on the idea that utilities grow at the same rate as the general macro-economy. *Id.* at 148. He wholly rejected witness Walters' use of the historical Value Line beta estimates and Vasicek-adjusted betas, explaining that their use is not standard and the extent to which market participants rely on them is unclear. *Id.* at 153-54. He argued that witness Walters' CAPM underestimates the appropriate cost of capital. *Id.* at 159-60. In challenging witness Walters' risk premium analysis, witness Morin testified that it fails to recognize the inverse relationship between risk premium and interest rates. *Id.* at 160-61. Finally, witness Morin disagreed with witness Walters' criticisms of his testimony, noting that nothing presented would cause him to alter any of his recommendations or methodologies. *Id.* at 167.

At the outset, witness Morin identified two fundamental flaws in CUCA witness O'Donnell's testimony, noting that his proposed 9.25% rate of return on common equity would be one of the lowest in the industry and that it is the result of a defective DCF analysis. *Id.* at 168-71. While witness Morin agreed with parts of witness O'Donnell's analysis, he identified six specific areas of disagreement over the appropriate data inputs for the CAPM and DCF models. *Id.* at 172. He explained that witness O'Donnell's recommended rate of return on common equity is outside the zone of currently authorized rate of return on common equity for vertically integrated electric utilities in the United States and that of his own sample of companies, noting that the currently authorized returns for his peer companies average nearly 10.0%, and the expected returns for these companies from his own Value Line data shown on Exhibit KWO-4 are in the range of 10.6% – 11.1%. *Id.* at 172-73. He asserted that two of witness O'Donnell's dividend yield estimates are understated because they are based on stock prices reaching back several months in the past, thus violating the notion of market efficiency. *Id.* at 173. Witness Morin raised concern with witness O'Donnell's choice of DCF growth rates, finding his reliance on 12 different rates, including historical growth rates, sustainable growth rates, and analysts' forecasts arbitrary and inconsistent with empirical evidence. *Id.* He further questioned witness O'Donnell's reliance on historical growth rates in his DCF model, explaining that the substantial changes occurring in the electric utility industry make use of those rates questionable. *Id.* at 174.

While he agreed with parts of witness O'Donnell's CAPM analysis, witness Morin argued that witness O'Donnell's risk-free rate assumption is too low. *Id.* at 182. Witness Morin also testified that witness O'Donnell's denunciation of analysts' growth forecasts as unreasonable proxies for the DCF growth rate is without foundation and inconsistent with empirical finance literature on the subject. *Id.* at 192.

Witness Morin challenged DoD-FEA witness Reno's analysis, particularly her exclusive reliance on her Constant Growth DCF. *Id.* at 196. He reiterated his concerns about using the sustainable growth methodology due to its inherent circularity and encourages the rejection of the 90-day stock price DCF in violation of the Efficient Market Hypothesis, leaving only two DCF results from her analysis to consider. *Id.* at 198. He agreed with witness Reno's decision to give little weight to the Kroll 6.0% normalized market risk premium (MRP), as well as her comparable earnings analysis results. *Id.* at 198-99. Finally, he disputed witness Reno's criticisms of his own analyses, noting that her risk premium analysis uses a group with a nearly identical beta risk estimate and that her opposition of a flotation allowance disregards the fact that the parent-subsidiary relationship does not eliminate the costs of a new issue of stock. *Id.* at 199-200.

Witness Morin highlighted the limited analysis performed by Commercial Group witness Criss and CIGFUR witness Gorman. *Id.* at 201. He testified that witnesses Criss and Gorman determined their recommendations merely by averaging what other regulators have allowed in 2022. *Id.* He criticized the circular nature of their recommendations and noted the large deviations among the utilities included in their proposed averages. *Id.* at 202. He encouraged the Commission to disregard their testimonies as not germane and to exercise a mind of its own rather than relying on the actions of other Commissions. *Id.* at 203.

Witness Morin wholly rejected the testimony of NCJC, et al. witness Ellis, describing his approach as "non-mainstream, far-fetched, and unorthodox for both methods he uses to estimate the cost of capital." *Id.* at 204. He described witness Ellis' recommendation as draconian and described the adverse consequences to DEP's creditworthiness, financial integrity, capital raising ability, and its customers, should the Commission adopt it. *Id.* He also identified witness Ellis' inconsistencies and contradictions, such as his challenging the validity of the same consensus economic forecasts he relies on to make his recommendations. *Id.* at 205. Witness Morin challenged witness Ellis' differentiation of cost of capital and rate of return and dismissed his position on the use of Market-to-Book ratios in utility regulation. *Id.* at 206-07. In addition to challenges to witness Ellis's recommendations, witness Morin offered a myriad of criticisms to the application of his methodologies. He explained that witness Ellis' misuse of geometric averages rather than arithmetic averages produces results clearly contrary to the most basic financial theory. *Id.* at 210-12. He further identified multiple other instances where witness Ellis' methods deviate from academic state of the art practices, including his rejection of the constant growth DCF analysis and his condemnation of Value Line beta estimates. *Id.* at 205, 214, 219.

Law Governing the Commission's Decision on Rate of Return on Equity

Rate of return on equity is often one of the most contentious issues to be addressed in a rate case. The baseline for establishment of an appropriate rate of return on common equity is the constitutional constraints established by the decisions of the United States Supreme Court in *Bluefield Water Works & Improvement Co. v. Public Service Commission*, 262 U.S. 679 (1923) (Bluefield), and *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) (*Hope*), which establish:

> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting [an ROE], the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital.

Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, *Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 1146 , at 50 (June 22, 2018); *see also State ex rel. Utils. Comm'n v. Gen. Tel. Co.,* 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972) (General Telephone). As the North Carolina Supreme Court held in *General Telephone*, these factors constitute "the test of a fair rate of return declared" in *Bluefield and Hope*. *Id.*

The rate of return on equity is, in fact, a cost – the return that equity investors require represents the cost to the utility of equity capital. In his dissenting opinion in *Missouri ex rel. Southwestern Bell Telephone Co. v. Missouri Public Service Commission*, 262 U.S. 276 (1923), Justice Brandeis remarked upon the lack of any functional distinction between the rate of return on equity (which he referred to as a "capital charge") and other items ordinarily viewed as business costs, including operating expenses, depreciation, and taxes:

> Each is a part of the current cost of supplying the service; and each should be met from current income. When the capital charges are for interest on the floating debt paid at the current rate, this is readily seen. But it is no less true of a legal obligation to pay interest on long-term bonds . . . and it is true also of the economic obligation to pay dividends on stock, preferred or common.

Id. at 306 (Brandeis, J., dissenting). Similarly, the United States Supreme Court observed in *Hope*, "[f]rom the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business . . . [which] include service on the debt and dividends on the stock." 320 U.S. at 591, 603.

The North Carolina Supreme Court has long recognized that the Commission's subjective judgment is a necessary part of determining the authorized rate of return on common equity. *See, e.g., State ex rel. Utils Comm'n v. Public Staff-N.C. Util's. Comm'n*, 323 N.C. 481, 490, 374 S.E.2d 361, 369 (1988) (*Public Staff*). Likewise, the Commission has noted that such determination is not made by application of any one simple mathematical formula:

> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
>
> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
>
> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:
>
> > There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
> >
> > As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.
>
> Charles F. Phillips, Jr., The Regulation of Public Utilities, 3d ed. 1993, pp. 382 (notes omitted).

Order Granting General Rate Increase, *Application of Carolina Power & Light Co., d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1023, at 35-36 (May 30, 2013), *aff'd, State ex rel. Utils. Comm'n v. Cooper*, 367 N.C. 444, 761 S.E.2d 640 (2014) (2013 DEP Rate Order).

Moreover, in setting rates the Commission must not only adhere to both the United States and North Carolina Constitutions, but as held by the North Carolina Supreme Court, it must set rates as low as possible consistent with constitutional law. *Public Staff*, 323 N.C. at 490, 374 S.E.2d at 370. Further, the North Carolina General Assembly has provided that the Commission must also set rates employing a multi-element formula set forth in N.C.G.S. § 62-133. The formula requires consideration of elements beyond just the rate of return on common equity element, and it inherently necessitates that the Commission make many subjective determinations, in addition to the subjectivity required to determine the rate of return on common equity. The subjective decisions the Commission must make as to each of the elements of the formula can and often do have multiple and varied impacts on all of the other elements of the formula. In other words, the formula elements are intertwined and often interdependent in their impact to the setting of just and reasonable rates.

The fixing of a rate of return on the cost of property used and useful to the provision of service (as determined through the end of the historic 12-month test period prior to the proposed effective date of a requested change in rates and adjusted for proven changes occurring up to the close of the expert witness hearing or projected in accordance with the provisions of N.C.G.S. § 62-133.16(c)(1)(a)) is one of several interdependent elements of the statutory formula to be used in setting just and reasonable rates. North Carolina General Statute § 62-133(b)(4) provides, in pertinent part, that the Commission shall:

> [f]ix such rate of return on the cost of the property . . . as will enable the public utility by sound management [1] to produce a fair return for its shareholders, *considering changing economic conditions and other factors* . . . [2] to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and [3] to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors. [Emphasis added.]

N.C.G.S. § 62-133(b)(4).

The North Carolina Supreme Court has interpreted the above-emphasized language as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper rate of return on common equity for a public utility. *Cooper I*, 366 N.C. at 495, 739 S.E.2d at 548. The Commission must exercise its subjective judgment so as to balance two competing rate of return on common equity-related factors – the economic conditions facing DEP's

customers and DEP's need to attract equity financing on reasonable terms in order to continue providing safe and reliable service. 2013 DEP Rate Order at 35-36. The Commission's determination in setting rates pursuant to N.C.G.S. § 62-133, which includes the fixing of the rate of return on common equity, always takes into account affordability of public utility service to the using and consuming public. The impact of changing economic conditions on customers is embedded in the analyses conducted by the expert witnesses on rate of return on common equity, as the various economic models widely used and accepted in utility regulatory rate-setting proceedings take into account such economic conditions. 2013 DEP Rate Order at 38. Further,

> [t]he Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on common equity when the general body of ratepayers is in a better position to pay than at other times . . . .

Id. at 37.

Economic conditions existing during the modified test year, at the time of the public hearings, and at the date of the issuance of the Commission's order setting rates will affect not only the ability of the utility's customers to pay rates but also the ability of the utility to earn the authorized rate of return during the period the new rates will be in effect. However, in setting the rate of return on common equity, just as the Commission must assess the impact of economic conditions on customers' ability to pay for service, it likewise must assess the effect of regulatory lag on DEP's ability to access capital on reasonable terms. The Commission sets the rate of return on common equity considering both of these impacts taken together in its ultimate decision fixing a utility's rates.

Thus, in summary and in accordance with the applicable law, the Commission's duty under N.C.G.S. § 62-133, as well as N.C.G.S. § 62-133.16, is to set rates as low as reasonably possible to the benefit of the customers without impairing DEP's ability to attract the capital needed, at reasonable rates, in order to provide safe and reliable electric service and recover its cost of providing service.

Discussion and Conclusions

Two basic issues relating to ROE are presented in this case. First, the Commission must, based upon the evidence presented, select the appropriate ROE for DEP. Second, the Commission must determine whether a downward adjustment to that ROE is appropriate in light of North Carolina's adoption of PBR, in particular, the potential for an MYRP, and the Commission's approval of DEP's PBR Application, as modified by this Order. For the reasons set forth herein, the Commission determines that: (1) the appropriate ROE to be awarded to DEP in this case is 9.8%, and (2) downward adjustment to otherwise applicable ROE is not warranted in view of (a) the widespread

acceptance of alternative regulation throughout the United States, and (b) a comparison of North Carolina's alternative regulation program as promulgated by the PBR Statute and other states' alternative regulation. The Commission is persuaded that that comparison shows, as DEP witness Bateman testified, that North Carolina is not "less risky, in terms of regulatory framework, than other states on average across the country." Tr. vol. 15, 96.

Setting the Rate of Return on Common Equity

As is the norm, the expert witnesses for DEP, the Public Staff, and other intervenors differ widely in their ROE recommendations.[13] A summary of the model outputs of the various witnesses illustrates this divergence (bold indicates a point estimate, while parenthetical figures below are the range of model outcomes provided by the witness):

	DCF (Constant Growth*)	CAPM	Risk Premium	Comparable Earnings	Overall
Morin (DEP Supp.)	9.3%	11.0%-11.2%	10.5%-10.8%	Not Performed	10.4%
Morin (DEP, Direct)	9.3%-9.9%	10.8%-11.1%	10.2%	Not Performed	10.2%
Walters (The Public Staff)	**9.0%** (8.47%-9.03%)	**9.5%** (8.46-10.72%)	**9.9%** (9.74-10.34%)	Not Performed	9.45%
O'Donnell (CUCA)	**9.25%** (8.7-9.7%)	7.25%-8.25%	Not Performed	Not relied upon 9.5%-10.5%	9.25%
Reno (DoD-FEA)	**9.3%** (9.11%-9.57%)	8.83%-10.63%	Not Performed	10.26%-11.1%	9.3%
Ellis (NCJC, et. al.)	6.25%	5.8%	Not Performed	Not Performed	6.0%
Gorman (CIGFUR)					9.6%

[13] The Commission places little weight on the rate of return on equity testimony of Commercial Group witness Chriss and CIGFUR witness Gorman as neither actually performed any rate of return on equity analysis, beyond looking to average authorized rate of return on equity awards by utility commissions, including this Commission. While looking to such industry average data can be beneficial, it does not substitute for the rigorous analysis the law and the Commission demand in setting the allowed rate of return on equity.

*Although Public Staff witness Walters and DoD-FEA witness Reno performed multi-stage and sustainable growth DCF models, they did not rely on their outputs. As such, the figures above exclude those results. NCJC, et. al. witness Ellis's 6.25% is the result of a multi-stage growth DCF analysis.

As is also typical of rate of return on equity testimony, the various expert witnesses rely on many of the same models to inform their cost of equity estimates. However, the results of these models vary due to differences of opinion on the appropriate inputs. In the following pages, the Commission will weigh and consider the inputs in order to narrow the range of reasonable outcomes. Further, while DoD-FEA witness Reno and CUCA witness O'Donnell primarily rely upon their DCF results, it has been the Commission's long-standing practice to consider and place weight on multiple models in order to protect against any one model's skewing the outcome in times when it may be less indicative of the true cost of capital. The Commission also notes that DEP witness Morin's figures above, with the exception of his Allowed Risk Premium measure, include a flotation cost adjustment of approximately 0.2%. Tr. vol. 8, 53-54, 73, 75, 78.

The Commission, for reasons discussed below, concludes that a flotation cost adjustment is not warranted in this case. As such, the following discussion excludes them from consideration in setting the allowed return on equity.

Discounted Cash Flow Model

Despite the wide range of overall recommendations provided by the expert witnesses, with the exception of NCJC, et al. witness Ellis's 6.25% result, the recommended results of the DCF models form a relatively tight band from 9.0% to 9.3%. While the remaining witnesses disagreed on the appropriate growth adjustment to apply to the dividend yield, a 30-basis point window of outcomes reflects consensus regarding an appropriate model output for the DCF model. This remains the case even after removing DEP witness Morin's 20 basis point flotation cost adjustment.

The Commission concludes that NCJC, et al witness Ellis's outcome of 6.25% is an outlier and should be ignored. Apart from being more than 300 basis points below any rate of return on equity ever approved by this Commission for DEP, it is scarcely 200 basis points above DEP's embedded cost of debt, a premium that is clearly insufficient to compensate investors for the added risks associated with equity ownership relative to a debtholder's claim on the same enterprise. Further, NCJC, et al witness Ellis is alone in his reliance on a DCF method other than the constant growth DCF model. In contrast, DoD-FEA witness Reno and Public Staff witness Walters both conducted a multi-stage DCF model, and subsequently ignored or discounted those results. Tr. vol. 16, 264; Tr. vol. 21, 395.

As a result of their relatively narrow band of 9.0% to 9.3%, the Commission concludes that the DCF analyses of DEP witness Morin, CUCA witness O'Donnell, Public Staff witness Walters, and DoD-FEA witness Reno, are credible, probative, and entitled to substantial weight.

Risk Free Rate

A key input to both the risk premium and CAPM models is the risk free rate. On cross examination, DEP witness Morin testified that, due to a decline in interest rates between the time of filing of his supplemental testimony and the hearing, his recommended rate of return on equity would have been 0.2% lower if recalculated. *Id.* at 323-324. The Commission appreciates DEP witness Morin's candor in this regard and understands that, due to the dynamic nature of financial markets, model outcomes calculated on any given day would reflect the inputs available on that day, and as such would change from day to day. With or without this correction, however, DEP witness Morin's preferred measure of the risk free rate that he used in his supplemental testimony, 4.3%, based on projections, diverges meaningfully from the actual 30-year Treasury rate both at the time of filing and during the hearing. DoD-FEA witness Reno reports the 30-day average yield on the 30-year Treasury bond was 3.79% as of February 28, 2023. Tr. vol. 21, 382. NCJC, et al. witness Ellis uses the January average of 3.66%. Tr. vol. 21, 939. DEP witness Morin himself reports the yield to be between 3.9% and 4.0% as of the date of the hearing. Tr. vol. 8, 324. CUCA witness O'Donnell uses the range of yields over the prior 12 months of 2.42% to 4.4%, and Public Staff witness Walters uses his own projected value of 3.7%. Tr. vol. 16, 274; Tr. vol. 21, 625.

In support of his use of projected interest rates, DEP witness Morin testified that,

> Cost of capital models, including both the CAPM and DCF models, are prospective (i.e., forward-looking) in nature and must take into account current market expectations for the future because investors price securities on the basis of long-term expectations, including interest rates. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflects the expectations of actual investors in the market.

Tr. vol. 8, 60.

The Commission considers the single best indicator of "the expectations of actual investors in the market" to be the yield they are willing to accept on the bonds they own. Where this information is available, either in the form of current yields or forward yields based upon the same, the Commission will continue to prefer using these rates to projections offered by market commentators.

DEP Witness Morin's direct testimony relied upon a risk free rate of 3.7%, and in response to a question from Chair Mitchell, he confirms that had he relied on the same 3.7% rate in his supplemental testimony, the outputs would have largely been in-line with the model outputs from his direct testimony (i.e. 20 basis points lower than his supplemental testimony). As a result, the Commission will place somewhat more emphasis on DEP witness Morin's direct testimony than his supplemental testimony with regard to his CAPM and Risk Premium Model outcomes.

Capital Asset Pricing Model (CAPM)

The wide range of results for the CAPM from the various intervenors shed light on the importance of the underlying inputs to the model. Of primary importance are the assumed risk free rate, market risk premium and beta, as the model's output is the sum of the former and the product of the latter two. As discussed above, a risk free rate in the range of 3.7% to 3.9% reasonably aligns with prevailing 30-year Treasury yields at the time of the hearing, and with the exception of CUCA witness O'Donnell, the expert witnesses have each provided models utilizing this input. CUCA witness O'Donnell, for his part, utilized a range of yields that cover the considerable variability of the measure over the 12 months prior to his testimony (2.42% to 4.4%). Tr. vol. 21, 625. While not exactly a match, it would indicate that top half of his indicated range overlaps with the others on the basis of risk free rate.

Turning next to beta, the witnesses diverge considerably. DEP witness Morin was adamant that a beta of 0.89, reflecting the current Value Line average for the proxy group. Public Staff witness Walters also employed this figure, along with average betas going back to 2014 (0.76) and betas from Market Intelligence's Beta Generator. The Commission agrees with DEP witness Morin that using stale betas is incorrect and prefers the current Value Line average, as they better reflect current market fundamentals. The Commission also accepts DEP witness Morin's rationale for rejecting the Vasicek adjusted betas from Market Intelligence. CUCA witness O'Donnell appeared to agree with DEP witness Morin, and used a 0.88 beta for the proxy group, sourced from Value Line. Tr. vol. 21, 625. Similarly, DoD-FEA witness Reno relied upon a Value Line beta of 0.89. *Id.* at 384. NCJC, et al. witness Ellis rejected the Value Line beta because Value Line considers five years of trailing data, meaning it continues to reflect the effects of pandemic-related market turmoil and asserted that they do not reflect current investor risk perceptions. *Id.* at 1010. Instead he offers several alternatives, including from providers that allow users to modify beta calculation parameters. *Id.* at 1012. On rebuttal, DEP witness Morin testified that Value Line betas are widely used and well-known to investors, that Diana Harrington's work established them as consistently the best at predicting ensuing betas, and that NCJC, et al. witness Ellis's preferred alternatives are inferior. Tr. vol. 8, 213-14. The Commission accepts DEP witness Morin's rebuttal of NCJC, et al. witness Ellis on this point and finds reassuring the reliance of other intervening witnesses on Value Line betas in its determination of the appropriate beta.

The MRP, the last variable in the CAPM model, reveals a wider range of assumptions made by the intervening witnesses. DEP witness Morin used 8% in his initial testimony (composed of a historical MRP of 7.4% and a prospective MRP of 8.5%, averaged), and 7.3% in his supplemental testimony, each reflecting an expected market return of 12%. DEP witness Morin opined that an MRP in the range of 6.0% to 8.0% is a reasonable estimate of the cost of equity for CAPM and that the historical MRP approach is simple and difficult to improve upon. Tr. vol. 8, 71. Witness Walters utilized both a historical approach and DCF approach to estimate the MRP, yielding results of 7.9% and 6.85% respectively, and implying expected market returns of 11.6% and 10.52%. Witness Walters also utilized a method from Kroll that provides a normalized risk-free rate of 3.89% and an MRP of 6.0%. Tr. vol. 16, 278-

82. DEP witness Morin accepted witness Walters' first two estimates, but rejected the Kroll based estimate for several reasons, namely that Kroll is a highly selective source, that it lacks transparency, and falls at the bottom of a range indicated by Kroll's own analysis to be a reasonable estimate of the MRP. Tr. vol. 8, 156. Witness Reno used estimates from Kroll of 7.46% (historic arithmetic average) and 6.22% (Ibbotson-Chen supply side model). She also used a 6.0% Kroll recommended U.S. ERP paired with a normalized risk-free rate of 3.5%. Tr. vol 21, 382-83. Witnesses O'Donnell (3.5% to 4.5%) and Ellis (3.98%) offered substantially lower MRP estimates. Tr. vol. 21 939, Exhibit KWO-5; Tr. vol. 21. Witness Morin noted that these estimates are below several widely used estimates of the MRP for U.S. Stocks, that witness O'Donnell did not rely upon the CAPM, and that NCJC, et. al. witness Ellis incorrectly used geometric means in generating his MRP. Tr. vol. 8, 181-83, 210. The Commission agrees that the MRP rates of witnesses Ellis and O'Donnell are unreasonably low and should be ignored.

Witnesses Morin, Reno and Walters all seemed to agree that an estimate for the MRP within a range of 6.0% to 8.0% is reasonable. The Commission agrees.

In light of the foregoing, the Commission finds that a CAPM with inputs in the range of 3.7% to 3.9% for the risk free rate, a beta 0.89, and an MRP of 6.0% to 8.0% is a reasonable outcome. Witness Morin's use of an 8% MRP and 3.7% risk free rate from original testimony, when combined with the updated beta of 0.89 results in a CAPM rate (without flotation costs) of 10.82%. Witness Walters provided three estimates utilizing the current Value Line beta (9.22%, 9.78% and 10.72%), averaging 9.91%, while witness Reno's estimates using Value Line beta (but excluding the estimate which used a normalized risk free rate of 3.5%) were 9.32% and 10.42%, averaging 9.89%. Averaging the 9.9% results from the intervenors, with witness Morin's 10.82% modified result yields an estimated cost of equity of 10.35%. Thus, the Commission concludes that an estimate of 10.35% is a reasonable outcome for the CAPM model.

Empirical CAPM (ECAPM)

In this case, both DEP witness Morin and DoD-FEA witness Reno supported inclusion of an ECAPM result. The ECAPM, according to witness Morin, corrects for the fact that the CAPM under-predicts observed returns when beta is less than one. Public Staff witness Walters took issue with witness Morin's use of an adjusted beta as published by Value Line because the adjustments made in his ECAPM model are mathematically the same as adjusting beta. Tr. vol. 16, 306-07. In rebuttal, witness Morin testified that adjusted betas and ECAPM correct different problems, and that as a result, both are needed. NCJC, et. al. witness Ellis opposed the ECAPM on the grounds that it is not used elsewhere in finance and is not supported by updated research. Tr. vol. 21, 1038. Witness Morin contended the ECAPM is discussed in most finance textbooks, including one cited by witness Ellis. Tr. vol. 8, 217.

The Commission agrees with witness Walters's contention that mathematically, the Blume adjusted betas provided by Value Line achieve the same end. However, it finds witness Reno's support for using these same betas in the ECAPM persuasive and is

further persuaded by witness Morin's testimony that both adjustments are needed because they correct for different things.

As witness Reno and witness Morin's ECAPM calculations were both approximately 20 basis points higher than their CAPM calculations, reflecting the Commission's CAPM conclusions above, the Commission accepts an ECAPM estimate of the rate of return on equity of 10.55% as reasonable.

Together with the results of the CAPM, a combined CAPM range of 10.35% to 10.55% will be used to calculate the required rate of return on equity in this case.

Risk Premium Model

The last major method relied upon by the cost of equity expert witnesses are the Risk Premium methods. DEP witness Morin utilized two variations of this approach. The first compares actual returns of the S&P Utility Index with contemporaneous Treasury returns and applies the 4.3% risk free rate. As with his other methods, he also applied a flotation cost adjustment. His second RPM represents the historical premium of allowed ROEs to the risk free rate. This method does not employ a flotation cost adjustment, as it assumes allowed ROEs factor that in. While the Commission has previously relied upon such models, and finds them credible, as mentioned above, the Commission finds that a risk free rate of 4.3% is overstated, and will instead rely upon witness Morin's Risk Premium Models as provided in his direct testimony, which used 3.7% risk free rate. Those results, after removing the adjustment for flotation costs, averaged 10.1%. The Commission finds this result credible, probative, and entitled to substantial weight.

Public Staff witness Walters also provided a risk premium method based on authorized returns for electric utilities. Witness Walters compares 37 years of authorized returns for electric utilities against contemporaneous bond yields and uses this method to estimate a return on equity of 9.9%. The Commission has given substantial weight to this method in the past and does so in this case as well. Taken together with the 10.1% RPM result of witness Morin, the Commission finds there is credible and probative evidence supporting an RPM-based cost of equity ranging from 9.9% to 10.1%.

Comparable Earnings Method

Although no witness relied upon a comparable earnings method in formulating their recommended rate of return on equity, CUCA witness O'Donnell and DoD-FEA Reno calculated results of 9.5% to 10.5% and 10.26% to 11.1% respectively. The Commission finds these results generally support its decision regarding rate of return on equity in this case.

Indicated Range Prior to Adjustments

In light of the foregoing, the Commission has identified a zone of reasonableness of 9.75% to 10%, reflecting the average of the ranges identified above. The Commission will next examine the proposed adjustments offered by the witnesses.

Flotation Cost Adjustment

Flotation costs are the expenses of issuing equity, such as printing fees, underwriter fees, attorney fees, and other similar fees. Tr. vol. 8, 337. DEP, itself, does not issue equity; instead, equity issuances are made by its publicly traded parent, Duke Energy.

Duke Energy issued no equity during the test year. Duke Energy forecasts there will be no common equity issued from 2023 through 2027. Public Staff Cross Examination Morin – Direct and Rebuttal, Ex. 10. Tr. Ex. vol. 9. DEP witness Newlin testified that "we've said publicly that the holding company is not planning to issue common stock until 2027 at the earliest." Tr. vol. 9, 111.

Flotation costs may not be recovered under these circumstances for the following two separate and independent reasons. First, it would be "unjustified" to cause customers to overpay DEP approximately $48 million dollars towards flotation costs when, in fact, no equity was or will be issued from 2021 through 2027. See, Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Approving Water and Sewer Investment Plan, Granting Partial Rate Increases, and Requiring Customer Notice, *Application by Aqua North Carolina, Inc. for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina and for Approval of a Water and Sewer Investment Plan*, No. W-218, Sub 573, at 62 (June 5, 2023) (2022 Aqua Rate Case).

Second, the recovery of flotation costs is not allowed under North Carolina law where there is no evidentiary support. 2022 Aqua Rate Case at 61-62. The North Carolina Supreme Court in *State ex rel. Utilities Commission v. Public Staff,* 322 N.C. 689, 370 S.E.2d 567 (1988), reversed and remanded the ROE portion of the Commission's Order dated October 31, 1986, Docket No. E-7, Sub 408 for Duke Power Company. The Supreme Court directed the Commission on remand to reconsider the proper rate of return on Duke Power's common equity and also support its conclusion on flotation costs with specific findings. There was no evidence in that case that Duke Power intended to issue new stock for the next three or four years. On remand, the Commission issued its second E-7, Sub 408 Order, reassessed the evidence, and issued new findings of fact and conclusions. The Commission concluded that 13.2% was a fair rate of return on Duke Power's equity and there was a 0.1% increment in the approved 13.2% ROE to cover future stock issuance costs. On the second appeal, the Supreme Court held that the Commission's inclusion of the "stock" issuance increment is not supported by substantial evidence in view of the whole record. *State ex rel. Utils. Comm'n. v. Public Staff*, 331 N.C. 215, 218 (1992). The Supreme Court concluded the Commission's inclusion of a 0.1% ROE increment for purported future financing costs in the approved ROE was not based upon substantial evidence in view of the whole record. The Supreme Court stated:

> As we noted on the first appeal, an 0.1% upward increment in Duke's rate of return on common equity costs ratepayers $ 4.2 million annually in additional rates. Historically, Duke's average costs per issuance of stack

> was $ 3.2 million. In light of the whole record on this issue, particularly in the absence of any evidence that Duke intended to issue stock in the immediate future, there is simply no substantial evidentiary support for the Commission's addition of a 0.1% increment to Duke's rate of return on common equity to cover future stock issuance costs.

State ex rel. Utils. Comm;'n v. Public Staff, 331 N.C. 215 at 221-22.

The Supreme Court further stated and ruled:

> On the first appeal of this case, we questioned whether the record supported *any* adjustment whatever in the rate of return for purported future stock issuance, or financing, costs. We said:
>
> > Since *no* evidence was introduced that Duke intends to issue new stock for the next three or four years, and because there was no evidence regarding the probable cost of a prospective issuance, we question whether the record supports *any* financing cost adjustment. *State ex. rel. Utilities Commission v. Public Staff*, 322 N.C. at 700, 370 S.E.2d at 574 (emphasis added). We are not satisfied, for the reasons alluded to in our first opinion, that the record supports no such adjustment in the common equity rate of return.

Id. at 221.

As in that case, there was and is no plan to issue equity in the present case. Accordingly, there is no evidence to support DEP's request to increase its ROE by 20 basis points for flotation costs. Therefore, the Commission rejects DEP's inclusion of 20 basis points in its ROE request to cover flotation costs.

Downward Adjustment Due to MYRP

N.C.G.S. § 62-133.16(c)(1)(a) requires the Commission to consider any increased or decreased risk to either the electric public utility or its ratepayers that may result from having an approved MYRP.

Public Staff witness Walters and CUCA witness O'Donnell both made specific mathematical downward adjustments in their ROE recommendations to account for what they perceive as the less risky environment DEP now operates in as a result of the passage of the PBR Statute. Witness Walters's downward adjustment was 20 basis points, taking his ROE recommendation from 9.45% to 9.25%. Tr. vol. 16, 288. Witness O'Donnell's downward adjustment was 25 basis points, taking his ROE recommendation

from 9.25% to 9.0%[14]. Tr. vol. 21, 627. Inasmuch as the Public Staff's recommendation is more fully explained in witness Walters's testimony, the Commission will address it, but the same factors described in this discussion apply with equal force to the recommendations of witnesses O'Donnell and Reno.

While asserting that there were other reasons to support a downward adjustment, witness Walters conceded that "the only stated adjustment for [DEP's] ROE is based on the MYRP." Tr. vol. 16, 336. Further, the actual quantification of the recommended downward adjustment was not performed by witness Walters at all. Instead, he simply adopted the Public Staff's methodology applied in the recent water utility cases, the 2022 Aqua Rate Case., and the general rate case proceeding for Carolina Water Service North Carolina in Docket No. W-354, Sub 400 (the 2022 CWSNC Rate Case). See Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, Approving Water and Sewer Investment Plan, and Requiring Customer Notice, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates and Charges for Water and Sewer Utility Service in All Service Areas of North Carolina and Approval of a Three-Year Water and Sewer Investment Plan*, No. W-354, Sub 400 (Apr. 26, 2023); *See also* Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Approving Water and Sewer Investment Plan, Granting Partial Rate Increases, and Requiring Customer Notice, *Application by Aqua North Carolina, Inc., for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina and for Approval of a Water and Sewer Investment Plan*, No. W-218, Sub 573 (June 6, 2023). In footnote 29 of his direct testimony, witness Walters linked to the Public Staff testimony filed in those two water utility cases to support quantification, noting that the "Public Staff has previously argued that approval of multi-year mechanisms that reduce the risk borne by water and wastewater utilities should result in a 20-basis point reduction in the allowed ROE." *Id.* at 287. The Commission did not accept the Public Staff position in either of the proceedings cited by witness Walters, and this downward adjustment is contrary to Commission's reasoning in the Orders in the 2022 Aqua Rate Case and the CWSNC Rate Case. Further, there is substantial evidence introduced in this case supporting DEP's position that no downward adjustment is warranted. Accordingly, the Commission rejects the downward adjustment theory.

In the Commission's Order in the 2022 CWSNC Rate Case, the Commission addressed and rejected the Public Staff's requested 20 basis point downward adjustment in otherwise applicable ROE and its holding was read into the record by Dr Morin:

> [T]he Commission is persuaded that this type of mechanism is prevalent across the country and within the proxy group. Although a WSIP is intended to reduce regulatory lag, the existence of similar mechanisms across the country and in the states where the proxy group utilities operate indicates

[14] DoD-FEA witness Reno did not make a specific downward adjustment to her rate of return on equity recommendation due to DEP's MYRP proposal but indicated that she had taken the MYRP proposal into account in setting rate of return on equity.

> that the comparative risk reduction associated with a WSIP[15] for CWSNC, in this case, is zero.

Tr. vol. 9, 20-21 (emphasis added)[16].

The Commission's conclusion is in line with witness Morin's academic work on this subject, which is summarized in his most recent book, Modern Regulatory Finance, published in late 2021. *See* DEP Redirect Morin Direct and Rebuttal Ex. 1. Tr. Ex. vol. 9. At the hearing in this proceeding Witness Morin summarized the three reasons why he asserts the presence of risk-mitigating mechanisms should not result in a reduction in the cost of equity as presented on pages 58-59 of his Direct and Rebuttal Exhibit 1. *Id.*

First, witness Morin asserts that the ROE in a rate case is being set based upon a proxy group of comparable companies, and the use of a proxy group takes into account similar risk mitigating mechanisms that are pervasive in the industry, so "the addition of any discreet adjustment would be unwarranted double counting of the effect of these mechanisms." DEP Redirect Morin Direct and Rebuttal Ex. 1 at 58, Tr. Ex. vol. 9. In sum he states that the "current market data reflects or embeds the presence of risk mitigators." Tr. vol. 9, 17. Second, he states that empirical studies in peer-reviewed academic journals have examined the impact of risk mitigators on the cost of equity, and the results show that there is no impact. *Id.* at 17-18. Third, risks that are diversifiable are not considered relevant in cost of capital estimates for investors, because by definition they can be eliminated through diversification, and risk mitigators are in fact diversifiable. *Id.* at 18.

DEP witness Morin, quoting from his book, summarized that a downward adjustment would be "double counting" as the "market-derived returns are estimated for market information on the cost of common equity for other comparable companies, which already incorporates the impacts of these mechanisms." Tr. vol. 9, 17-18 (quoting DEP Redirect Morin Direct and Rebuttal Ex. 1 at 59), Tr. Ex. vol. 9.

The Commission is persuaded that DEP has proven, by the greater weight of the evidence, that the impact of alternative ratemaking mechanisms like the PBR Statute is already incorporated into the analysis and a downward adjustment in otherwise applicable ROE would be inappropriate "double counting."

DEP Late-Filed Exhibit (LFE) No. 11 and LFE No. 14 illustrate the prevalence of alternative ratemaking mechanisms. DEP LFE No. 11 is a map demonstrating that alternative ratemaking mechanisms are widespread throughout the United States. In fact, of the 51 jurisdictions depicted (the 50 states plus the District of Columbia), only five have no alternative ratemaking mechanism in place. By contrast, 36 (over 70%), have two or more such mechanisms, including North Carolina, which has two (MYRP and

[15] A "WSIP" (Water and Sewer Investment Plan) is the water utility analog to an MYRP for electric utilities.

[16] The Commission reiterated this holding, in identical language, in its recent Order in the 2022 Aqua Rate Case. See Order at 62.

decoupling). The other eleven states have a single mechanism, either a future test year or specific capital trackers. The exhibit validates DEP witness Bateman's observation that in the United States:

> [A]lternative ratemaking regulation is the norm and, therefore, contrary to Witness Walters's assertion, implementation of a MYRP does not warrant a reduction to the Company's ROE since this change simply makes North Carolina's ratemaking practices more aligned with the rest of the country. Notably, every single company in Witness Walters's proxy group operates either entirely or partially in states that have adopted alternative regulation.

Tr. vol. 23, 159-60.

LFE No. 14 shows the 23 electric utility holding companies in witness Morin's peer group used in connection with his ROE recommendation and the alternative ratemaking mechanisms in the applicable jurisdiction. Tr. vol. 8, 349. The LFE illustrates witness Morin assertion that "the proxy group companies all operate in … states [that have alternative ratemaking mechanisms], and more than one state in many cases." *Id.*

DEP witness Bateman compared the alternative ratemaking mechanisms available in North Carolina under the PBR Statute with similar mechanisms available in other jurisdictions. DEP witness Bateman stated that "the focus should not be on whether DEP has a Multiyear rate plan, but rather, how the North Carolina PBR framework compares to alternative regulation in other states in terms of risk to the utility." Tr. vol. 23, 160. Witness Bateman asserted that "North Carolina's framework places more risk with the utility than the frameworks in some other states." *Id.* She provided numerous examples of how North Carolina's framework places risk on the utility. As an example, she compared states with formula rates and riders for significant capital investments that allow for true-ups of costs increases to North Carolina's PBR mechanism under which she contends electric utilities bear "all the risk of and financial impact associated with cost increases on projects in between rate cases." *Id.* Witness Bateman also stated that unlike the PBR Statute many other states' MYRP mechanisms provide for fully forecasted growth of both capital and associated O&M expense. Tr. vol. 15, 91-92. Finally, she noted that ESM in North Carolina's PBR Statute is asymmetrical in that it assures that customers receive 100% of earnings once the utility's earnings exceed 50 basis points of its allowed ROE, but the utility does not receive an earnings boost if it underearns. *Id.* at 92-93; Tr. vol. 23, 160-61; *See also* DEP Redirect Bateman Stillman Direct and Settlement Ex. No. 1, Tr. Ex. vol. 16.

Witness Bateman concluded her review with the observation that she saw nothing that makes North Carolina "less risky, in terms of the regulatory framework than other states on average across the country." Tr. vol. 15, 96.

The Commission agrees with DEP witnesses Bateman and Morin and concludes that substantial evidence supports the reasonableness of a rate of return on equity ranging from 9.75% to 10.0%, without a downward adjustment due to the MYRP. The

Commission is persuaded by the evidence that similar types of mechanisms are prevalent across the industry as well as within the proxy group. The Commission is also persuaded that elements of the North Carolina statute are distinguishable as compared to other jurisdictions, as pointed out by witness Bateman, in terms of allocation of risk between utility and customers. The Commission is mindful that one of the objectives of the MYRP is to reduce the lag in recovery experienced by the utilities, which, in theory, benefits the utility. However, the Commission concludes that given the utility has entered a capital intensive period of time as it manages the transition of its system, it is critical that the utility be in a position to access capital on reasonable terms and the Commission concludes that the availability of the MYRP makes DEP competitive in terms of its ability to access capital on reasonable terms.

Regarding the obligation in accord with the holding in *Cooper I* to inform its selection of a rate of return on equity within that range, the Commission will next address the impact of changing economic conditions on customers.

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of DEP witness Morin and Public Staff witness Walters addresses changing economic conditions at some length. Witness Morin provided detailed data concerning changing economic conditions in North Carolina, as well as nationally, and concluded that the North Carolina-specific conditions are "highly correlated" with conditions in the broader national economy. As such, witness Morin testified that changing economic conditions, both nationally and specific to North Carolina, are reflected in his rate of return on common equity estimates.

Public Staff witness Walters generally agreed with DEP witness Morin that as of the time of the filing of his testimony, economic conditions had improved in North Carolina. As the Commission has noted, customer impact due to changing economic conditions is embedded in ROE expert witness analyses. Witness Morin's analysis, which the Commission credits and to which the Commission gives weight, also indicates that even though the North Carolina and U.S. economies have contracted, economic conditions in North Carolina continue to be highly correlated to conditions nationally, and, therefore, continue to be reflected in the analyses used to determine the rate of return on equity.

The point is to see whether the econometric data relied upon by ROE expert witnesses captures the effects and impacts of changing economic conditions upon customers and the Commission concludes that, based on the evidence presented in this case, it does.

Based upon the general state of the economy and the need for the continuing affordability of electric utility service, and after weighing and balancing factors affected by the changing economic conditions in making the subjective decisions required, the Commission concludes that the rate of return on common equity of 9.8% will not cause undue hardship to customers even though some will struggle to pay the increased rates.

Indeed, affordability, especially for low-income customers, was a special focus of DEP and the intervening parties to this proceeding. As noted above, the Commission established the LIAC in its April 16, 2021, Order in the 2019 Rate Case and tasked the LIAC with addressing affordability issues for low-income residential customers. The efforts of the LIAC are apparent in this case and include the Affordability Stipulation as previously discussed in this Order. The provisions in the Affordability Stipulation, which includes the development of the CAP pilot, directly benefit customers with the least ability to pay in the current economic environment. In addition, as previously discussed in this Order, through the Payment Navigator program proposed in this proceeding, DEP will work closely with customers in need of assistance with managing bills and will connect those customers with sources of support and funding, based on the unique situation of the customer. While these programs will not ease the burden that electricity rates will place on certain of DEP's customers, the Commission expects these programs to provide a meaningful level of support to eligible customers. The Commission takes these facts into account in approving the 9.8% return on equity. However, the Commission also concludes, based on the evidence of record, that efforts to address energy burden and support for customers need assistance with their bills are but nascent. The LIAC allowed DEP and its stakeholders to generate data that illustrates the depth and breadth of the challenge in North Carolina. Work must continue to reach these customers and provide meaningful support both in terms of assisting customers use energy more efficiently so that bills are reduce and in terms of providing support to those customers when they are in need of bill assistance. The Commission recognizes the difficulties attendant to solving for these issues but emphasizes that the utility must continue this work. As has been previously expressed by this Commission, the electric utilities must pursue every opportunity presented by federal funding made available by the IRA and other federal legislation to support customers in need. The Commission has confidence that DEP, the Public Staff and stakeholders will identify such opportunities for customers and will develop programs that take advantage of every federal dollar that is available for customer support.

Considering the changing economic conditions and their effects on DEP's customers, the Commission recognizes the financial difficulty that an increase in DEP's rates may create for some of DEP's customers, especially low-income customers. The Commission is mindful that, as shown by the evidence, relatively small changes in the rate of return on common equity have a substantial impact on a utility's base rates. Therefore, the Commission has carefully considered changing economic conditions and their effects on DEP's customers in reaching its decision regarding DEP's approved rate of return on common equity.

The Commission also recognizes that provisions in S.L. 2021-165 may intensify the risks facing DEP as it continues to navigate the challenges associated with the change in the mix of electric generating resources and with new load patterns, including ensuing the continued reliable operation of the electric system, and to work toward the requirements of N.C.G.S. § 62-110.9. As DEP witness Bowman asserted,

> [I]t is simply indisputable that the tasks currently before the Company—implementing the energy transition within the construct of the Carbon Plan while simultaneously evolving nearly every aspect of its business and pursuing a complex merger—are unprecedented, imposing new and unique execution risks on the Company across all phases and aspects of its business that are inarguably more far-reaching and complex than anything the Company has ever pursued in the past.

Tr. vol. 21, 1200-01.

The need to invest significant sums to serve its customers requires DEP to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. And, in addition, as recent years have demonstrated, macroeconomic, geopolitical, extreme weather, public health, and other exogenous events beyond DEP's control may necessitate – and indeed have necessitated – the need for DEP to access and invest significant sums during atypical and volatile market conditions. The Commission takes note of DEP witness Newlin's testimony that, particularly in light of DEP's present credit metrics, ROE is one predicate (capital structure being another predicate, discussed in detail below) to the level of creditworthiness necessary to efficiently access the capital markets on reasonable terms during all market cycles, including periods of high volatility, which access ultimately lowers borrowing costs passed through to customers during such time. Tr. vol. 9, 112-13; Tr. vol. 22, 206-07.

The Commission must weigh the impact of changing economic conditions on DEP's customers against the benefits that those customers derive from DEP's ability to provide safe, adequate, and reliable electric service 24/7/365, regardless of macroeconomic, geopolitical, environmental, and public health events. Safe, adequate, and reliable electric service is essential to the well-being of the people, businesses, institutions, and economy of North Carolina. The Commission is mindful of the burden that electricity rates will place on many of DEP's customers and the contribution of the ROE to those rates, but the Commission must balance the burden against DEP's being in a position to access capital: (1) on reasonable terms; and (2) in moments when DEP most needs capital in order to provide reliable service.

The Commission concludes in the exercise of its independent judgment and discretion that a 9.8% rate of return on common equity is supported by the evidence and should be adopted. The hereby approved rate of return on common equity appropriately balances the benefits received by DEP's customers from DEP's provision of safe, adequate, and reliable electric service in support of the well-being of the people, businesses, institutions, and economy of North Carolina (which benefits are symbiotically linked to DEP's ability to compete in the capital markets to access capital on reasonable terms that will be fair to ratepayers) with the difficulties that some of DEP's customers will experience in paying DEP's adjusted rates. The Commission further concludes that a 9.8% rate of return on common equity will allow DEP to compete in the market for equity capital, providing a fair return on investment to its investor-owners. Accordingly, the Commission concludes, taking into account changing economic conditions and their

impact on customers, that the approved rate of return on common equity will result in the lowest rates constitutionally permissible in this proceeding.

Capital Structure

Summary of Evidence

In his direct testimony, DEP witness Newlin proposed using a capital structure of 53% members' equity and 47% long-term debt. Tr. vol. 9, 94. Witness Newlin testified that DEP's "specific debt/equity ratio will vary over time, depending on a variety of factors, including among other things, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, and dividend payments to the parent company." *Id.* As of December 31, 2021, DEP's capital structure was 53.9% common equity and 46.1% long-term debt. *Id.* at 95.

Witness Newlin discussed the current credit ratings and forecasted capital needs of DEP and emphasized the importance of DEP's continued ability to meet its financial objectives. *Id.* at 87. He noted that DEP faces substantial capital needs over the next several years so as to provide cost-effective, safe, reliable, and increasingly cleaner electric service to its customers well into the future, so DEP must therefore appeal to debt and Duke Energy's equity investors to attract the capital it needs. *Id.* at 98-99. He explained that investors – both debt and equity – have a variety of investment opportunities available to them and require a return commensurate with the risk they incur, warning that they will invest elsewhere if they feel the expected return provided by a company for a given amount of risk is inadequate. *Id.* at 86. He further explained that lower credit quality weakens a company's attractiveness as an investment opportunity relative to companies with higher credit quality and similar return profiles. *Id.* at 86-87. As such, witness Newlin testified it is critically important that DEP maintain strong, investment-grade ratings to assure its financial strength and flexibility and ensure access to capital on reasonable terms. *Id.* at 96.

Discussing DEP's financial objectives, witness Newlin addressed specific objectives that support financial strength and flexibility, including maintaining 53% common equity for DEP on a financial capitalization basis; ensuring timely recovery of prudently incurred costs; maintaining sufficient cash flows to meet obligations; and maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. *Id.* at 97-98. He further testified that the ability to attract capital (both debt and equity) on reasonable terms is vitally important to DEP and its customers, and each of these specific objectives helps DEP both to maintain its investment-grade credit ratings and to meet its overall financial objectives. *Id.* at 87-88.

Intervenor witnesses disputed witness Newlin's recommendation. Public Staff witness Walters, CUCA witness O'Donnell, and DoD-FEA witness Reno all testified that DEP's proposed 53/47 capital structure exceeded the equity ratio for all proxy group companies. Tr. vol. 16, 245 (Walters); Tr. vol. 21, 592 (O'Donnell); Tr. vol. 21, 360 (Reno). The testimony of witnesses Walters and Reno also noted that the 53/47 recommendation

was inconsistent with DEP's observed capital structure at various points in time. Tr. vol. 16, 246 (Walters); Tr. vol. 21, 360 (Reno). Witnesses O'Donnell, Reno, and Gorman testified that the 53/47 proposal exceeded the average capital structure authorized by other utility commissions. Tr. vol. 21, 360 (Reno); Tr. vol. 21, 593-94 (O'Donnell); Tr. vol. 21, 405, 408 (Gorman).

These witnesses' capital structure recommendations were as follows: Walters — 52/48 (Tr. vol. 16, 247); O'Donnell — 50/50 (Tr. vol. 21, 568); Reno — 52/48 (Tr. vol. 21, 360); and Gorman — 52/48 (Tr. vol. 21, 405).

NCJC, et al. witness Ellis took a different tack, recommending a capital structure of 58% equity and 42% debt. Tr. vol. 21, 1071. As noted above in connection with the Commission's discussion of ROE evidence, witness Ellis testified that ROE and capital structure are interrelated and must be addressed together. *Id.* at 1056-57. Accordingly, his 58/42 capital structure recommendation goes hand-in-hand with his 6.0% ROE recommendation. *Id.* at 1071. He indicated that this combination would minimize customer costs while meeting investor return expectations. *Id.*

In his rebuttal testimony, DEP witness Newlin took issue with the intervenor witness recommendations. He observed that the reliance of witnesses Walters, O'Donnell, and Reno on capital ratios of proxy group companies was misplaced, because the proxy companies are all publicly traded holding companies, not utility operating companies. Tr. vol. 22, 169. He testified that it is inappropriate to compare DEP's capital structure to the holding company capital structures, because the risk profiles are very different. *Id.* at 170. The appropriate comparison is to other utility operating companies. Witness Newlin performed that comparison for witness Morin's proxy group, which was essentially the same for the other rate of return on equity expert witnesses and presented the results in Newlin Rebuttal Exhibit 1. Tr. Ex. vol. 22. The results show that the average capital structure for operating utilities is 53.3% equity/46.7% debt – consistent with DEP's proposal. Tr. vol. 22, 172. He pointed to the Commission's previous rejection of the use of parent company structures as opposed to operating company structures in determining the operating utility's appropriate equity/debt ratio. *Id.* at 172-73.

Witness Newlin further testified that witnesses Walters's and Reno's comparisons of DEP's proposed capital structure with DEP's actual capital structure at a specific point in time are inappropriate. *Id.* at 173. He explained that it is reasonable to expect DEP's capital structure to fluctuate above and below the target equity ratio, and that merely selecting a point in time is not representative of how DEP intends to capitalize its business in the long-term. *Id.* at 174. Moreover, the specific points in time utilized by witness Walters rely on a surveillance report which includes current maturities of long-term debt which are excluded for ratemaking purposes. *Id.*

Witness Newlin disputed the manner in which witnesses O'Donnell, Reno, and Gorman compare DEP's proposed capital structure with allowed common equity ratios granted by other state regulators, noting that their presentations are overly simplistic and

misleading. *Id.* at 175. He explained that their considerations fail to give proper weight to trends of rising equity components not reflected in their historical observations. *Id.* at 176.

Witness Newlin also presented an analysis of the intervenor capital structure recommendation with the lowest equity ratio component, proposed by witness O'Donnell. He noted that selection of an optimal capital ratio requires balance between affordability and access to the capital markets. He noted that a strong capital structure and adequate ROE provide the balance sheet protection and cash flow generation to support high credit quality. This in turn creates financial flexibility to efficiently access the capital markets on reasonable terms during all market cycles, including periods of high volatility, which ultimately lowers borrowing costs passed through to customers. *Id.* at 180. He testified that witness O'Donnell fails to consider the impact his 50/50 capital structure recommendation would have on DEP's credit metrics and potentially its credit ratings. *Id.* Witness Newlin then presented an analysis showing the negative impact upon DEP's credit ratings of the 50/50 recommendation, concluding the recommendation along with witness O'Donnell's ROE estimate would further stress DEP's already distressed credit metrics and cash flows, with negative consequences to DEP's credit ratings and cost of debt. *Id.* at 181-88.

Witness Newlin also criticized witness Ellis' 6.0% rate of return on equity/58% equity layer recommendation, noting that with an ROE that low DEP would not be able to effectively compete for capital. *Id.* at 193. Witness Newlin presented a table showing alternate ROE comparisons of southeastern utilities, as follows:

Table 4: Authorized ROE Comparison of Peer Utilites in the Southeast since 2020

Regulated Utility	State	Docket/Case No.	Year of Order	Current Authorized ROE
Virginia Electric and Power	NC	E-22, Sub 562	2020	9.75%
Alabama Power Company	AL	reported by S&P, under RSE mechanism	2021	11.88%(1)
Dominion South Carolina	SC	2020-125-E	2021	9.50%
Duke Energy Carolinas	NC	E-7, Sub 1214	2021	9.60%
Georgia Power	GA	44280	2022	10.50%(2)
Florida Power & Light	FL	20210015 - ROE Trigger	2022	10.80%(3)
Duke Energy Florida	FL	20220143-EI	2022	10.10%(4)
Tampa Electric Co.	FL	20220122-EI	2022	10.20%(5)
Duke Energy Progress	SC	2022-254-E	2023	9.60%
Average				**10.21%**

Source: S&P Capital IQ, Past Rate Cases pulled on April 4, 2023.

(1) Alabama Power has a formula rate mechanism that allows for annual adjustments, and they have a variety of mechanisms to allow for the inclusion of new plant. Under this mechanism, they are allowed a relatively high ROE (S&P reported 11.88% in year 2021) that is balanced against limited annual rate adjustments with certain caps.

(2) Authorized retail ROE set under the 2022 Alternative Rate Plan approved by the Georgia Public Service Commission and evaluated against a range of 9.50% to 11.90%. Any retail earnings above 11.90% will be shared with Georgia Power retaining 20%, 40% applied to reduce regulatory assets, and 40% directly refunded to customers.

(3) ROE Trigger increased authroized ROE to a midpoint of 10.80% from 10.60%

(4) Originally approved ROE band was 8.85% to 10.85%. The ROE band will increase by 25 basis points beginning in 2023 as a result of the average 30-year U.S. Treasury rate increasing by more than 50 basis over a six-month period.

(5) Originally approved ROE band was 9.00% to 11.00%. The ROE band will increase by 25 basis points beginning in 2023 as a result of the average 30-year U.S. Treasury rate increasing by more than 50 basis over a six-month period.

Id. at 195.

Finally, witness Newlin provided an overview of market dynamics since DEP's last rate case, noting the dramatic changes in economic conditions, including persistently high inflation, geopolitical issues like the war in Ukraine, and bank failures. *Id.* at 196. The Federal Reserve has responded to inflation by dramatically raising short term interest rates, and long term rates have also spiked and remain volatile. He noted that this heightened level of market volatility and uncertainty has led to an unprecedented number of zero issuance days in the primary debt capital markets. Witness Newlin stressed the value during these times of high credit quality and strong investment-grade credit ratings, which allow Companies to not only access the market, if needed, but also provide flexibility to wait for more optimal market conditions. *Id.* at 196-97. In his testimony summary witness Newlin noted that DEP's existing strong investment grade credit ratings constitute a form of insurance against downgrades that will be the likely consequence of weakening DEP's financials and noted further that downgrades only work to the detriment of DEP and its customers. *Id.* at 201.

Discussion and Conclusions

For the reasons set forth herein, the Commission approves DEP's proposed capital structure of 53.0% equity and 47.0% long term debt.

The Commission is not persuaded by witness Ellis' recommendation. In the Commission's view, his testimony on capital structure is far outside the mainstream, just as it was for ROE. While the Commission appreciates – and no party disputes – witness Ellis's point that capital structure and rate of return on equity are related, the Commission is concerned that an ROE so low, even if connected to a high equity ratio, will render DEP at a severe disadvantage when competing for capital. The Commission is concerned that DEP will not find many equity investors willing to invest in an electric utility that runs nuclear plants and faces significant challenges and capital needs with respect to spearheading S.L. 2021-165's energy transition with a 6.0% rate of return on equity, no matter what the equity ratio – especially when, as indicated by DEP Redirect Newlin Rebuttal Exhibit 2, those same investors can invest in much less risky utility bonds yielding 5.24%. Tr. vol. 23, 47; Tr. Ex. vol. 22.

Turning next to the recommendations of the other witnesses, the Commission notes while witnesses Gorman, Reno, and Walters support use of the stipulated equity later from DEP's prior rate case, much of their testimony in support of lowering the equity layer from DEPs request is premised upon comparisons to the capital structures of publicly traded holding companies. The Commission has repeatedly rejected the use of holding company capital structures in the past. *See, e.g.,* Order Granting General Rate Increase and Approving Amended Stipulation, issued on December 7, 2009 in Docket No. E-7, Sub 909, 27-28. Moreover, witness Newlin persuasively establishes that DEP's proposed 53/47 capital structure is right in line with the capital structures of the utility operating companies that are subsidiaries of the holding companies in Dr. Morin's proxy group, which is essentially the same as all of these witnesses' proxy groups. *See* Newlin Rebuttal Ex. 1, Tr. Ex. vol. 22.

The seemingly slight difference between DEP's 53/47 proposal and the Public Staff's 52/48 proposal masks consequential impacts. Those impacts persuade the Commission that 53/47 is the optimal structure that appropriately balances affordability and DEP's access to capital on reasonable terms. With DEP's credit metrics as stressed as they are, further downward pressure in the form of a reduced equity layer and increased debt is decidedly not in the best interests of either DEP or its customers.

The credit stressors experienced by DEP are in some respects being felt industry wide. In his direct testimony, witness Morin referenced the "perfect storm" facing electric utilities like DEP: (1) slowing or even declining electricity growth in energy consumption; (2) at a time in which record amounts of new capital must be raised to replace aging infrastructure, improve reliability, and deliver renewable generation; (3) coupled with the need to implement a transition away from fossil fuel (particularly coal) and toward renewables, including electrification of the transportation sector; and (4) and layering on further the need to build new transmission infrastructure to strengthen the grid against

weather events increasing in frequency and ferocity, as well as new renewable generation resources. Tr. vol. 8, 91-92.

As witness Bateman testified, DEP faces multiple risks on multiple fronts including risks associated with investment and new technologies; risks associated with operating a system that must be "on" 24/7/365 with new types of generation, including increasing amounts of solar; and risks associated with getting the retirement of existing coal generation "just right." Tr. vol. 15, 97-98. These risks all highlight the execution and operational risks facing DEP in connection with the mandates of S.L. 2021-165. Witness Bowman addressed this issue as well, as noted in the return on equity discussion above. Moving forward, these risks impose upon DEP the obligation to navigate a fast-changing landscape to secure ready access to capital upon reasonable terms, to ensure that it can make the necessary capital investments to ensure reliable and affordable service to its customers.

Credit rating agencies have noted these stressors, both on a national and a DEP-specific basis. On the national front, Moody's published in November 2022 an industry-wide report highlighting the agency's revision of the entire regulated utility sector outlook from stable to negative. *See* DEP Redirect Newlin Direct Ex. 3, Tr. Ex. vol. 10. The report highlights that the industry as a whole is confronting numerous financial pressures at a time when Moody's expects "the sector to maintain elevated capital spending focused on reducing carbon emissions to make progress toward net zero goals and overall system reliability" – precisely the execution risks DEP faces in connection with the mandates of S.L. 2021-165.

Specifically regarding DEP, Moody's has taken two very recent actions, both of which highlight the immediate credit metric challenges DEP faces. First, in April 2023 Moody's published a "Ratings Action" report (DEP Redirect Newlin Direct Exhibit 1) affirming DEP's A-level rating but at the same time issuing an explicit warning with regard to the principal credit metric utilized by Moody's, the ratio of Funds From Operations (FFO) to debt (FFO/Debt)[17]. Tr. Ex. vol. 10. In its April 2023 Ratings Action Moody's indicated that it was raising its FFO/Debt downgrade threshold for DEP from 20.0% to 21.0%, meaning that while it had in the past forecast a potential downgrade in DEP's credit rating if the FFO/Debt metric stayed below 20.0% on a sustained basis, it was now forecasting a potential downgrade if the metric stayed below 21.0% on a sustained basis. This is a particularly worrisome development because, as Company witness Newlin pointed out during his direct testimony, DEP's FFO/Debt ratio has been below 21.0% for a number of years. Tr. vol. 9, 17-18. In other words, DEP is already operating below the Moody's raised downgrade threshold and has already been doing so on a sustained basis. *Id.* at 18-19.

Between witness Newlin's appearance on direct on May 5 and his appearance on rebuttal on May 16, Moody's issued its May 2023 updated Credit Opinion regarding DEP, replacing its Credit Opinion issued in March 2022 (introduced into evidence as both Public

[17] In Moody's parlance FFO/Debt is called "preworking capital cash flow to debt" (Tr. vol. 9, 115), or "CFO pre-WC to debt." Both FFO and CFO pre-WC mean the same thing and are a measure of cash flow. *Id.*

Staff Cross-Examination Morin Direct and Rebuttal Exhibit No. 15 and DEP Redirect Newlin Direct Exhibit 2). Tr. Ex. vol. 10. In the updated Credit Opinion, Moody's explicitly referenced as factor that could lead to a downgrade the FFO/Debt ratio "remaining below 21% in 2023." DEP Redirect Newlin Rebuttal Ex. 1, 2; *see also* Tr. vol. 23, 36-37. Accordingly, Moody's not only alluded to its raised download threshold, but pointedly referenced 2023 – this very year.

The potential for downgrade is not a theoretical issue. The actions by Moody's beginning with its sector outlook publication in November 2022, running through its April 2023 raising of DEP's downgrade threshold, and culminating with its May 2023 updated DEP Credit Opinion are a series of escalating warnings.

Witness Newlin noted in his testimony that to ensure reliable and cost-effective service, and to fulfill its obligations to serve customers, DEP must continuously plan and execute major capital projects, and must be able to operate and maintain its business without interruption and refinance maturing debt on time, regardless of financial market conditions, even (and perhaps especially) in times of market volatility. Tr. vol. 9, 102. Customers benefit from DEP's financial strength, because its strong investment-grade credit ratings provide DEP with greater access to the capital markets on reasonable terms during such periods of volatility. *Id.* Responding to questions from Chair Mitchell, witness Newlin recounted a recent example of market dislocation, resulting from the collapse of Silicon Valley Bank, in which other Duke Energy subsidiaries were able to time entry into the market for the benefit of their customers, and he noted that only a "utility with good strong credit quality is able to do that." Tr. vol. 22, 207. He similarly alluded to market dislocation at the initial stages of the COVID-19 pandemic when Duke utilities were able to flexibly maintain market access when other utilities were unable to access the credit markets. *Id.* at 208. And widening credit spreads between higher- and lower-rated utilities mean that downgrade will have cost consequences for customers even if DEP were able to achieve access to the capital markets. *Id.* at 205; tr. vol. 23, 45-48.

Witness Newlin likened the flexibility derived from DEP's existing strong investment grade credit ratings as "a form of insurance against downgrades that will be the likely consequence of weakening the Company's financials," and noted that "downgrades only work to the detriment of DEP and its customers." Tr. vol. 22, 201 (emphasis in original). He cautioned against the Commission's taking action to weaken this insurance policy, "perhaps with unintended consequences." *Id.* The Commission heeds this warning, and the escalating series of warnings from Moody's, and finds that now is decidedly not the time to weaken DEP's credit profile and invite a credit downgrade. DEP must attract capital on reasonable terms in order to finance investment needed for the continued reliability of the system. Weakening DEP's capital structure or awarding too-low an ROE will make attraction of necessary capital that much more difficult – and certainly more expensive.

Accordingly, the Commission accepts witness Newlin's recommendation that DEP's capital structure be composed of 53.0% equity and 47.0% long term debt.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 52-56

COVID Deferral

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Bowman, Quick, Abernathy, Speros (together as a panel), and Jiggetts, Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Deferral Docket

In August of 2020, DEP and DEC (together, Duke) jointly petitioned the Commission for approval of orders for regulatory accounting purposes authorizing both Companies to establish a regulatory asset to account for incremental costs resulting from the unprecedented COVID-19 Pandemic and declared State of Emergency, so that such costs can be deferred pending further action by the Commission in the next general rate case filed by DEP and DEC. Joint Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for Approval of Accounting Orders to Defer Incremental COVID-19 Expenses, Docket Nos. E-2, Sub 1258 and E-7, Sub 1241 (August 7, 2020) (Covid Deferral Docket). DEC and DEP each requested permission to create a regulatory asset to defer costs associated with customer fees waived, bad debt expenses, employee stipends and safety-related costs, remote work costs, and other costs, including overtime and related call center costs.

The Public Staff filed comments the Covid Deferral Docket opposing Duke's request, arguing among other things that Duke had not substantiated a need for a deferral of the costs enumerated and recommending the Commission deny the request. Further, the Public Staff stated that if the Commission allowed Duke to defer costs, Duke should offset such costs with COVID-related savings such as federal tax credits and reductions in operating expenses.

The Commission granted the request to defer incremental costs and waived customer fees associated with the COVID-19 Pandemic for recovery in a future proceeding in its December 21, 2021 Order Approving Deferral Request (Deferral Order), in Docket Nos. E-2, Sub 1258, E-7, Sub 1241. The Commission noted the unique nature of the request, the severity of the ongoing pandemic, and the fact that many of the actions taken by the Companies were in part due to government mandates imposed upon Duke intended to ease both the financial and public health impacts of the pandemic on North Carolina and its citizens who might likely have been displaced from their homes. Deferral Order at 13.

The Commission determined that it would be patently unfair to penalize Duke by not allowing an opportunity to justify recovery of these costs in a future rate case and the Commission concluded that the costs allowed to be recovered may be amortized over a period of time determined in the future rate cases.

Although the Commission allowed Duke to include carrying costs on the deferred amounts for accounting purposes, the Commission concluded that the rate of that return, if any, and the amount to which that return is applied will be subject to determination in that future rate case.

Summary of Evidence

DEP Direct and Supplemental Testimony

In the present proceeding, DEP now seeks recovery of its deferred incremental COVID-related costs. In her direct testimony, DEP witness Jiggetts presented DEP's request. Witness Jiggetts explained that DEP deferred and requests to recover: (1) customer fees waived, (2) bad debt charge-offs, (3) employee stipends to cover unplanned expenses associated with the COVID pandemic, (4) costs related to employee safety, (5) costs related to remote work, and (6) miscellaneous costs, such as employee overtime. Tr. vol. 13, 197-99. Witness Jiggetts maintained that the costs included in the deferral are reasonable and prudent costs that were incurred as DEP provided its essential public service during the pandemic. *Id.* at 199.

In her direct testimony, DEP witness Quick explained the efforts DEP undertook to support its customers throughout the pandemic and the return to normal billing practices. Tr. vol. 7, 81-83. Witness Quick explained that DEP suspended service disconnections and waived fees for card payments, walk-in pay location payments, late payment charges, and insufficient funds. *Id.* at 81. Witness Quick also detailed how DEP worked with assistance agencies and customers on an individual basis to connect qualifying customers with assistance funding where possible. *Id.* Witness Quick described DEP's expanded outreach campaign efforts and, in particular, detailed the ways in which DEP adapted its customer operations resources to provide a more tailored experience for customers and utility assistance agencies. *Id.* at 82.

DEP witness Speros testified in support of DEP's bad debt calculation. Tr. vol. 13, 51-52. Witness Speros explained that the moratorium on disconnections and late payment fees led to an increase in the number and amounts of past due accounts outstanding, which in turn lead to increased bad debt expense. *Id.* Witness Speros testified that the deferred bad debt expense was calculated as the total amount of incremental bad debt expense exceeding the amount already being recovered in base rates from the period starting in March 2020 through the capital cut-off date in this case. *Id.* at 52. Witness Speros also explained that DEP is continuing to incur impacts to business operations from the pandemic, namely that charge-offs related to COVID delinquencies are ongoing and will continue to be. *Id.* at 53.

Witness Jiggetts explained that DEP's additional deferred expenses include employee safety-related costs, costs for remote work, employee stipends, and other miscellaneous costs. Tr. vol. 13, 197. She explained that because DEP is an essential service provider, it was not an option for some of DEP's employees to remote work. Witness Jiggetts further explained that DEP provided, and will continue to provide,

employees with the appropriate personal protective equipment, and incurred additional incremental costs for increased cleaning and sanitation supplies, health care, as well as for testing and temperature checks. *Id.* at 198. For those employees who could work from home, witness Jiggetts testified that DEP incurred additional costs for remote work, including costs for expanded conference line capacity, increased network bandwidth, other required information technology improvements, expanded video conferencing licenses, and increased company cellular telephone and data usage. *Id.* at 198-99. Lastly, for certain eligible employees, witness Jiggetts stated that DEP provided a one-time cash payment of $1,500 to help with unplanned expenses associated with COVID-19. Witness Jiggetts also clarified that DEP seeks to recover other expenses related to overtime costs needed to implement COVID-19 guidelines to ensure employee safety and increased costs due to expected increased call volume at call centers when normal billing practices resume. *Id.* at 199.

Witness Jiggetts testified that the proposed new rates requested in this proceeding include recovery of costs deferred from March 2020 through April 2023, and that the adjustment normalizes revenues for waived late fees that will be collected going forward, amortizes the deferred costs over a three-year period, adjusts test year expenses to include certain incremental employee costs that were previously deferred and includes the deferral balance, net of one year of amortization and deferred taxes, in rate base. *Id.* In her third supplemental direct testimony, witness Jiggetts updated DEP's amortization amount for the COVID deferral to include actual amounts realized through March 31, 2023.[18] Tr. vol. 13, 247.

The Public Staff Direct and Supplemental Testimony

In their direct testimony, Public Staff witnesses Zhang and Boswell recommended that the Commission adjust DEP's revenue requirement to remove DEP's proposed COVID deferral due to significant questions regarding the eligibility, accuracy, and reasonable quantification of the costs included in the deferral and the savings and cost offsets DEP chose not to net against the COVID expenses. Tr. vol. 19, 65. Witnesses Zhang and Boswell commented that during their review of several major O&M expenses they found COVID-related cost savings in employee expenses and printing which were not netted again the deferred COVID costs. They stated that DEP was offsetting these savings against reduction in customer load, unfavorable weather, and excess storm costs, none of which were the causation of the savings. *Id.* at 66.

Witnesses Zhang and Boswell noted that DEP received the following credits and delayed payments as a result of the pandemic: (1) Employee Retention Credit (ERC); (2) delayed payment of employer portion of social security tax; and (3) Accelerated Alternative Minimum Tax (AMT). *Id.* at 67. The witnesses explained that Section 2301 of the federal CARES Act created a refundable ERC of up to $5,000 per eligible employee taken against the employer's share of the Social Security Tax on Qualified Wages paid from March 13, 2020, through December 31, 2020. *Id.* Witnesses Zhang and Boswell

[18] See fn. 2.

further stated that the CARES Act amended Title 26 of the Internal Revenue Code to allow the entire AMT credit carryforwards to be refundable to taxpayers in either the 2018 or 2019 tax year. Witnesses Zhang and Boswell noted that DEP reported that the AMT credits were generated by non-regulated operations of Duke Energy and, as such, were not attributable to DEP. *Id.* at 68.

Witnesses Zhang and Boswell testified that DEP is unable to provide any and all costs savings associated with the pandemic; thus, the Public Staff cannot calculate an appropriate amount for deferral. Additionally, the witnesses expressed concerns regarding the types of charges deferred reiterating the same concerns the Public Staff expressed in its comments filed in the Deferral Docket. *Id.* at 69. With regard to the employee stipends, witnesses Zhang and Boswell testified that this one-time payment, does not appear to include a verification by DEP as to the expenses paid, and constitutes goodwill to some employees on the part of DEP, not a cost that should be borne by ratepayers. *Id.*

Witnesses Zhang and Boswell rebutted DEP's assertion that its call center costs have increased, instead testifying that based on the Public Staff's review of the call center volumes and labor costs, including overtime, over the last five years, the volume and costs has been steady, with costs and volume declining in 2021 and 2022. *Id.* at 69. They testified, concerning costs for remote work, that while DEP incurred some additional costs with the initial rollout, remote work is now part of DEP's regular work offerings, and DEP has not offset any of these increased costs with associated decreases in office expenses. The witnesses removed the costs associated with safety personal protection equipment because DEP indicated that the amount included in the original filing will not be an ongoing amount. *Id.* at 71. Witnesses Zhang and Boswell also removed the overtime for the call center as their review indicated the level sought by DEP was not above the amounts already included in DEP's cost of service. *Id.* They also expressed concern regarding the reserve percentage DEP is utilizing to estimate its bad debt expense because DEP is still collecting a portion of the uncollectible amount through various collection agencies. *Id.* at 70.

In their supplemental and settlement testimony, Public Staff witnesses Zhang and Boswell again recommended removal of DEP's COVID deferral from the revenue requirement and updated their recommended removal amount to account for amounts included by DEP through February 28, 2023. *Id.* at 89. The witnesses again reiterated that the Public Staff opposes DEP's recovery of its deferred expenses because it did not net its COVID-related cost savings against the actual costs incurred. *Id.* at 93.

DEP Rebuttal Testimony

On rebuttal, DEP's COVID Panel, consisting of witnesses Bowman, Quick, Abernathy, and Speros, all testified to provide further detail and context for DEP's pandemic response and COVID-related costs incurred. Tr. vol. 21, 1263-64. The Panel stated that the vast majority of the deferred costs DEP seeks to recover result directly from customer inability to pay and the governmental response to that inability to pay. They

explained that non-payment ordinarily would have been met by discontinuance of service, but actions both of the Governor of North Carolina and the Commission removed service disconnection as an option for DEP. *Id.* at 1264.

Witness Bowman detailed DEP's initial and ongoing response as an essential service provider. Witness Bowman explained DEP's actions in response to federal, State, and Commission direction, including Governor Cooper's executive orders and the Commission's moratorium on disconnections. *Id.* at 1266-67. Witness Bowman also provided a brief background on the Deferral Docket and the Commission's Deferral Order, which approved DEP and DEC's request to establish a regulatory asset for the purposes of deferring the incremental costs associated with the COVID-19 pandemic for final determination in a future rate case. *Id.* at 1268. She stated that the Deferral Order also required DEP to periodically file reports to update the Commission concerning the actual amounts deferred. *Id.* DEP witness Quick details the ways in which DEP adapted its customer support operations to serve the unique needs of customers associated with the pandemic. *Id.* at 1272-76.

DEP witness Abernathy included in her portion of the prefiled COVID Panel rebuttal testimony a chart detailing the deferred costs as of March 17, 2023, the date DEP's second supplemental testimony was filed:

Deferred Incremental COVID-19 Costs	**$ in Millions**	**% of total**
Customer fees waived	$27.1	29.1%
Bad debt expense	$57.3	61.6%
Employee safety related costs	$4.0	4.3%
Costs for remote work	$0.6	0.7%
Employee stipends	$0.7	0.8%
Other (primarily call center costs)	$3.3	3.5%
Total Incremental COVID-19 Costs deferred	$93.0	100.0%
Accrued carrying costs	$12.0	
COVID Deferral projected balance as of rates effective	$105.0	

Id. at 1280.

According to DEP, the requested $105.0 million in deferred incremental COVID-related costs translates to approximately 124 basis points, excluding any impacts from lost revenues. *Id.* Witness Abernathy testified that as of the filing of the third supplemental testimony (April 18, 2023) the projected balance as of the date rates would go in effect had grown to approximately $107 million, mainly because of an increase in the amount of bad debt expense. *Id.* at 1307. She commented that the spike in bad debt expense occurred in connection with the expiration in March 2023 of 12-month repayment plans DEP automatically enrolled customers into as of the time (March 2022) when the extended winter moratorium on disconnection finally ended. *Id.* at 1353.

Witness Abernathy explained that over 90% of the deferred costs are attributable to waived customer fees and bad debt expenses. She notes that these incremental costs were primarily the result of government-issued moratoriums imposed on DEP. *Id.* at 1282. Witness Quick explained that DEP waived approximately $27 million in customer fees, launched extensive outreach campaigns to bring awareness to the available customer assistance, expanded the eligibility for the Winter Moratorium and extended its length. *Id.* at 1272-73. The COVID Panel testified that the remaining categories of expense are also clearly pandemic-related, in that they were incurred in order for DEP, as a provider of an essential service, to fulfill its obligation to continue operation 24 hours a day, seven days a week despite the pandemic. Witness Bowman stated that more than 40% of DEP's workforce had to show up, in person, at work, at power plants and other facilities, or to repair damage following storms. *Id.* at 1319. She noted that in doing so those employees had to be furnished with protective gear, cleaning supplies, sanitizing supplies, and COVID testing services and nursing case management. Further, witness Bowman testified that DEP installed barriers at the workstations located at various operating plants so employees would not transmit the coronavirus. *Id.* at 1321. Witness Abernathy stated that these costs are captured in the category "employee safety related costs." *Id.* at 1281.

The COVID Panel testified regarding the challenges faced by DEP's customer service representatives, who ordinarily would work in call centers but had to transform themselves essentially overnight into a virtual workforce working from their homes – homes that in large measure were not set up with home-office facilities – while simultaneously dealing with childcare and other family-related issues exacerbated by the pandemic. They noted that costs associated with these challenges are captured in the employee stipends, which were distributed to hourly-paid call center employees costs related to the pandemic such as increased childcare, home-office equipment, and home internet access.[19] *Id.* at 1282, 1325-26. They explained that the stipends served as an inexpensive means of retaining essential employees, as witness Quick noted, "to try to keep them and help them through this unprecedented time that we were all going through … just a way of really supporting our hourly employees at the call center." *Id.* at 1326. The COVID Panel testified that DEP also incurred costs related to remote work generally, such as expanded conference line capacity, increased network bandwidth, other required information technology improvements, expanded video conferencing licenses, and increased company cellular telephone and data usage. *Id.* at 1281-82.

Regarding regulatory treatment of COVID-19 costs in other jurisdictions, the COVID Panel testified that as of the time the reply comments were filed in the Deferral Docket (November 30, 2020) commissions in 32 states and the District of Columbia had permitted cost deferral in response to requests from regulated utilities subject to their jurisdiction. They stated that since then, several state commissions have begun to allow recovery of deferred costs. They noted that the Georgia Public Service Commission

[19] Call center-related costs are also captured in the "call center" category, which relates to incremental increases in workload and the need to retain outside vendors as the centers began to "return to normal" following the easing of the shutdown moratoriums. Tr. vol. 21, 1277-79.

recently permitted recovery of approximately $25 million in deferred COVID-related costs over a three-year amortization period.[20] *Id.* at 1270.

In response to the Public Staff's testimony that DEP's request for cost recovery of incremental deferred COVID-related costs should be denied because DEP has not offset these costs with COVID savings, the COVID Panel testified that the Deferral Order requires only that DEP track the costs being deferred. The Panel did note that in South Carolina DEP was required to track and report quarterly both COVID-19 related savings and net lost revenues (NLRs) on a South Carolina retail basis in 2020. *Id.* at 1288. The Panel stated that because of this South Carolina requirement, DEP has tracked incremental savings due to COVID and provided these amounts to the Public Staff. They explained that DEP's estimates included two categories of expenses that resulted in financial savings attributable to the COVID-19 pandemic. First, DEP experienced reduced employee expenses as compared to budget, primarily related to reductions or elimination of travel and expenses associated with normal operations while DEP's employees were required to work remotely and adhere to travel restrictions, etc. Second, DEP experienced reduced printing and postage costs while the various government-imposed moratoriums were in place and DEP was not disconnecting customers and thus not mailing required notifications. *Id.* at 1289.

The COVID Panel stated that in 2020, DEP estimated approximately $4.5 million, on a North Carolina retail basis, in O&M expense savings attributable to COVID-19. DEP estimated NLRs in 2020 to be approximately $28 million, on a North Carolina retail basis, compared to budget, more than offsetting the savings reductions that the Public Staff suggests. *Id.* The COVID Panel maintained that the negative impact of NLRs was ignored by the Public Staff in its testimony.

The Covid Panel also addressed the assistance provided by the federal CARES Act. With respect to the accelerated AMT, the COVID Panel maintain that the Public Staff's argument that this credit should impact the COVID-19 deferral is simply incorrect as "not a single dollar of the AMT refunds is attributable to DEP; rather, the refunds all relate to other subsidiaries of Duke Energy Corporation". *Id.* at 1291. Regarding the delay in payment of the social security tax for the period April through December 2020, the COVID Panel noted that this was only a temporary deferral from the government and was fully paid by December 31, 2022. *Id.* They stated that although the Public Staff believes that DEP should have offset the COVID deferral for the working capital impacts of the delay in payment, witnesses Boswell and Zhang did not provide a quantification of their estimate of that amount. The COVID Panel estimates that the carrying cost benefit between April 2020 and December 2022 was approximately $2 million on a North Carolina Retail basis. *Id.* Related to the ERC, the COVID Panel stated that DEP filed for ERCs under the CARES Act and that all claims have been filed attributable to its operations from March 13, 2020, through September 30, 2021. The COVID Panel contended that even if these

[20] See Order Adopting Settlement Agreement as Modified, Docket No. 44280 (December 20, 2022); see also Direct Testimony of Aaron P. Abramovitz, Sarah P. Adams, Adam D. Houston, and Michael B. Robinson, Docket No. 44280, at 46-47 (June 24, 2022).

benefits to DEP (excluding the AMT which is not a benefit attributable to DEP) should be netted against costs, they should in that case also be netted against NLRs. The Panel maintained that these benefits do not overcome NLRs even when added to the $4.5 million DEP estimates is COVID-related savings. *Id.* at 1292.

Witness Abernathy maintained that the Public Staff's recommendation is one-sided and asymmetrical in its focus on DEP's apparent savings but omits any discussion of NLRs. *Id.* at 1271. Witness Abernathy explained that in 2020, DEP faced challenges in addition to the pandemic, such as mild weather that also resulted in substantially lower than projected revenues. She also testified concerning increased expense due to higher-than-normal storm restoration costs. Witness Abernathy testified that when faced with the prospect of revenue loss and in keeping with its focus on managing O&M expenses for the benefit of customers, DEP, as a routine part of its business, identifies and implements a suite of cost mitigation measures. *Id.* at 1271.

Witness Abernathy testified that total O&M cost reductions for 2020 amounted to $62 million on a North Carolina retail basis. *Id.* at 1295. She further testified that revenue impacts from COVID and mild weather amounted to $71 million on a North Carolina retail basis, and when added to an additional impact ($14 million) related to storm costs, the total is $85 million, an amount that was not contested by any party. *Id.* at 1294-95. Witness Abernathy then observed that "revenue impacts plus storm costs on the one hand, and the cost savings on the other, are opposite sides of the same coin – but, as shown by my illustration, the reduced revenues and storm impacts ($85 million) outstrip cost savings ($62 million) by a significant amount – approximately $23 million." *Id.* at 1295.

In response to the Public Staff's testimony regarding incremental call center costs, the DEP COVID Panel explained that, although average workload hours decreased during the Commission-ordered disconnection (Q2 and Q3 2020), DEP could not capture the potential savings associated with reduced workload during this timeframe in light of the uncertainty of when DEP would return to normal, making it such that reducing staffing would not have been prudent; and its view that reducing staffing in the short term, only to have to restaff a few months later, would not have been cost-effective. DEP witness Quick clarified that while overall call volume declined in 2021 and 2022, the average handling time per call increased as DEP's customers experienced changing needs following the return to normal. *Id.* at 1276.

Witness Abernathy also testified regarding the various invoices and ledgers DEP provided the Public Staff of its COVID-related expenses and savings. *Id.* at 1284-86. She described in detail the data DEP provided in response to the Public Staff data requests and in support of its COVID cost recovery request. *Id.* Witness Abernathy stated that the Public Staff did not dispute the actual amounts of the costs deferred and requested for recovery. *Id.* at 1286-87. She noted that for bad debt expense, the Public Staff only expressed concerns with DEP's calculation and the reserve percentages used.

Witness Speros provided additional testimony in support of DEP's bad debt expense and calculation. Witness Speros testified to the process that DEP undertook to

develop the reserve percentages, explaining that the reserve percentages are calculated by taking the net charge-off amounts divided by the aged receivable balance utilizing the historical data from 2018 and 2019. *Id.* at 1297. Witness Speros explained that DEP reviews the aging schedules and works with various internal teams to determine if there are any unusual changes or fluctuations in collections and write-offs that could impact the reserve calculation, and that based on these reviews, DEP determines if the balance in the loss reserve is reasonable as stated or if an adjustment is required. Witness Speros also testified that DEP compiles quarterly data on aged receivables, the balance of the loss reserve, and the current write-offs compared to forecast are then summarized and discussed with management. *Id.* at 1298. Witness Speros also clarified how customers on payment plans are treated for purposes of charge-off accounting. *Id.* He stated that customers on payment plans are actively working with DEP and are therefore viewed as having less risk of charging off than the typical delinquent customer. He noted that consistent data is available related to payment plans and a more accurate assessment can be taken by looking at the trends of customer defaults on their payment plans. Witness Speros explained that the percentage is calculated using the dollars defaulted on payment plans divided by total dollars of payment plans. *Id.*

Witness Abernathy testified that DEP has proposed to continue the deferral of bad debt expense until the next rate case. She stated that if the reserve percentages used to calculate bad debt expense do not result in actual charge offs, this will be reflected in future bad debt expense. *Id.* at 1286. Therefore, the continuation of the deferral should resolve any Public Staff concerns about the correct percentages to use. She noted that if the Commission does not approve continuation of the bad debt expense deferral, then test year bad debt expense should be increased by approximately $42 million to reflect a current level of bad debt expense using 2022 actual expense. *Id.* at 1286-87.

Testimony Presented at the Expert Witness Hearing

At the expert witness hearing, Public Staff witnesses Zhang and Boswell responded to questions on cross-examination and from Commissioners about their recommendation to disallow all COVID-related expenses included in DEP's deferral. Witness Boswell testified that part of the reason why the Public Staff removed the expense was because it could not determine what level should be included. Tr. vol. 19, 139. Public Staff witness Boswell stated that the Public Staff struggled to receive information from DEP and that underlying the difference of opinion between the Public Staff and DEP is the respective views on COVID savings. *Id.* Witness Boswell further stated that it is unreasonable to offset COVID-related savings against other costs, such as storm and weather costs, as DEP has proposed. *Id.* at 140. In response to a hypothetical question on deferral approval from Commissioner Duffley, witness Boswell testified that an appropriate amortization period would be around ten or fifteen years, akin to storm recovery, instead of the three years proposed by DEP. *Id.* at 141.

The COVID Panel also responded to questions from Commissioners related to DEP's deferral request. Witness Abernathy began by providing the final amount of the requested deferral in this proceeding – $107 million through DEP's third supplemental

update. Tr. vol. 21, 1307. Witness Speros explained that DEP has a structured and well-documented approach for tracking its COVID-related impacts, and further clarified that DEP's bad debt expense consists of two components: actual charge-offs, and a reserve adjustment based on the level of accounts receivable. *Id.* at 1310-11. Witness Abernathy explained DEP's methodology for the quantification of net lost revenues but reiterates that DEP has not requested recovery for lost revenues, *Id.* at 1316, 1343, and witness Bowman provided testimony related to the costs incurred in order for DEP to continue to operate as an essential service provider. *Id.* at 1319. Witness Bowman explained that 40% of DEP's workforce had to continue work as before, even in light of potential nonpayment due to the disconnection moratorium in place at the time, and that in no instance did DEP stop providing its services. *Id.* at 1319-20. Witness Bowman further testified that this period extended from March of 2020 until August of 2022. *Id.* at 1321. Witness Bowman explained that this continuation of service came at a cost to DEP as it ensured safety protocols were in place and followed and procured adequate protective gear for DEP's employees. *Id.*

Concerning the amortization period of the deferred costs, witness Bowman indicated its preference for a shorter amortization period stating DEP's preference for a three-year amortization but stated that DEP would likely be willing to slightly extend the recovery period. She testified that, if extended, DEP would prefer the amortization period be in a three-year increment, such as six years, to keep in sync with the MYRP. *Id.* at 1327.

Public Staff witness Boswell testified that "the Company meticulously … [accounted for] the costs associated with COVID." Tr., vol. 19, 161. Witness Boswell further testified that, while the Public Staff would have liked to provide the Commission with a recommendation on recovery of COVID costs, "[t]ruthfully … we couldn't determine what level should be put in there." *Id.* at 138. Witness Boswell noted that the Public Staff had issued numerous data requests and participated in several teleconferences with DEP seeking to formulate a recommendation. *Id.* She stated that "…since we couldn't come to a number, we thought it was just wiser to remove [the deferred COVID costs] altogether than to put a range for which that we didn't fully have support for." *Id.*

Witnesses Abernathy and Speros addressed the "savings" issue directly. Witness Speros noted that while costs can be (and were) directly tracked, the negative is not true – "savings" are not directly trackable; rather, they must be discerned through data analysis, namely by comparing actual expenditures with budgeted expenditures to get a sense of what DEP did not spend versus what it thought it would spend. Tr. vol. 21, 1345. He stated that at that point, the analyst can make a judgment based upon the type of expense and whether it is COVID-related. *Id.* Witness Abernathy confirmed that is precisely what DEP did to determine that the employee expense and printing/postage reductions discussed in her testimony, in fact, directly related to the pandemic. *Id.* at 1346. The witnesses maintained there is no reason that the Public Staff could not go through the same exercise, had it chosen to do so. They noted that the Public Staff had the data including "[a]nalysis of comprehensive actuals vs. budget information by O&M for function for 2020 (PS DR 138)" and that data was even supplemented outside of the formal discovery process. DEP Redirect COVID Panel Rebuttal Ex. 1, Tr. Ex. vol. 21. When

asked by Chair Mitchell if the Public Staff used any of this data provided by DEP to estimate COVID savings, witness Abernathy responded, "[n]o, they have not." *Id.* at 1350.

Concerning DEP's request to continue the COVID deferral for bad debt expenses, witness Abernathy testified (and her testimony is uncontradicted) that were the Commission to side with the Public Staff and refuse cost recovery and continued deferral, test year bad debt expense in this case would increase by approximately $42 million, increasing the revenue requirement in this case by that amount, an amount which no party to this proceeding has challenged. *Id.* at 1354-55; Tr. vol. 22, 13. Witness Abernathy testified that the revenue requirement associated with recovery of the deferred costs in this case is $41 million. Tr. vol. 21, 1307. She maintained that, not only is DEP's proposed approach the most reasonable and equitable, it is also the approach that results in the lower revenue requirement in this proceeding.

Further, as it relates to DEP's request for continuation of the COVID deferral, witness Quick explained that part of this request results from the payment plans that DEP offered at the expiration of the disconnection moratorium and the expansion of the Winter Moratorium. Tr. vol. 21, 1328-29. Witness Quick testified that this provided customers with flexibility and support to make disconnection a last resort. *Id.* at 1330. Witness Abernathy explained that this process has resulted in higher arrearages and testifies that DEP accordingly has not seen the completion or lack of completion of all the authorized payment plans, and therefore is unable to calculate an appropriate level of bad debt expense. *Id.*

Discussion and Conclusions

In the Deferral Order, the Commission expressly granted DEP's request that "estimated incremental costs of utility service that are proximately caused by the pandemic may be deferred pending a final determination on cost recovery in a future rate case," and also held that its decision was "without prejudice to the right of any party to take issue with the amount, if any, of the deferred costs to be allowed for ratemaking purposes, if such costs are included in future rate filings." Deferral Order at 13. Typically, the Commission's customary two-prong deferral test is applied in the context of a deferral request such that the nature of the costs and magnitude thereof need not be litigated in the subsequent cost recovery docket. The COVID deferral request was unique in the sense that the costs were unusually speculative, the length of time totally unknown, and the magnitude indefinite, leaving the Commission unable to evaluate the second prong in a meaningful manner in the COVID Deferral Docket. In its discretion, the Commission may in this proceeding undertake an analysis of the magnitude of the deferred COVID expenses that are now known and measurable, if the Commission determines such analysis is necessary in reaching its conclusion regarding cost recovery of COVID-related costs. The three main factors that the Commission generally finds relevant in its analysis of the second prong are: (1) the amount of the deferred costs; (2) DEP's earnings during the analogous timeframe; and (3) fairness and equity.

In prior deferral orders, the Commission has noted that it does not apply the two-prong test in a vacuum. Rather, the Commission considers all of the pertinent factors involved on a case-by-case basis and weighs the equities to arrive at a decision that is fair to the utility and its ratepayers, and that serves the public interest. The Commission may analyze the merits of deferral using not only the well-established two-prong test but also considering the totality of the underlying facts, circumstances, and equities of this case. In the case of the incremental COVID-related costs, the Commission determines that the two-prong test was met in that these costs are extraordinary in nature and, absent deferral, would have a material impact on the utility's financial condition. The Commission gives significant weight to DEP's calculation in this proceeding that the $105.0 million in deferred costs amount as of DEP's second supplemental filing would have a 124 basis point impact on earnings, excluding any impacts on lost revenues.

In this proceeding, the Public Staff noted that DEP has consistently achieved earnings in excess of its authorized ROE since before the COVID pandemic and maintained that DEP's earnings are a relevant factor for consideration in the Commission's decision concerning cost recovery. The Commission acknowledges that historically in assessing the appropriateness of cost-deferral requests, the Commission has based its decision, in large measure, on the impact that the costs would have on the level of earnings currently being achieved by DEP. The impact on earnings, typically, has been measured and assessed in terms of ROE, considered in conjunction with: 1) the ROEs realized and reported to the Commission in DEP's recent quarterly ES-1 reports, particularly the ROE reflected in DEP's most recent report; and 2) DEP's currently authorized ROE. In this proceeding, the Commission finds that the COVID pandemic was an unprecedented event – truly exceptional – much more so than unusually severe weather and other events for which costs have been allowed to be deferred in the past. In determining fairness and equity between customers and shareholders in this circumstance, the Commission must evaluate the totality of the situation.

The Commission recalls that during the state of emergency government officials were taking all necessary steps to slow the spread of the coronavirus by requiring people to social distance and stay at home to the greatest extent possible. The health and safety of North Carolina communities were affected by the efforts of all residents to stay home and socially distance to slow the spread of the coronavirus. Governmental actions were also implemented to help prevent hospitals from being overwhelmed with patients and to preserve human life. The seriousness of the circumstance was unprecedented. The Commission recognizes that it was crucial for DEP, as a provider of an essential service, to fulfill its obligation to its customers to continue operations 24 hours a day, seven days a week despite the pandemic. This vital requirement for DEP to continue to provide its customers essential electric utility service during this unprecedented event cannot be overemphasized. The Commission recognizes that DEP met its obligation to the Commission and the citizens of North Carolina. The Commission recognizes that for DEP to provide electric utility service to the citizens of North Carolina during the pandemic necessitated certain DEP employees to perform their job duties in the same manner as prior to the declaration of the state of emergency. As a result, many of DEP's employees

were not allowed the option to work from home to protect the health and safety of themselves and their families.

Government officials, including this Commission, sought to aid North Carolina citizens amidst a turbulent and challenging economic environment by issuing a state of emergency and various mandates and moratoriums. During the height of the turmoil caused by the pandemic, customers benefitted from the governmental mandates to waive customer fees and discontinue disconnections for non-payment. The pandemic lasted much longer than anyone anticipated. Businesses, families, and individuals benefitted from these mandates, particularly households that were struggling with financial issues resulting from the pandemic. Further, DEP, at this Commission's direction, provided customers with new, more favorable payment options and worked to connect eligible customers with available financial assistance from new and existing federal and state programs.

In reaching its decision concerning cost recovery of the incremental COVID-related expenses, the Commission sought to balance fairness and equity between customers and shareholders when: 1) determining the appropriate size or amount of the deferral for cost recovery in this proceeding; 2) applying the COVID-related savings; 3) determining whether a return should be allowed on the deferred costs during the deferral period and on the unamortized balance during the amortization period; 4) selecting the amortization period for cost recovery; and 5) deciding the timing of when amortization should begin.

In its examination of the deferred COVID-related costs for which to allow cost recovery, the Commission gives significant weight to the fact that the Public Staff, which extensively audited the deferred costs, did not find any of the costs to be unreasonable in amount and did not find that any of the costs were unrelated to the COVID-19 pandemic. As it did in the Deferral Docket, the Public Staff argues that COVID costs should be offset with COVID savings, and that, in its view, DEP has not adequately accounted for savings.

After careful consideration, the Commission concludes based upon the evidence presented that recovery in rates of DEP's deferred COVID-related costs pertaining to customer fees waived, bad debt expense, and employee safety related costs, are just and reasonable and should be approved. The Commission determines that it is appropriate to reduce these allowed costs by certain COVID-related expense savings for employee travel expenses, printing and postage costs, DEP's filed ERCs, and the carrying cost benefit of the delayed payment of the employer portion of social security tax. The Commission concludes that it is not appropriate to recover the carrying costs accrued during the deferral period or a return on the unamortized balance during the amortization period. Further, the Commission determines a six-year amortization beginning when rates become effective for this proceeding is appropriate. The Commission sets forth its reasons for these conclusions below.

Regarding the amount of costs deferred, DEP witness Abernathy testified that as of the filing of the Third Supplemental Testimony filed on April 18, 2023, the projected balance of deferred incremental COVID-19 costs as of the date rates would go in effect increased to

approximately $107 million, mainly because of an increase in the amount of bad debt expense that occurred in connection with the expiration in March 2023 of 12-month repayment plans DEP automatically enrolled customers into as of the time (March 2022) when the extended winter moratorium on disconnection finally ended. The Commission acknowledges that no party has challenged the expenses for which DEP now seeks recovery pursuant to the Deferral Order were COVID-related expenses. Instead, the fundamental disagreements between DEP and the Public Staff are: (1) whether certain deferred COVID expenses are appropriate for recovery from ratepayers; (2) whether the deferred COVID expenses should be offset by certain savings, benefits, credits, and overearnings; and (3) whether a return on the deferred costs during the deferral period and on the unamortized balance during the amortization period should be allowed.

The Commission notes that as indicated in the chart above provided by witness Abernathy, over 90% of the deferred costs were incurred from waived customer fees and bad debt expense. The Commission concludes that these two costs resulted directly from governmental action, including mandates from the Commission, and are appropriate for recovery from customers. Specifically, at the onset of the COVID-19 pandemic the Governor issued a proclamation of a state of emergency (Executive Order No. 116), and subsequent orders of the Governor and of the Commission imposed a moratorium upon DEP's ability to disconnect customers for nonpayment and required waiver of customer fees ordinarily imposed in connection with nonpayment, such as late fees, reconnection fees, and return check charges. As a consequence of these governmental actions, DEP was unable to use its customary tools to timely collect payments from customers. DEP's ability to charge certain customer fees such as late fees, reconnection fees, and returned check charges encourage customers to pay their monthly bills. Disconnection of electric service is a strong incentive for the customers to pay their bills timely. The DEP COVID Panel testified that the moratorium on disconnections and the suspension of late fees had an adverse impact on the level of bad debt expense in that DEP realized an increase in the number of past due accounts that ultimately caused a significant increase in bad debt expense.

In this proceeding DEP seeks to recover only the difference between the level of bad debt expense currently in rates and the amount of bad debt expense above that level resulting from actions taken during the pandemic. The Commission acknowledges that denial of the recovery of deferred waived customer fees and bad debt expense would deny DEP recovery of costs incurred for complying with Executive and Commission Orders. DEP was expected to continue to provide normal, uninterrupted electric service 24 hours per day, seven days a week, to all customers during this unprecedented event. Moreover, DEP was expected to continue to provide service to its customers who were not paying for such service for an extended period of time. The Commission concludes that these costs are reasonable for recovery from customers.

With respect to employee safety related costs, the Commission acknowledges that DEP incurred costs to provide its employees with the appropriate personal protective equipment to facilitate the continuation of work for customers in a safe manner. Additionally, DEP incurred incremental costs associated with cleaning supplies, health

care, as well as testing and temperature checks. As previously noted, to provide essential electric service, many of DEP's employees were not allowed the option to work from home. DEP witnesses testified that more than 40% of DEP's workforce had to show up, in person, at work, at power plants and other facilities, or to repair damage following storms. The Commission concludes that those employees had to be furnished with protective gear, cleaning/sanitizing supplies, and COVID testing services and nursing case management. Thus, the Commission concludes that these costs are reasonable and prudent costs to recover from customers.

Regarding the costs of remote work, in order to facilitate employees working remotely to protect their health and safety during the pandemic, DEP incurred incremental costs associated with expanded conference line capacity, increased network bandwidth, other required information technology improvements, expanded video conferencing licenses, and increased company cellular telephone and data usage. The Commission recognizes that many other businesses and state agencies in North Carolina were able to shift to fully or nearly full remote work to respond to the Governor's state of emergency and also incurred similar incremental costs to accommodate employees working remotely. The Commission notes that in the post-state of emergency work environment, remote work offerings continue either fully or on a hybrid basis for many businesses, state agencies, and utilities, including DEP. The Commission determines that although the pandemic may have initiated this category of costs, these costs are now largely ongoing in nature and not specific to the pandemic. Moreover, DEP has not offset the deferred costs of remote work with the associated decreases in office expenses such as utilities, office supplies, and other miscellaneous expenses related to employees working from the office. Thus, the Commission concludes that it would not be appropriate to recover the deferred costs of remote work from customers.

DEP provided certain eligible employees a one-time cash payment of $1,500 to help with unplanned expenses associated with COVID-19. DEP testified that the stipends were appropriate to support employees in providing service to customers and to avoid turnover and should be allowed as reasonable and prudent costs. The COVID Panel contended that DEP did not require expense verification associated with the employee stipends to avoid the extra administrative cost of reviewing receipts and validating usage by the employees that received the stipend. The Commission concludes that the one-time $1,500 stipends provided voluntarily by DEP to certain hourly employees should be considered voluntary goodwill and should not be recovered from customers. Usage of the stipends was not verified by DEP and that employees were free to spend the funds as they pleased, without oversight, and thus the Commission determines they should be excluded from cost recovery of deferred COVID expenses.

DEP witness Jiggetts testified that the other category of deferred costs includes overtime to implement COVID-19 guidelines to ensure employee safety and increased costs due to expected increased call volume at call centers when normal billing practices resume. Public Staff witnesses Boswell and Zhang contended that expenses associated with call center overtime should not be included in the ongoing COVID deferral given that the amount sought by DEP for call center overtime was not above the amounts already

included in DEP's cost of service. The Commission is persuaded that, because the amount sought by DEP for call center overtime was not above the amount already included in DEP's cost of service, these costs should not be recovered from customers.

Regarding COVID-related cost savings, the COVID Panel contends that the Deferral Order required only that DEP track the costs being deferred, but that nonetheless DEP was required to track and report COVID savings (specifically, reduced employee expenses such as reductions or elimination of travel and expenses associated with normal operations while employees were required to work remotely and adhere to travel restrictions, and reduced printing and postage costs) and NLRs on a South Carolina retail basis for 2020 and therefore did, and provided to the Public Staff, the incremental COVID savings and NLRs at a system level to which it applied allocation factors to derive the South Carolina retail amounts. According to the COVID Panel, DEP's COVID savings were largely realized in 2020 in the amount of approximately $4.5 million on a North Carolina retail basis, while DEP estimated the NLRs related to reduced load and demand in 2020 to have been approximately $28 million on a North Carolina retail basis, thereby more than offsetting the savings reductions that the Public Staff suggests.

Although not presented in filed testimony, in its proposed order the Public Staff maintained that a portion of the O&M savings DEP experienced in 2020 and 2021 – which includes any savings experienced by DEP related to remote work, and reduced expenses in employee travel, printing, and postage – should offset the deferred COVID costs DEP is now seeking to recover. The Public Staff contended that, with few exceptions, DEP stated it did not track how the O&M savings were derived, thus, there is no amount that the Public Staff could definitively identify as strictly COVID-related savings. In light of this, the Public Staff recommended that 50% of DEP's total non-fuel O&M savings in 2020 and 2021 should be offset against the deferred COVID costs sought for recovery. The Commission notes that in its proposed order, the Public Staff also recommended disallowance of the employee stipends and the increased call center costs but did not specifically object to cost recovery of any other category of DEP's deferred COVID-related costs.

The Commission acknowledges that DEP is not requesting rate recovery of the NLRs related to the COVID pandemic. Witness Bateman testified that DEP made a conscious decision not to request deferral of NLRs in the COVID Docket. Witness Bateman further testified that DEP did what it always does when faced with the prospect of lower than budget revenues, DEP absorbs revenue impacts through O&M savings. Witness Bowman explained that when faced with the prospect of revenue loss, DEP as a routine part of its business and in keeping with its focus on managing O&M cost for the benefit of customers, identifies and implements a suite of cost mitigation measures. Witness Abernathy testified that further complicating the picture in 2020, the prospect of revenue loss arose not only from the pandemic but also from mild weather. She noted that DEP responded to twin threats to its revenue stream, both the pandemic and mild weather, by instituting cost efficiency measures, which she described in detail. She testified that none of these "belt tightening measures" were included in the deferred costs. Witness Abernathy maintained that DEP did everything that it could to reduce costs and,

as a result, avoided the need to request a deferral of the NLRs. However, DEP was not able to offset both the incremental costs due to COVID-19, and the other unfavorable impacts in 2020, including the NLRs due to COVID. The end result is that deferral of incremental COVID-19 costs was required and requested, and the Commission gave its approval to that deferral. Witness Abernathy contends that none of the cost savings measures discussed above have been – or should be – used to offset the COVID-19 related incremental costs.

When asked by the Public Staff to identify the COVID-related savings, witness Abernathy testified that two categories of savings were identified: 1) reduced employee expense related to reduction in or elimination of travel, and 2) reduced printing and postage costs as a result of the disconnect moratoriums ordered by the Commission. The Commission concludes that these cost savings identified by DEP which were directly attributable to the pandemic should offset the amount of deferred COVID-related expenses. DEP witness Speros noted that while COVID-related costs can be and were directly tracked, the negative is not true – "savings" are not directly trackable; rather, they must be discerned through data analysis, namely by comparing actual expenditures with budgeted expenditures to get a sense of what DEP did not spend versus what it thought it would spend. He stated that the analyst can make a judgment based upon the type of expense as whether it COVID-related. Witness Abernathy confirmed that is precisely what DEP did to determine that the employee expense and printing/postage reductions were, in fact, directly related to the pandemic.

The Commission determines that the issue of COVID-related cost savings is intertwined with the issue cost savings resulting from the mitigation measures taken by DEP to address NLR. Furthermore, various events occurring in 2020 are entwined in the analysis - COVID, mild weather, and storm restoration costs. On the one hand, in its proposed order the Public Staff indicated there was no amount that the Public Staff could definitively identify as strictly COVID-related savings; thus, the Public Staff recommended that 50% of DEP's total non-fuel O&M savings in 2020 and 2021 should be offset against the deferred COVID costs sought for recovery. On the other hand, DEP, through witness Abernathy's testimony, maintained that none of DEP's cost saving measures to mitigate NLRs should be used to offset the incremental COVID-related costs. Witness Abernathy also maintained that savings related to the federal government assistance for which DEP filed ERCs and was granted a carrying cost benefit related to the delayed payment of the employer portion of social security tax. The Commission concludes that these measures taken by the federal government to assist companies and employers in weathering the impacts of the pandemic should inure to the benefit of customers. To balance the fairness and equity between customers and shareholders related to the COVID-19 pandemic and, in part, because the amount of COVID-related savings cannot be definitively identified, the Commission did not approve all deferred COVID-related expenses for cost recovery from customers. The Commission notes DEP's position on savings and the difficulties associated with calculating savings that are directly attributable to the pandemic. However, the Commission determines that the two types of savings identified by witness Abernathy are directly related to the pandemic and that the measures taken by the federal government to assist companies and employers during the pandemic which provided

benefits to DEP, directly relate to the pandemic. For these reasons, the Commission concludes that these costs should be netted against deferred COVID-related costs. In reaching this conclusion, the Commission gives weight to the testimony of witness Abernathy that expense savings resulting from DEP's normal cost mitigation measures to offset revenue shortfalls related to mild weather and in this case, the pandemic, should not be used to offset COVID-related expenses.

The Commission declines to approve DEP's request to recover approximately $12 million in accrued carrying costs on the deferred costs or to authorize a return on the unamortized balance of the COVID costs during the amortization period. In reaching this decision, the Commission is conscious of the fairness and equity factors inherently at play in considering how to appropriately balance the difficulties experienced by both the utility and ratepayers throughout the pandemic. DEP contends that inasmuch as the deferred costs are by definition not already in rates and were fronted by DEP's investors, the costs properly bear a return at DEP's weighted average cost of capital so as to ensure that DEP and its investors are made whole. The Public Staff recommends denial of any return on the allowed deferred expenses stating that interest has already been accounted for in the $27 million late payment fees of the deferred expenses at issue in this proceeding, and to allow an additional return would unfairly allow DEP to collect interest upon interest.

Taking into consideration the hardships caused by the pandemic on the residents and businesses in North Carolina, DEP's earnings reported in its E.S.-1 Report during the deferral period which were at or above the utility's authorized rate of return, and the totality of the hardships suffered by customers during the pandemic, the Commission concludes that the approximately $12 million included in DEP's request related to accrued carrying costs on the deferred costs or a return on the unamortized balance during the amortization period should not be recovered from customers through rates.

The Commission concludes that it is appropriate that cost recovery for the approved deferred COVID-related costs occur over a six-year amortization period. Due to the material amount of COVID-related costs approved for recovery, the Commission finds that the three-year amortization period requested by DEP would be burdensome for customers. The 12-year amortization period advocated by the Public Staff in its proposed order is unreasonably long in light of the Commission's decision herein to not allow carrying charges on the deferred costs. The Commission has customarily used a five-year amortization period for recovery of costs from customers for extraordinary events like storms. However, at the expert witness hearing, the COVID Panel stated DEP's preference that the amortization period be in a three-year increment, such as six years, to keep in sync with the MYRP. Thus, the Commission determines that a six-year amortization period reasonably balances the impacts to both DEP's customers and its shareholders.

The Commission determines that amortization of the deferred COVID-related costs should begin upon the effective date of new rates in this proceeding.

Regarding DEP's request to continue its deferral for incremental bad debt expense, the Commission determines that since DEP is still incurring incremental bad debt expense, it is appropriate for DEP to continue to defer those costs incurred after March 31, 2023. The Commission concludes that DEP's request to continue the deferral of the incremental bad debt, for future recovery, is just and reasonable, and should be approved. The Commission acknowledges the positions taken by the Public Staff in its proposed order related to this issue and agrees with the Public Staff's recommendation that any payments associated with the deferred bad debts should be credited on a monthly basis through the next general rate case but declines to accept the Public Staff's other recommendations related to call center overtime costs or an ongoing overearnings analysis during the deferral period. Thus, the Commission concludes that DEP should credit on a monthly basis through the next general rate case any payments associated with the deferred bad debts.

Finally, the Commission notes that its decision on deferral of the COVID-related costs is based on the particular facts of this case, and in particular, the unprecedented circumstances related to the pandemic, and should not be cited or relied on as precedent for future cost deferral decisions. The Commission evaluated the totality of the pandemic, taking into consideration the governmental mandates which removed DEP's tools to control bad debt expense, the necessity for DEP to provide uninterrupted electric service during the duration of the pandemic – even when many customers were not paying their bills, the benefit to customers and North Carolina as a whole of the governmental mandates, and DEP's financial standing as reported in its quarterly E.S.-1 Reports to the Commission for the duration of the deferral period. Considering all these factors and the entire evidence of record, the Commission concludes that its decision set forth herein is the most reasonable, fair, and equitable outcome for both customers and shareholders with respect to the COVID-19 pandemic.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 57

Inflation Adjustment

The evidence supporting this finding of fact is found in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts and Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Summary of Evidence

DEP Direct and Supplemental Testimony

DEP, through witness Jiggetts' direct testimony and exhibits, adjusted its annual non-labor and non-fuel O&M costs to reflect the increase in costs during the test period that occurred due to inflation. *See* Tr. vol. 13, 185. In supplemental direct testimony, witness Jiggetts testified that this inflation adjustment was updated to reflect inflation factors through December 31, 2022, and to remove the impact of the gains/losses on the sale of by-products. *Id.* at 222-23. This inflation adjustment factor was subsequently

updated in Jiggetts' second and third supplemental direct testimony, *Id.* at 232, 243, and finally in Settlement Testimony to arrive at a rate of 12.13%. Jiggetts Partial Settlement Ex. 4 at 109, Tr. Ex. vol. 14.

The Public Staff Testimony

Public Staff witnesses Zhang and Boswell recommend that the Commission adjust DEP's inflation factor to reflect a five-year average inflation rate through December 31, 2022. Tr. vol. 19, 44. Witnesses Zhang and Boswell further recommend that the inflation adjustment be modified to reflect the Public Staff's recommended adjustments removing aviation expenses, Board of Directors expenses, uncollectibles, and sponsorships and donations. *Id*. In supplemental testimony, witnesses Zhang and Boswell applied their recommended inflation adjustment to actuals through February 2023 to reflect the 61-month average recommended by the Public Staff. *Id.* at 90. Witnesses Zhang and Boswell testified that the increasing inflation rates seen in 2021 and early 2022 have already begun to decrease and that DEP's 2021 expenses already reflect some portions of the increase in costs due to inflation. *Id.* at 44-45. They further testified that the Public Staff does not find it appropriate to calculate ongoing rates for a minimum of the next three years based on years in which inflation was abnormally high. *Id.* at 45.

DEP Rebuttal Testimony

In rebuttal, DEP witness Jiggetts opposed the Public Staff's recommended adjustment. Tr. vol. 23, 93-97. Jiggetts testified that DEP's proposal does not project inflation of O&M expenses, but instead accounts for the impacts of inflation that have already been incurred from the test period to the end of the update period. *Id.* at 94. Witness Jiggetts further testified to DEP's methodology for calculating an inflation factor, stating that it has not changed from previous rate cases. *Id.* Witness Jiggetts testified that the Public Staff's assertion that any non-payroll O&M expenses updated beyond December 2021 would include impacts related to inflation is incorrect, and she explained that any O&M expenses that are updated through pro forma adjustments are excluded from the inflation adjustment. *Id.* at 94-95. Witness Jiggetts cited data from the U.S. Bureau of Labor Statistics that shows a continual upward trend for all inflation metrics. *Id.* at 96. Further, witness Jiggetts testified that while DEP disagrees with the Public Staff's adjustments removing certain expenses related to aviation, sponsorships, donations, lobbying, and Board of Directors expenses, DEP agrees that it would be appropriate to adjust the total O&M subject to inflation for that amount, to the extent that there are adjustments made to those expenses. *Id.* at 97.

Testimony Presented at the Expert Witness Hearing

At the hearing, witness Jiggetts testified to DEP's recommended inflation rate factor of 12.13%. Tr. vol. 13, 302. Witness Jiggetts explained that DEP uses a 13-month average to calculate its inflation factor, consistent with its methodology in the previous rate case. *Id.* at 302-03. She further explained that, in calculating the inflation factor, DEP is looking at the actual level of inflation, as reported by the U.S. Bureau of Labor Statistics,

through the March 31, 2023 cutoff date. *Id.* at 302. She testified that DEP compares that level of inflation to the costs actually incurred during the test year by looking at the 13-month average of the Bureau of Labor Statistics' data. *Id.* at 302-03. Using this approach, witness Jiggetts explained that inflation has increased to 12.13% through the March 31, 2023, cutoff period. *Id.*

Witness Jiggetts clarified that the test year used in the adjustment is historical, rather than prospective, and that the purpose of the adjustment is to adjust test year expenses to account for inflation as of the March 31 cutoff period. *Id.* at 304. Witness Jiggetts explained that DEP does not project inflation rates or factors. *Id.* at 304. Instead, the test year expenses are adjusted for known and measurable changes through the March 31 cutoff period. *Id.* at 303.

Public Staff witness Zhang testified that the Public Staff calculated its recommended inflation adjustment by averaging the inflation rate over the 61-month period from January 2018 through January 2023. Tr. vol. 19, 116-17. Witness Zhang further testified that averaging the inflation rate over that 61-month period with the average inflation of the consumer producer price index's published inflation resulted in a 61-month average inflation factor of 4.31%. *Id.* at 117. In response to cross examination by DEP, witness Boswell testified that she could not state for certain if the Public Staff's methodology had previously been used in any electric utility rate case. *Id.* at 128.

Discussion and Conclusions

The Commission concludes, based upon the evidence presented, that the rate factor adjustment proposed by DEP is just and reasonable. The Commission declines to adopt the 61-month average method advocated by the Public Staff and notes that per DEP's Late-Filed Exhibit No. 13, the Public Staff has previously proposed the same method that DEP employed in this proceeding. The Commission determines that the adjustment proposed by DEP, at 12.13%, captures actual inflation during the test period updated through March 31, 2023, in substantially the same manner that DEP has historically employed.

Specifically, the inflation adjustment (Adjustment No. NC2110 in witness Jiggetts' schedules) annualizes test period O&M expenses, excluding fuel, purchased power, and labor and benefit costs to reflect the change in test period costs through the March 31, 2023 cutoff date by an actually-experienced inflation factor. The adjustment captures actual inflation during this period in the same manner used in at least DEP's last seven general rate cases. DEP Late-Filed Ex. No. 13. As witness Jiggetts testified, DEP has proposed and the Commission has approved rates that were calculated using the method of determining the inflation adjustment used by DEP in this proceeding for many years, in all kinds of inflationary environments. While the Commission recognizes that, as the Public Staff points out, the period of time during which the updated test year occurred was coincident with unprecedented times, including the pandemic, the Commission is concerned that a departure from historical practice on this issue is not warranted, as adjusting for "known and measurable changes" is consistent with N.C.G.S. § 62-133(c)

and produces the just and reasonable result of putting DEP in a position of recovering its costs, and is fair to DEP and to customers regardless of the inflationary environment.

Upon consideration of all the evidence in this proceeding, the Commission concludes that DEP's proposed inflation adjustment to test year non-fuel and non-labor O&M costs is consistent with past practice, consistent with statutory law, derived using a method that is fair to customers and to the utility regardless of the inflationary environment, and is approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 58-60

Rate Case Expense

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the testimony and exhibits of DEP witnesses Jiggetts and Bateman; Public Staff witnesses Zhang and Boswell, and the Public Staff's cross exhibits of witness Jiggetts; and the entire record in this proceeding.

Witness Jiggetts testified that, in the current proceeding, DEP has included adjustment NC5020 related to rate case costs, amortizes over a three-year period the incremental rate case costs incurred and projected to be incurred for this docket, as well as costs incurred after the cut-off in the last rate case which have not yet been brought forth for recovery. Her testimony explained that over amortizations associated with rate case costs approved in Docket Nos. E-2, Subs 1023 and 1142 and severance costs approved in the 2019 Rate Case were used to offset the amount requested for recovery in this case. Tr. vol. 13, 176, 194.

With respect to costs associated with the 2019 Rate Case, witness Jiggetts explained that in the first partial settlement in the 2019 Rate Case (2019 First Partial Settlement), entered into by DEP and the Public Staff on June 20, 2020, DEP and the Public Staff settled on an agreed amount of rate case expense that would be recovered from customers. Tr. vol. 13, 332. She explained that the amount of rate case expense was estimated, at that time, to be $3.5 million, which represented the sum of actual expense incurred through February 2020 and estimated to be incurred through August 2020. Tr. vol. 13, 312. Witness Jiggetts testified that the projection of costs through August 2020 was based upon past, normal experience that DEP would have had with a rate case proceeding.

In response to a question from Commissioner Duffley, witness Jiggetts testified that DEP seeks to recover rate case costs in this case which exceed those agreed to in the 2019 First Partial Settlement with respect to rate case expense related to the instant proceeding, Witness Jiggetts updated adjustment NC5020 in her supplemental direct testimony and third supplemental direct testimony to reflect actual rate case expense amounts incurred by DEP. *Id.* at 224, 247.

Witness Jiggetts testified that over-amortizations associated with rate case expenses approved in Subs 1023 and 1142 and severance costs approved in the 2019 Rate Case were used to offset the amount requested for recovery in this case. Tr. vol. 13, 194. She testified that DEP requests that the remaining balance to be amortized over the three-year period. Tr. vol. 23, 78.

Public Staff witnesses Zhang and Boswell explained that they removed: 1) DEP's adjustment to include additional rate case expenses from the 2019 Rate Case that exceed the amount agreed to in the 2019 First Partial Settlement 2) the adjustment to include the unamortized portion of rate case expense in rate base; and 3) DEP's inclusion of over-amortized regulatory assets to offset rate case expense. Regarding the additional costs from the 2019 Rate Case, witnesses Zhang and Boswell testified that the 2019 First Partial Settlement reflected an agreed-upon amount for 2019 Rate Case expenses, and that this amount was ultimately incorporated into the revenue requirement approved by the 2019 Rate Case. As such, the Public Staff asserted that it is inappropriate to include 2019 Rate Case costs beyond those included in the Commission-approved revenue requirement from a general rate case that has been closed, and in which DEP did not request that additional costs be considered before the Commission issued its final order. Tr. vol. 19, 56-57.

Regarding DEP's adjustment to include the unamortized balance of rate case expense in rate base, witnesses Zhang and Boswell testified that the amortization of rate case expense should reflect a normalization of the costs associated with the filing of a rate case, based on an average of the number of years between rate case filings. In this case, witnesses Zhang and Boswell stated that rate case expense does not rise to the level of being extraordinary in nature and, as such, does not require rate base treatment. As with other over-amortizations in this proceeding, witnesses Zhang and Boswell asserted that the over-amortized amounts from the rate case expense and severance costs should be flowed back to ratepayers as a one-year rider and not used to offset other amounts. Tr. vol. 19, 57-58.

In her rebuttal testimony, witness Jiggetts asserted that DEP is not precluded from collecting additional amounts incurred from the 2019 Rate Case based on the 2019 First Partial Settlement. In her view, the 2019 First Partial Settlement does not contain any language capping rate case costs at a maximum amount or prohibiting DEP from asking for additional reasonably and prudently incurred actual expenses in a future rate case. While the amounts agreed to in the 2019 First Partial Settlement were based upon information available at the time the agreement was reached, witness Jiggetts stated that DEP's costs were ultimately higher as the proceedings for that case were delayed and extended, for reasons which could not have been foreseen, and that the Public Staff has made no assertion or forecasted any evidence showing that the additional 2019 Rate Case expenses were not reasonably and prudently incurred. Tr. vol. 23, 79-81.

Rejecting the Public Staff's recommendation that the unamortized rate case costs for this proceeding be removed from rate base, witness Jiggetts explained that DEP's investors have advanced the funds to cover these reasonably and prudently incurred

utility costs and, as such, DEP should be allowed to earn a return on this asset to reflect the earnings expected from its investors during the amortization period. Tr. vol. 23, 81-82.

At the expert witness hearing, witness Jiggetts testified that, to the best of her knowledge, DEP did not provide updates of its 2019 Rate Case expenses through May 2020 as the second settlement would have allowed, and that she was not aware of DEP's having requested to recover these amounts during the 2019 Rate Case expert witness hearing or at any point prior to the filing of this proceeding. Tr. vol. 13, 311-18.

Although not presented in prefiled testimony, in is proposed order, the Public Staff provided additional context concerning various events that occurred during the 2019 Rate Case related to the issue of rate case expense. On June 2, 2020, DEP and the Public Staff filed the First Settlement, in which DEP and the Public Staff agreed that certain rate case expenses as set forth in DEP's rebuttal testimony could be recovered (not in rate base) and that these expenses would be amortized over a five-year period. In DEP witness Kim Smith's testimony supporting the 2019 First Partial Settlement, she describes the settled issues (including rate case expense) as "resolve[d] . . . without the necessity of contentious litigation." 2019 Rate Case, Tr. vol. 14, 260. On July 31, 2020, DEP and the Public Staff filed the second partial settlement, in which the two parties agreed that DEP's updates covering expenses through May 31, 2020 (filed on July 2, 2020), could be included for recovery (pending and subject to the Public Staff's audit thereof), up to 75% of the difference (should the difference result in an increase in the revenue requirement) between DEP's February 2020 costs and May 2020 updates in recognition of the uncertainty regarding the effects of COVID. However, in its July 2, 2020 filing, which updated expenses through May 2020, DEP did not seek recovery of any additional rate case expenses. In addition, the Public Staff notes that the expert witness hearing for the 2019 Rate Case took place in August 2020, but the issue of recovery of 2019 Rate Case expense beyond that provided for in DEP's rebuttal testimony does not appear to have been raised to the Commission during the hearing, in DEP's proposed order, or in any other form during the pendency of the 2019 Rate Case.

According to the Public Staff, DEP had a reasonable opportunity in the 2019 Rate Case to come forth with additional rate case expenses, and it failed to do so. If DEP believed there were 2019 Rate Case expenses outside the confines of the 2019 Settlement Agreements, DEP should have raised this issue at the 2019 Rate Case expert witness hearing and sought the Commission's guidance on how to preserve the issue, but it failed to do so. The Public Staff asserts that just because DEP's 2019 Rate Case expenses were ultimately higher than expected due to COVID does not mean that the entire category of 2019 Rate Case expenses were not encompassed in the settlement agreements. Instead, this was an aspect of settlement that DEP did not foresee. However, the Public Staff asserts that the fact that DEP did not foresee the impact of its agreements is not justification to depart from the terms therein or deprive customers of the benefit of the Public Staff's bargain.

In their second supplemental testimony filed on June 27, 2023, Public Staff witnesses Zhang and Boswell updated rate case expenses to reflect the actual rate case expense incurred through March 31, 2023, as reflected in DEP's third supplemental filing.

Discussion and Conclusions

The Commission must decide on three issues relating to rate case expense: (1) recovery of rate case expense from DEP's 2019 Rate Case, as well as the recovery of rate case expense from the current proceeding; (2) whether rate case expense should be reflected in the rate base; and (3) the amortization period over which the expense should be recovered. As discussed below the Commission concludes that (1) DEP's request to recover costs incurred from the 2019 Rate Case which are above and beyond those provided for in the 2019 Settlement Agreements is approved; (2) the unamortized balance of rate case expense should not be reflected in the rate base; and (3) the amortization period over which the rate case expense should be recovered is three years. The issue regarding whether over-amortizations associated with rate case costs approved in Sub 1023 and severance costs approved in the 2019 Rate Case should be used to offset the rate case expense in this proceeding is discussed in other portions of this Order.

The Commission notes that 2019 First Partial Settlement reflected a settlement on the sum of actual rate case expense incurred through February 2020 plus expenses estimated to be incurred through August 2020. The Commission also notes, as DEP witness Jiggetts testified, that DEP did not update its rate case expenses through May 2020, as the second partial settlement in the 2019 Rate Case allowed. However, the Commission also notes the unusual, perhaps unprecedented, trajectory of the 2019 Rate Case. Specifically, the first partial settlement was entered into on June 2, 2020, and the second settlement was entered into on July 31, 2020. The consolidated hearing for DEC and DEP was held in late August 2020. The separate hearing for DEP was held in late September to early October 2020. Between the consolidated hearing and the individual hearing, DEP worked to put interim rates into effect and notified customers of same. On December 11, 2020, the Supreme Court issued its order in *State ex rel. Utils. Comm'n v. Stein*, 375 N.C. 870, 851 S.E.2d 237 (Dec. 11, 2020), effectively remanding the issue of cost recovery for coal combustion residuals (CCRs) back to the Commission. Subsequent to issuance of that decision, DEP engaged in settlement discussions related to CCR cost recovery. On January 25, 2021, the Coal Combustion Residuals Settlement Agreement (CCR Agreement), to which DEP and the Public Staff were parties, was filed in the 2019 Rate Case docket. On February 12, 2021, the Commission issued an order in the 2019 Rate Case docket re-opening the record to accept into evidence supporting testimony filed by DEP and the Public Staff. On February 17, 2021, the Commission issued an order requiring DEP to respond to certain questions from the Commission regarding the CCR Agreement. The final order in the 2019 Rate Case was issued by the Commission on April 16, 2021. Subsequent to the issuance of the order, DEP worked to establish rates in compliance with the Commission's order, provide notice to its customers of new rates and put those rates into effect on June 1, 2021. The 2019 Rate Case, initiated by application

filed in August 2019 made by DEP, culminated with rates' taking effect on June 1, 2021. This timing was impacted by events outside of DEP's control, namely the pandemic and the issuance of the Stein order by the North Carolina Supreme Court. As summarized by DEP witness Jiggetts:

> The actual hearings, the consolidated hearings, I believe, happened at the end of August of 2020. We had interim rates that went into effect in September of 2020. The individual hearing for DEP happened, I believe, late September, early October of 2020. The CCR settlement was essentially reached in January of 2021. The Order in that case came out in April of 2021. And then new rates went into effect in June of 2021.
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> During that time frame, obviously, we had additional discovery that required, you know, questions and responses. We had the prep and the times for the hearings. So all of that, kind of, bled into the costs being more than what we initially estimated at the time of settlement in June of 2020.

Tr. vol. 23, 118.

The Commission understands and respects the Public Staff's strongly held position that the settlement agreements entered into during the rate case should govern and that DEP should be held to the terms of these agreements in order for customers to receive the benefit of the Public Staff's bargain. In general, the Commission agrees with the Public Staff that parties must be held to their agreements made in settlement, particularly in the interest of encouraging future settlements. Nevertheless, the Commission concludes that it would be unreasonable to deny DEP recovery of expenses incurred in the context of the 2019 Rate Case that were not reflected in the 2019 First Partial Settlement The Public Staff asserts that DEP could have raised the issue rate case expense during the August 2020 expert witness hearing, but it is not clear to the Commission that DEP could have reasonably anticipated, at that time, the additional work that would be required in the 2019 Rate Case. Thus, DEP's request to recover costs incurred related to the 2019 Rate Case which are above and beyond those provided for in the 2019 First Partial Settlement is approved. Further, the Commission concludes that these additional rate case costs in the amount of $5.384 million as shown on Public Staff Accounting Second Supplemental Exhibit I, Schedule 3-1(t), Line 4, should be amortized over a three-year period.

Regarding rate case expense for this proceeding, the Commission concludes that it is reasonable and appropriate to allow DEP to recover total costs of $6.551 million as shown on Public Staff Accounting Second Supplemental Exhibit I, Schedule 3-1(t), Line 1. Tr. Ex. vol. 24. As previously stated, the issue regarding whether over-amortizations associated with rate case costs approved in Sub 1023 and severance costs approved in the 2019 Rate Case should be used to offset the rate case expense in this proceeding is discussed in other portions of this Order.

The Commission notes that DEP has projected additional rate case expense to be incurred through the date rates will be effective for this proceeding in the amount of $2.526

million as shown on Public Staff Accounting Second Supplemental Exhibit I, Schedule 3-1(t), Line 6, and has requested that the Commission allow DEP to track these costs for possible recovery in a future general rate case proceeding. Tr. Ex. vol. 24. The Commission determines that, in the ordinary course of ratemaking, the rate case expense amount to be recovered from customers should be established in the current general rate case proceeding and not re-evaluated in a future rate case for recovery from customers. Generally, it has been past practice for the Public Staff and the utility to work together to estimate an appropriate amount of rate case expense for approval by the Commission to reflect the activities occurring after the agreed-upon update cutoff date to the conclusion of the hearing or through the preparation of proposed orders. The Commission finds that this practice has been an efficient and reasonable process with respect to determining the appropriate amount of rate case expense to recover from customers. As previously discussed, the Commission's decision in this case to re-evaluate in this proceeding the 2019 Rate Case costs to be recovered in rates is an exception to the Commission's historic practice due to the unusual circumstances occurring during the 2019 Rate Case. Therefore, the Commission denies DEP's request to track and seek future recovery of rate case costs for the present proceeding above the amounts approved herein.

Concerning DEP's adjustment to include the unamortized portion of rate case expense in rate base, the Commission gives significant weight to the Public Staff's testimony stating that the amortization of rate case expense should reflect a normalization of the costs associated with the filing of a rate case, based on an average of the number of years between rate case filings. The Commission notes that the 2019 First Partial Settlement expressly provided that the unamortized balance of rate case expense would not be included in rate base. The Commission concludes that DEP's request to include the unamortized balance of rate case expense in rate base is denied.

Regarding the amortization period over which the current rate case expense of $6.551 million, as netted against a portion of the over-amortization of rate case expenses approved in Sub 1023, should be recovered, the Commission determines that the amortization period over which the rate case expense should be recovered is three years, as this aligns with the MYRP timeframe. Accordingly, the Commission finds and concludes that the three-year amortization period is just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 61

Over-Amortizations

The evidence supporting this finding of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts, Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Summary of Evidence

In its Application, DEP requested permission to apply expiring over-amortizations as an offset to the deferral balances of costs that DEP believed were similar in nature, but which may not yet have been approved by the Commission. The requested offsets include: (1) the

coal combustion residuals (CCR) asset retirement obligation; (2) rate case expenses; (3) application of the over-amortization of severance costs to rate case expenses; (4) application of the over-amortization of early retired coal plants to the Asheville early retired coal plant; (5) application of the over-amortization of Hurricane Matthew to the Winter Storm Izzy proposed deferral; and (6) regulatory fees. Tr. Ex. vol. 7.

DEP Direct Testimony

In direct testimony, DEP witness Jiggetts supported adjustment NC5010, which removes from Test Period costs the amortization of various regulatory assets or liabilities that have been approved by the Commission in previous general rate case proceedings. Tr. vol. 13, 194. Witness Jiggetts testified that the amortization period for the items removed will expire before proposed new rates are effective, and thus should not be included in Test Period expenses on which new rates are based. *Id.* Witness Jiggetts explained that over-amortizations of the regulatory assets and liabilities have been applied to like kind expense recovery in this case. *Id.* Witness Jiggetts testified that DEP intends to apply the over-amortization of the early retired plant regulatory assets against the Asheville Coal plant regulatory asset allowed in the 2019 Rate Case, as an example, and she also testified that over-amortization associated with rate case costs as approved in Docket Nos. E-2, Subs 1023 and 1142 and severance costs approved in the 2019 Rate Case were used to offset the amount requested for recovery in this case. *Id.*

The Public Staff Testimony

Public Staff witnesses Zhang and Boswell recommended that the Commission remove DEP's proposed over-amortization offsets and return the expiring amortizations to customers as single rider over a period of one year with interest. Tr. vol. 19, 73. Witnesses Zhang and Boswell stated that, due to the complexities involved with the associated adjustments, the Public Staff will work with DEP to verify appropriate accounting for the removal of the regulatory assets from the calculation of rate base and propose their inclusion in a rider in their supplemental filing. *Id.* Witnesses Zhang and Boswell explained that currently, regulatory assets are handled on a case-by-case basis, with the recovery period determined by the Commission based on the specifics of the item to be recovered. *Id.* They testified that by offsetting the expiring amortizations against continuing amortizations, DEP is overriding the Commission's approved terms for recovery of the individual regulatory assets. Thus, witnesses Zhang and Boswell testified that the Public Staff recommends returning the over-amortizations to ratepayers through a one-year rider with interest to allow for the refund to customers while maintaining the terms of the Commission's previous approvals of the remaining regulatory assets. *Id.*

DEP Rebuttal Testimony

In rebuttal, DEP witness Jiggetts described each of the expired amortizations that DEP is proposing to offset against like costs: (1) coal ash;[21] (2) rate case costs;

[21] The over-amortization of coal ash costs is separately addressed earlier in this Order.

(3) severance; (4) early retirement of coal plants; (5) Hurricane Matthew; and (6) regulatory fees. Tr. vol. 23, 101-04. Witness Jiggetts explained how DEP's proposed treatment of the expiring amortizations is consistent with the Commission's 2018 Order in the 2017 Rate Case. *Id.* at 100-01; Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-2, Sub 1142 (February 23, 2018) at 224. She stated that in that order the Commission previously addressed continuing amortizations of expired regulatory assets and liabilities in the context of coal ash costs. Tr. vol 23, 100. She further stated that in that order the Commission concluded:

> With regard to DEP's CCR costs from 2018 forward, DEP witness Bateman testified that DEP is requesting to establish a regulatory asset/liability account and defer to this account the portion in annual rates that is more than DEP's actual costs, or the amount in annual rates that is less than DEP's actual costs. In essence, the asset/liability account would be a tool used to true-up the difference in DEP's next general rate case. The Commission agrees with DEP's recommended approach, not only for CCR costs, but also for all cost deferral accounts…. [T]he Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company's next general rate case.

Id. at 100-101.

Witness Jiggetts also disagreed with the Public Staff's assertion that by offsetting the expiring amortizations against continuing amortizations, DEP is overriding the Commission's approved terms for recovery of the individual assets. *Id.* at 100. Witness Jiggetts maintained that DEP has complied with the 2018 DEP Order and has continued the amortization of the expired regulatory assets and liabilities and, in the context of this rate case, is applying those over-amortizations to the deferral balances of costs that are similar in nature, in compliance with the Commission's order. *Id.* at 101.

Witness Jiggetts' also explained the impact upon rates should the Commission adopt DEP's proposed treatment. *Id.* at 104. Witness Jiggetts testified that DEP's approach reduces deferred balances being addressed in the current case, and thereby reduces the base rate revenue requirement, all the while protecting the customers from the rate volatility created by a significant one-year rider. *Id.*

Testimony Presented at the Expert Witness Hearing

At the expert witness hearing, DEP witness Jiggetts answered questions from the Commission regarding the process by which DEP analyzed the rate impact of its proposed treatment of over-amortizations. Tr. vol. 14, 22. Witness Jiggetts walked through DEP's proposal with regard to both coal ash and Winter Storm Izzy. *Id.* at 22-23. Witness Jiggetts explained how applying DEP's proposed treatment to coal ash over-amortizations provides customers a benefit of approximately $3 million. *Id.* at 23. Witness

Jiggetts testified that for - Hurricane Matthew, the over-amortization completely covers what DEP is requesting to defer for Winter Storm Izzy, which means customers would never have to pay for that balance. *Id.* at 23-24.

Discussion and Conclusions

Over-amortization occurs when amortization expense collected in rates (as established in a prior rate case) exceeds the associated regulatory asset or liability. DEP defers such over-amortizations, and the issue in this proceeding is how to utilize such over-amortizations to benefit customers. DEP proposes to apply the over-amortizations to recovery of like kind expenses. The Public Staff proposes to flow the over-amortizations back to customers through a one-year Regulatory Asset/Liability Rider (Rider RAL). The Commission has reviewed the evidence and considered the testimony of the witnesses and determines that, for purposes of this proceeding, it is reasonable and appropriate to offset some, but not all, of DEP's previously approved regulatory assets that have been over-amortized against other regulatory assets.

DEP witness Jiggetts testified that the Commission previously addressed continuing amortizations of expired regulatory assets and liabilities in the context of coal ash costs in the 2018 DEP Order and that DEP's proposal in this proceeding to apply over-amortizations to like kind expenses is consistent with that order. DEP contends that the Commission's conclusion in the 2018 DEP Order that the asset/liability account would be a tool used to account for and subsequently true-up in the next general rate case the difference between the actual amount in annual rates for regulatory assets/liabilities and DEP's actual costs is consistent with its proposal that over-amortizations should be used as a true-up tool with respect to like costs, to be ruled on by the Commission in DEP's next rate case. The Commission disagrees with DEP's interpretation that the 2018 DEP Order approved any sort of offsetting of amortizations between one set of costs that had been approved by the Commission and another set of costs which had not been approved by the Commission for deferral.

The Commission notes that in the 2018 DEP Order cited to by DEP, the Commission allowed DEP to record a specific amount of revenue for its CCR costs as of September 1, 2017, and onward in a deferral account until its next general rate case, with a five-year amortization period. The Commission also stated in the 2018 DEP Order that, if DEP receives revenue for any deferred cost authorized in the 2017 Rate Case proceeding for a longer period of time than the amortization period approved by the Commission for that deferred cost, DEP should continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until DEP's next general rate case. In other words, the Commission directed in its 2018 DEP Order that the asset/liability account utilized for CCR costs be used as a tool to true-up the difference between the portion in annual rates that is more than DEP's actual costs, or the amount in annual rates that is less than DEP's actual costs, in DEP's next general rate case.

The Commission has addressed over-amortizations directly in another docket. In its February 21, 2019 Order Approving Joint Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice, *Application by Carolina Water Service, Inc., of North Carolina for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All of its Service Areas in North Carolina, Except Corolla Light and Monteray Shores Service Area*, No. W-354, Sub 360 (2019 CWSNC Order), the Commission ordered that federal unprotected EDIT funds (a regulatory liability) should be returned to ratepayers through a levelized rider and not be offset through the remaining unamortized portion of a regulatory asset (in this instance, the overcollection in rates of federal income taxes related to the decrease in the federal corporate income tax rate), as the utility suggested. In ordering as such, the Commission explained that:

> [O]ffsetting [a] known and measurable [liability] against either unknown future regulatory assets, or regulatory assets previously approved by the Commission for recovery over a specified period, presents significant intergenerational issues and constitutes inappropriate ratemaking. . . . [T]he amortization period for each regulatory asset is approved by the Commission based upon its determination of what is fair and reasonable for the ratepayers with regard to the costs associated with that specific regulatory asset, or other specific factors taken into consideration by the Commission at the time of that approval. The Commission finds that choosing to simply offset the new . . . liability with the remaining unamortized portion of any regulatory asset would effectively override the Commission's prior decision as to the appropriate amortization period for the regulatory asset, by equalizing the remaining amortization period and the amortization period for the new . . . regulatory liability. And as CWSNC witness DeStefano testified, he is not aware of a situation wherein the Commission has approved such offsetting treatment. . . .
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> [D]eparting from this transparent process in the course of a general rate case simply to offset flowing through the benefit of reductions in an entirely separate category of costs (income taxes) is neither fair nor reasonable. Further, the Commission notes that for customers, a rider will be separately identified on their bills so they can see in dollars and cents the impact of the federal unprotected EDIT flow through. This transparency would not occur with the offsetting proposed by DEP.

2019 CWSNC Order at 55-56. The Commission considered the two costs to be in "entirely separate categor[ies] of costs" such that offsetting one with the other was not justified.

In the proceeding now before us, the Commission examines whether offsetting expiring over-amortizations with new or existing regulatory assets or expenses is justified or in the best interests of ratepayers, when the nature of the two events is similar or the same. The Commission notes that the Public Staff did not present any Commission

precedent, statutory, or rule that over-amortizations must be flowed back to customers via a one-year rider. DEP argues that its proposed approach reduces deferred balances and thereby reduces the base rate revenue requirement which provides a longer-term benefit to customers than the Public Staff's proposed one-year rider. Further, the Commission gives significant weight to the potential implications of the Public Staff's one-year rider proposal upon DEP's credit metrics. As indicated in DEP LFE No. 10, "[g]iven the magnitude of the reduction in cash flow resulting from the Public Staff's proposed $37 million one-year rider, the accelerated flowback puts additional downward pressure upon DEP's already-stressed credit metrics – specifically, the ratio of Funds from Operations (which is essentially a measure of cash flow) to Debt (FFO/Debt). The downward pressure is all the more acute in light of Moody's very recent decision to increase the FFO/Debt downgrade threshold to 21% (up from 20%)."

The Commission finds that DEP's proposal makes intuitive sense in some specific instances because it applies the over-amortization to an actual, Commission-approved cost of the same nature as identified in the course of a general rate case rather than "returning" the over-amortization only to turn around and collect revenue from customers for costs of the same type. However, the Commission determines that similar to the approval of deferral requests, the manner in which to address the true-ups related to over-amortizations in the utility's next general rate case should be determined on a case-by-case basis based on the specific circumstances existing at the time. The Commission finds that, in this specific rate case, DEP's simpler approach to reduce regulatory assets approved by the Commission in this rate case with over-amortizations related to previously Commission-approved regulatory assets is reasonable and appropriate as follows:

a. The over-amortization of rate case expense from Docket No. E-2, Sub 1023 of $1,112,000 should be applied to the balance of rate case expense in the Commission's Order in the 2017 Rate Case $530,000, which will eliminate that balance. The remaining $582,000 of over-amortization should be applied against rate case costs being requested in this proceeding.

b. The over-amortization of early retired plant in the amount of $13.8 million should be applied against the outstanding rate base balance for the Asheville early retired coal plant authorized in the 2019 Rate Case.

c. The over-amortization of Hurricane Matthew costs from the 2017 Rate Case in the amount of $17 million should be treated as follows: First, to recover 2022 incremental Winter Storm Izzy costs of approximately $15 million, and second, the remaining $2 million credit should be refunded to customers through a one-year rider with interest.

Based on the circumstances in this proceeding, the Commission concludes this treatment is reasonable and appropriate because the Commission has carefully reviewed and selected specific "same type" regulatory assets for which the over-amortizations are being applied. The Commission is very clear that same type Commission-approved costs

are being offset by over-amortizations related to same type previously approved regulatory assets. The specific information related to the same type of regulatory assets/liabilities is set forth herein in a manner that is transparent both to the parties and to customers. The Commission concludes that the approved offsetting of over-amortizations reduces deferred balances being addressed in the current case, and thereby reduces the base rate revenue requirement, provides a longer-term impact on rates to customers, protects customers from the rate volatility created by a significant one-year rider, and addresses the potential unfavorable implications of the Public Staff's significant one-year rider proposal upon DEP's credit metrics.

The Commission denies DEP's proposal to apply the over-amortization of severance costs from the 2019 Rate Case in the amount of $907,000 against the rate case costs being requested in this proceeding because these are two entirely separate categories of costs and as such, offsetting one with the other is not justified. The Commission rejects DEP's argument that the offset should be approved because severance costs are labor related, and the rate case costs primarily consist of labor related dollars. The Commission also rejects DEP's proposal that the over-amortization of regulatory fees in the amount of $68,000 should be addressed in a future proceeding but instead finds the over-amortization should be addressed in the present rate case. Thus, the Commission concludes that the over-amortizations related to the regulatory fees, the severance costs, and the remaining $2 million credit from the Hurricane Matthew amortization that DEP proposed to be used to fund the initial balance in the Storm Balancing Account, should be returned to customers through a levelized rider over a one-year period with a return at the weighted average cost of capital.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 62-66

Winter Storm Izzy and Storm Balancing Account

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts and Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Summary of Evidence

DEP Direct Testimony

DEP witness Jiggetts testified as to the incremental O&M costs incurred as a result of Winter Storm Izzy. Tr. vol. 13, 210. She testified that DEP experienced extraordinary storm costs in response to Winter Storm Izzy in January 2022, incurring approximately $23.8 million on a North Carolina retail jurisdictional basis. *Id.* at 211. Witness Jiggetts testified that these amounts are not finalized and that invoices would continue to be received, validated, and paid over the next several months. *Id.* DEP requested to defer the incremental O&M expenses related to Winter Storm Izzy, less approximately $11 million of "normal storm range expense" as that term was defined in the 2017 Rate Case for a total deferral in this proceeding of approximately $12.8 million. *Id.* Witness Jiggetts

testified that, without approval of this deferral request, DEP would face earnings degradation of approximately 35 basis points. *Id.* According to witness Jiggetts, approval of this request would benefit DEP and its customers by helping to ensure investors' confidence in DEP and to assure access to needed capital on reasonable terms and equitable treatment as to deferred costs and revenues. *Id.*

DEP witness Jiggetts also testified as to DEP's request for approval of a new methodology for tracking storm costs incurred. Tr. vol. 13, 212. Witness Jiggetts testified that the regulatory asset approved for Hurricane Matthew storm costs in the 2017 Rate Case was fully amortized as of September 2021, and per the Commission's order in that case, DEP has continued to record the amortization and has a regulatory liability on its books. *Id.* Witness Jiggetts testified that DEP is seeking to use this existing regulatory liability to create a "balancing account" for storm costs going forward, starting with DEP's request to apply the excess amortization from Hurricane Matthew to the deferred costs for Winter Storm Izzy. *Id.* Witness Jiggetts explained that, to this end, Adjustment NC7010 establishes an average amount of incremental storm costs included in customer rates. *Id.* Witness Jiggetts testified that under DEP's proposal, each year, if the incremental storm expenses are over the average amount in rates, the difference would be deferred to the account; if the incremental storm expenses are under the average amount in rates, the difference would be contributed to the account. She testified that if the average amount included in customer rates approximates the average amount of storm expense going forward, the balancing account balance should fluctuate around zero and not require additional funding. *Id.* She further stated that if the account does require additional funding, this could be evaluated in a future rate case or storm securitization proceeding. *Id.* at 212-13. Witness Jiggetts testified that the Storm Balancing Account would allow DEP to recover its actual costs for storm restoration efforts and ensure that DEP does not make or lose money related to its storm restoration efforts. *Id.* at 213.

DEP witness Jiggetts also testified as to how she calculated a storm normal expense amount of $17.8 million based upon a ten-year average of storm costs, after removing costs associated with major storms, to be included in rates consistent with prior Commission orders. Jiggetts Supplemental Ex. 4, Tr. Ex. vol. 14.

The Public Staff Direct Testimony

Public Staff witnesses Zhang and Boswell did not make an adjustment to DEP's storm normalization calculation. Public Staff Accounting Ex. 1, Tr. Ex. vol. 19.

Witnesses Zhang and Boswell disagreed that DEP should be permitted to defer costs associated with Winter Storm Izzy, stating that the Public Staff maintains its position as articulated in its initial comments filed on March 15, 2017, in the 2017 Rate Case and Docket No. E-2, Sub 1131, that it is appropriate and reasonable that DEP only be allowed to defer the difference between its actual incremental O&M expense related to Winter Storm Izzy and a normal amount of $27.4 million on a North Carolina retail jurisdictional basis. Tr. vol. 19, 54. In light of the fact that DEP had, at the time it filed its Application in this proceeding, estimated the costs of Winter Storm Izzy to be approximately $23.8

million on a North Carolina retail jurisdictional basis, the Public Staff stated that the costs associated with this storm would not qualify for a deferral. *Id.* The Public Staff explained that, merely because the storm costs incurred in a given year are greater than $11 million (the normalized level from a prior rate case), it cannot simply be assumed that the larger expense is extraordinary in magnitude and therefore suitable for deferral. *Id.* Witnesses Zhang and Boswell stated that actual storm expenses included in the ten-year average spanned a wide range of annual amounts, from a storm amount as low as $4,901 to as high as $461.974 million, and, as such, at least $27.4 million should be considered an appropriate level of normal storm expense for purposes of consideration of DEP's $23.8 million in deferral costs. *Id.* at 54-55. In the event that the costs associated with Winter Storm Izzy exceed the $27.4 million North Carolina retail amount, the Public Staff suggested that DEP may file for a deferral or securitization, whichever is most beneficial to ratepayers. *Id.*

Additionally, the Public Staff did not agree with DEP's proposal to create a storm balancing account and stated that creating such an account would only serve to transfer all risk from DEP to ratepayers, including placing unaudited costs into a deferral for recovery. *Id.* at 53. The Public Staff stated that DEP already has ample opportunities to recover storm costs, whether that be through storm normalization, securitization, or deferrals, all of which may allow DEP to reasonably and appropriately recover actual audited storm costs. *Id.*

DEP Rebuttal Testimony

DEP witness Jiggetts testified on rebuttal that the Public Staff accurately summarizes DEP's intent in proposing the storm balancing account. Tr. vol. 23, 83. Witness Jiggetts explained that the Commission should implement a mechanism that results in DEP's neither making nor losing money because of storm restoration efforts. *Id.* Witness Jiggetts responded to the Public Staff's assertion that the storm balancing account would transfer risks from the utility to ratepayers and would include unaudited costs for recovery. *Id.* at 83-84. Witness Jiggetts testified that the base level of storm expense that must be exceeded before DEP can request deferral, as established in the 2017 Rate Case, has in practice been inequitable to DEP as the base level of storm expense is greater than the amount of storm normal expense included in base rates, which results in that difference being borne by shareholders. *Id.* at 84. Witness Jiggetts explained that when DEP's linemen repair and replace damaged lines and equipment after a storm event, the outcome is the restoration of utility service for DEP's customers. *Id.* Witness Jiggetts stated that it is DEP's position that these storm restoration expenses are a cost of service of the regulated utility that are reasonably and prudently incurred and should be recovered from customers. *Id.*

Witness Jiggetts also responded to the Public Staff's second assertion and explained that the deferral of the amounts to the balancing account does not preclude those amounts from being subject to audit or review by the Public Staff or the Commission. *Id.* at 86. Witness Jiggetts testified that deferrals, by their nature, are unaudited amounts when initially recorded, but that when the amounts in the balancing account are put forth for recovery or

return to customers in a future case or securitization, the activity and related balance will be subject to audit for reasonableness and prudency. *Id.*

In her third and final supplemental testimony, witness Jiggetts updated the storm normalization calculation to $22.2 million. Jiggetts Supplemental Ex. 4, Tr. Ex. vol. 14. In its exhibits to settlement testimony, the Public Staff similarly utilized $22.2 million for DEP's storm normalization calculation. Public Staff Accounting Ex. 1, Tr. Ex. vol. 19.

The Public Staff Supplemental and Settlement Testimony

In its supplemental and settlement testimony, the Public Staff testified that, based upon the updated numbers provided in witness Jiggetts' supplemental filings with regard to the costs of Winter Storm Izzy and other 2022 storms, it recommends that the costs incurred for Winter Storm Izzy be recovered through securitization. Tr. vol. 19, 91.

Testimony Presented at the Expert Witness Hearing

At the expert witness hearing, DEP witness Jiggetts explained the methodology for the calculation of storm normalization of $22.2 million in this case and testified that the Public Staff agreed with her storm normalization calculation. Tr. vol. 14, 29-30; 57-58.

Public Staff witnesses Zhang and Boswell explained at the expert witness hearing that, while the costs contained in DEP's initial filing did not rise to the level of warranting deferral, DEP's inclusion in a supplemental filing of costs associated with Hurricane Ian – when viewed together with Winter Storm Izzy costs – met the threshold warranting deferral or securitization of the costs. Tr. vol. 19, 150-51.

At the expert witness hearing, DEP witness Jiggetts described the mechanics of DEP's proposal for a storm balancing account and how it is accomplished using a visual aid. DEP Redirect Jiggetts Direct and Settlement Ex. 2, Tr. Ex. vol. 14. Witness Jiggetts explained how the exhibit shows that in Year 1 DEP experienced $25.65 million in storm restoration costs (apart from major storms where costs would ordinarily be deferred or securitized). Subtracting that amount from "storm normal" ($22.2 million) leaves an under-recovery of $3.45 million, which is deferred to the Storm Balancing Account, meaning that at its inception in this example, the account is a Regulatory Asset. In Year 2, however, DEP experiences only $10.15 million in storm restoration costs. After accounting for the existing balance in the account ($3.45 million) and Year 2's "storm normal" (again, $22.2 million), the balance in the account has now shifted to a Regulatory Liability of $8.6 million – that is, over the two year period in the example, DEP collected "storm normal" costs in rates amounting to $44.4 million, and experienced restoration costs associated with "normal" storms of $35.8 million, leaving a balance in the account of $8.6 million in favor of customers.

Witness Jiggetts clarified that the initial building block for the storm balancing account is the calculation of the storm normal expense, which is the amount already in rates. Tr. vol. 14, 27-31. Witness Jiggetts testified that, as originally approved by the

Commission in DEP's 2012 Rate Case, Docket No. E-2, Sub 1023, "storm normal" embeds average storm restoration costs in rates over a 10-year period, after excluding costs which would ordinarily be deferred or securitized. She explained that deferral or securitization applies to major storms, so the "storm normal" calculation is designed to have a baseline level of storm restoration cost in rates derived from a 10-year average. *Id.* at 28-30. In this case, the "storm normal" cost to be embedded in rates is $22.2 million, a figure with which the Public Staff agrees. *Id.* at 30.

Witness Jiggetts testified that, as proposed, the account would have a regulatory liability of approximately $2 million (in favor of customers), which would extinguish costs associated with Winter Storm Izzy but also lower returns, since the funds would be in rate base. Tr. vol. 14, 62-63. Witness Jiggetts stated that this regulatory liability position would continue until the next general rate case and, even though the balance in the account would change from year to year based upon storm costs actually experienced from a rates charged to customer perspective that the initial $2.27 million credit, would stay reflected in rates until DEP returns for a rate case proceeding. *Id.* at 63.

Discussion and Conclusions

As noted above, the Commission has approved DEP's calculation in this proceeding for the storm normalization expense to be included in rates.

The Commission stated in its Order in the 2017 Rate Case that both DEP and the Public Staff cite in support of their positions in this case with regard to the issues concerning the recovery of storm costs:

> The Commission's precedents do not require that ratepayers bear the entire cost of repairing the damage to a utility's system resulting from a major storm. Instead, deferrals of storm costs are limited to those costs that are beyond the normal range of fluctuation of storm costs from year (in this case, costs in excess of $27.4 million). In recent general rate cases, the Commission has also included in the utility's rates a storm cost allowance based on the average amount the company has incurred over a period of years (the storm cost allowance approved in Sub 1023 was $12.7 million per year). Costs may exceed an average, or normal, amount used to set rates in a general rate case; however, as long as those excess costs are within a normal range of variation, they should be presumed to be recovered through the utility's rates in effect at that time (given the fact that many expenses fluctuate from year to year).

Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, *Application by Duke Energy Progress, LLC, For Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1142, at 127 (Feb. 23, 2018) (2017 Rate Case Order).

Based upon DEP's spending of $87.126 million on a North Carolina retail jurisdictional basis in 2022 on annual storm costs, which is above the annual threshold of $27.4 million on a North Carolina retail jurisdictional basis in annual storm costs that the Public Staff agreed is proper for seeking deferral or securitization, the Commission is satisfied that DEP has met the threshold warranting a deferral or securitization for Winter Storm Izzy and Hurricane Ian. As discussed herein, the Commission concludes that DEP should be allowed to recover the 2022 incremental Winter Storm Izzy costs of approximately $15 million, which amount was agreed to by the Public Staff, by applying a portion of the over-amortization of Hurricane Matthew costs in the amount of $17 million from the 2017 Rate Case. As stated elsewhere in this Order, the remaining amount of over-amortization of Hurricane Matthew costs, approximately $2.0 million, should be returned to customers through a levelized rider over a period of one year.

With regard to the proposed storm balancing account, the Commission described the position taken by DEP in the 2017 Rate Case proceeding (that all costs in excess of a normalized annual amount should be considered extraordinary and recovered on a deferred basis) as potentially "set[ting] a dangerous precedent for other categories of costs in the future." 2017 Rate Case Order at 130. More specifically, the Commission stated explicitly that:

> Under this approach, the Company would be assured of recovery of all its storm costs on almost a "true-up" basis, either through the presumed annual allowance in rates or through deferral and amortization. In effect, DEP's proposal would amount to a "tracker" system for storm cost recovery, similar to the riders established by the General Assembly in G.S. 62-133.2, 62-133.8 and 62-133.9 for fuel, REPS, and DSM/EE cost recovery. If DEP is allowed to implement such a system for recovery of its storm costs, other utilities may well seek to adopt a similar approach for any of various other expense items. In light of this concern, and the attendant shifting of more risk to customers, the Commission has generally been reluctant to approve cost tracker systems, except when they are required by statute.

Id.

In this case, and at this time, the Commission is unpersuaded by DEP's contentions that there is any reason to begin allowing, in essence, a true-up of storm costs where such recovery is not explicitly statutorily permitted. Further, the Commission continues to have concerns that DEP's proposed approach might set precedent for other categories of costs in the future. The Commission notes that any storm costs not eligible for securitization or deferral are presumed to be covered by DEP's authorized base rates. For these reasons, the Commission declines to approve a storm balancing account, at this time, as requested by DEP.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 67-69

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Abernathy, Jiggetts, Harris, Quick, Bateman and Stillman, Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

IIJA/IRA

By Application and through the direct testimony of witness Abernathy, DEP requests to defer the estimated tax benefits, net of costs, associated with the IRA and IIJA. Tr. vol. 23, 151, 154.

With respect to the IRA, DEP witness Panizza discussed the two solar MYRP projects and six battery energy storage MYRP projects that are eligible for either Investment Tax Credits (ITC) or Production Tax Credits (PTC) made available under the IRA. Tr. vol. 16, 140-44. Witness Abernathy explained how DEP estimated the IRA benefits based on the best information available and that DEP's intention is for customers to receive the full benefit (net of costs) of the tax credits. Tr. vol. 23, 151. Witness Abernathy also testified that "the Company agrees [with the Public Staff] that a deferral of IIJA impacts is appropriate and supports the recommendation for the Commission to approve an accounting order to defer any incremental revenue requirement impacts, including benefits and costs related to IIJA, to be addressed in a future rate case." Tr. vol. 23, 154.

Public Staff accounting panel witnesses Boswell and Zhang, as well as Public Staff witness Thomas, testified in support of the requested deferral treatment of the IRA impacts. Tr. vol. 19, 77, 178-80, 195. Public Staff witness Nader provided similar testimony, recommending that the Commission treat the impacts associated with the IIJA consistent with those related to the IRA. Tr. vol. 21, 114.

Based on foregoing, the Commission concludes that DEP's request for an accounting order authorizing deferral of all IRA and IIJA related impacts, net of costs, as well as any difference between realized and estimated impacts included in DEP's filing is reasonable and should be approved.

Customer Assistance Program, Payment Navigator Program, and the Tariffed On-Bill Program

In her direct testimony, DEP witness Jiggetts explained that DEP has proposed several new programs in this case to benefit customers, including the CAP, Tariffed On-Bill program, and the Payment Navigator program (Customer Programs) and that DEP would incur certain implementation and administration costs that were not included in the test period, and which are not known and measurable at this point. She stated that should the Commission approve the Customer Programs, DEP requests permission to establish a regulatory asset and defer to the account the incremental implementation and

administrative O&M costs related to the programs for future recovery in rates. Witness Jiggetts also testified that DEP is proposing PIMs as part of its PBR application and that DEP requests to defer to this regulatory asset the implementation costs for the PIMs, including, without limitation, certain costs relating to marketing, administration, and the PIMs dashboard. Tr. vol. 13, 209.

DEP witnesses Bateman and Stillman testified that the PIMs dashboard had a capital cost estimate of $540,000, with estimated annual O&M costs of approximately $100,000, with DEP proposing to allocate 43.23% of these costs to DEP's North Carolina retail customers. Tr. vol. 14, 112.

Public Staff witnesses Zhang and Boswell testified that the proposed deferral of the costs associated with the implementation of the proposed Customer Programs and PIMs fails to meet either prong of the Commission's two-prong test for deferrals, and therefore DEP's request should be denied. Tr. vol. 19, 75-76. They further testified that because PIMS are designed to protect ratepayers and are required for approval of an MYRP, PIMs are part of DEP's normal course of business and should also be denied on that basis. *Id.* at 75-76.

In her rebuttal testimony, witness Jiggetts responded to the Public Staff's recommendation to deny DEP's request on the basis of the deferral test. Tr. vol. 23, 105. Witness Jiggetts testified that DEP's request is being included as a part of its general rate case proceeding and is not an "out of period" cost subject to the Commission's two-prong deferral test. Witness Jiggetts explained that even though the costs of implementing these programs are known and measurable, DEP did not adjust operating expenses in this case to include these incremental costs which are not captured in the historic test period. *Id.* at 106. Witness Jiggetts clarified that while PIMs will become a part of DEP's normal course of business as a result of the MYRP, the costs of that new normal course of business have not been included in operating expenses for recovery from customers. *Id.* Thus, witness Jiggetts explained that creation of a regulatory asset for deferral of the costs would allow DEP to postpone recovery of these costs until the Customer Programs are implemented and benefitting customers. *Id.*

At the expert witness hearing, responses to the Public Staff discovery requests were entered into the record in which DEP indicated that many of the costs associated with implementation of the PIMs were minimal. Public Staff Cross Examination Bateman Stillman Direct and Settlement Ex. 1, Tr. Ex. vol. 16.

The Commission has historically treated deferral accounting as a tool to be allowed only as an exception to the general rule, and its use has been allowed sparingly. Deferred accounting treatment is generally authorized by the Commission only in those instances where there was a clear and convincing showing that the costs in question were of an unusual or extraordinary nature and that, absent deferral, the costs would have a material impact on the company's financial condition. Requests for the use of deferral accounting have been historically considered by the Commission on a case-by-case basis and such decisions are based on the specific circumstances of the request.

The Commission considers program proposals such as the Customer Programs, to be a normal part of DEP's operations to provide benefits to customers with respect to billing and payment options and other customer service offerings pertaining to the provision of electric utility service. With respect to PIMs, the Commission acknowledges that this is the first time the Commission is considering PIMs in a general rate case proceeding; however, PIMs are now statutorily part of the normal course of business when a utility elects in its discretion to pursue an MYRP. Accordingly, DEP's request to defer these costs is denied. To the extent that there are ongoing O&M expenses associated with implementation of the PIMs and customer programs, DEP may seek cost recovery of actual expenses incurred during a future test period in its next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 70

Interconnection CIAC Regulatory Liability Recommendation

The evidence supporting this finding of fact is contained in DEP's verified Application and Form E-1; the Revenue Requirement Stipulation; the testimony and exhibits of DEP witness Speros and Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

Public Staff witness Metz explained that in relation to interconnection agreements (IAs), Contributions in Aid of Construction (CIAC) are funds provided to DEP by third party utility customers to pay for capital projects (usually new construction) typically requested by the third party. Tr. vol. 16, 452. Witness Metz testified that during his review of IAs between third party qualifying facilities (QFs) and DEP, he discovered that DEP had historically recorded QF developer CIAC payments as revenue rather than an offset to rate base. *Id.* Witness Metz stated that a QF developer is responsible for the cost of the network upgrades required for interconnection and that the costs are not socialized to all ratepayers unless otherwise permitted by law to ensure that the ratepayers are held harmless. *Id.* He explained that DEP performs a study to determine what network upgrades are necessary for the safe and reliable interconnection of the developer's project. DEP then charges the third-party developer for the construction costs of the identified network upgrades. *Id.* Witness Metz testified that ratepayers should be held harmless if the network upgrades are paid for in whole by the developer, plus any additional true up costs, once the project is online. *Id.* Witness Metz stated that the Public Staff attempted to determine the magnitude and resulting rate impact of this issue; however, more time was needed to audit, validate, and review this issue given the complexity. *Id.*

Witness Metz testified that DEP self-identified errors related to recording CIAC interconnection activity during a 2019 audit but deemed it as not material. *Id.* at 452-53. The audit findings stated that DEP's practice of recording CIAC from developers to the income statement as Other Revenue while charging costs incurred to complete construction to CWIP balance sheet accounts is incorrect. *Id.* at 453. To correct this issue, the audit findings instructed that the CIAC should be recorded to CWIP. *Id.* Witness Metz stated that DEP reviewed this topic again during a 2022 follow-up audit and that the audit

findings recognized that DEP's process improvements have strengthened tracking of the interconnection financial activity. *Id.* However, the audit findings determined that a comprehensive process documentation needs to be established to define roles and responsibilities and to ensure sustainability of the financial processes. *Id.* A deadline of June 2023 was established for DEP to prepare this documentation. *Id.*

Public Staff witnesses Zhang and Boswell testified that DEP booked these CIAC payments inconsistently, leaving the Public Staff unable to determine whether ratepayers were held harmless regarding the costs associated with these interconnections. Tr. vol. 19, 39. Witnesses Zhang and Boswell further testified that DEP changed its booking procedures for the fees received for interconnections at the beginning of 2022. *Id.* The Public Staff witnesses asserted that they were unable to determine the magnitude of the error, whether ratepayers have been harmed, and if so by how much or whether DEP's new procedures will alleviate the issues. Tr. vol. 16, 453; Tr. vol. 19, 39. Therefore, the Public Staff recommended that the Commission order DEP to produce all entries related to the IAs for all plant, depreciation, and collections so the Public Staff can determine whether ratepayers have been held harmless. *Id.* Additionally, the Public Staff recommended that a regulatory liability be established to record any instances in which DEP incorrectly recovered costs associated with IAs from ratepayers, to be flowed back to ratepayers with interest at DEP's weighted average cost of capital in the next DEP general rate case. *Id.* at 39-40. Witnesses Zhang and Boswell testified that since DEP had full control over its accounting systems and should have booked the amounts correctly, any items found to have been booked that should have been recovered from ratepayers should not be credited to the regulatory liability. *Id.* at 40. Witnesses Zhang and Boswell recommended that the Commission order DEP to review its CIAC policy and report the results of that review in the next general rate case. *Id.*

DEP witness Speros took exception to the Public Staff's recommendations and argued that the establishment of a regulatory liability has not been justified in this case. Tr. vol. 13, 60. Witness Speros explained that DEP has taken a number of steps to ensure CIAC associated with IAs is appropriately recorded on DEP's books. *Id.* He stated that this process begins with DEP's monthly reconciliation of associated liability accounts. *Id.* For Transmission projects, a monthly journal entry is made to credit capital projects for customer deposits based upon the cost incurred. *Id.* For distribution projects, quarterly journal entries are made to credit the capital projects for customers based upon costs incurred. *Id.* Witness Speros stated that DEP's project controls organization and finance organizations then work together to ensure that the current list of IA projects is appropriately analyzed so that proper journal entries are made, whether a debit or credit to the construction project. *Id.* Moreover, witness Speros explained that DEP continually works to improve its accounting processes, including the process for recording CIAC associated with IAs. *Id.* at 61. He commented that since 2019, DEP has taken steps to improve the processes in place for recording CIAC associated with IAs and made recent modification in 2022. *Id.* Witness Speros also explained that DEP has not been able to identify any interconnection costs associated with CIAC that ratepayers should not have been charged in DEP's last general rate case. Tr. vol. 13, 62.

Witness Speros also testified that the Public Staff's broad-based recommendation to order DEP to produce all entries related to IAs for all plant, depreciation, and collections is unnecessary to demonstrate that DEP's procedures are working properly. *Id.* at 61. In the alternative, DEP offered to work with the Public Staff in a collaborative fashion to facilitate their review and help identify information that would best provide a reasonable and efficient evaluation. *Id.* at 61-62. DEP also did not oppose in principle reporting to the Commission on its CIAC policy in the next general rate case. *Id.* at 63.

No other intervenors raised an issue regarding DEP's accounting for CIAC associated with IAs.

The initial Revenue Requirement Stipulation identifies as unresolved the issue of whether it is necessary for DEP to establish a regulatory liability to address CIAC for IAs as recommended by the Public Staff. As discussed below, the Commission concludes that the evidence in this case does not support the establishment of a regulatory liability to address CIAC collected by DEP from interconnection customers.

Fundamental to the establishment of a regulatory liability for CIAC related to IAs is a showing that the establishment of a regulatory liability is justified. In this case, the Public Staff offered very little in the way of justification to support the establishment of a regulatory liability. The Public Staff testified that it had found inconsistencies in the financial accounting of the CIAC related to IAs and that it was unable to determine whether ratepayers are being held harmless. Witness Metz acknowledged that the Public Staff needed more time to audit, validate, and review this issue given its complexity. Beyond these statements, the Public Staff witnesses were not in a position to demonstrate to the Commission the magnitude and rate impact on customers of this issue such that the establishment of a regulatory liability would be justified. Instead, the Public Staff requested that the Commission require DEP to produce all entries related to IAs for all plant, depreciation, and collections to allow the Public Staff to continue its audit of this issue beyond the conclusion of the present rate case proceeding.

The explanations provided by DEP witness Speros in his rebuttal testimony are informative as to the steps that DEP has taken to record CIAC for IAs in a manner that does not harm customers. As witness Speros explained, DEP has worked to improve its CIAC accounting procedures since 2019, with additional improvements made as recently as 2022. Further, as a result of the follow-up audit in 2022, a June 2023 deadline was established for DEP to document processes and define roles and responsibilities related to the financial accounting of CIAC related to IAs. The Commission determines that the requirement for DEP to construct this documentation should facilitate sustainability of DEP's improved financial processes. DEP should provide the Public Staff a copy of its documented processes related to this issue once the documentation is completed.

The Commission concludes that the Public Staff's proposal to establish a regulatory liability is not warranted at this time, given the uncertainty regarding the magnitude of the issue. In so concluding, the Commission gives weight to the testimony of witness Speros that

DEP has been unable to identify any interconnection cost associated with CIAC that ratepayers should not have been charged in DEP's last general rate case.

Based upon all of the evidence presented, the Commission concludes that the establishment of a regulatory liability is not justified by the record in this proceeding. DEP shall continue its work with the Public Staff regarding the documentation of its processes related to the recording of CIAC and shall report on the CIAC issue in its next general rate case application as required by the Revenue Requirement Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 71

Quality of Service

The evidence supporting this finding of fact is set forth in the testimony of DEP witnesses Guyton, Maley, and Quick and Public Staff witness T. Williamson.

DEP witnesses Guyton and Maley testified to the performance of the DEP transmission and distribution systems during the base period. Witness Maley testified that DEP's transmission system is reliable and well-maintained, and that DEP is seeking to continue transmission investments to facilitate the conversion of the transmission system to meet future demands. Witness Maley further indicated that DEP utilizes the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) metrics to measure outage durations and that these metrics over the base period showed a downward trend in outages (and therefore an upward trend in reliability). Witness Maley indicated that the transmission system also utilizes an Outages per Hundred Miles per Year – Sustained Automatic (OHMY-SA) metric which has further demonstrated the reliability of the DEP transmission system. Tr. vol. 10, 176-77. Witness Guyton testified that DEP's operational investments since its last rate case have allowed it to meet its operational performance and customer satisfaction goals and that it is providing safe and reliable service. *Id.* at 48. Witness Guyton also cited DEP's SAIDI and SAIFI scores as indicative of increasing system reliability in the form of reduced customer outages. He attributed this improvement in outage experience to ongoing grid improvements such as Self-Optimizing Grid improvements as well as ongoing vegetation management activities. *Id.* at 50.

In his direct testimony, Public Staff witness T. Williamson largely concurred with DEP's conclusions about improving service quality and attributed the stable to improving system performance to DEP's Grid Improvement Plan and vegetation management activities. Tr. vol. 21, 222. Witness T. Williamson also engaged in an in-depth analysis of DEP's service quality in which he examined various aspects of DEP's performance in initiating new service, providing normal day-to-day service, and restoration of service after outage events. *Id.* at 218-33. Witness T. Williamson also summarized various consumer statements of position filed with the Commission relative to this rate case. *Id.* at 233-35.

Regarding the initiation of new service, witness T. Williamson indicated that new service installations had almost doubled from 2015 through 2022 but that DEP's average

percentage of installations completed within 20 days had improved in recent years from historic averages and was in the low to mid 90s from 2020 forward. Witness T. Williamson also noted that the sheer number of new connections experienced by DEP in 2022 was having an impact on the ability to complete new installations quickly but that DEP still averaged to meet the 20-day goal 92.6% of the time in 2022. Witness T. Williamson also noted that "[t]he average business days to construct [new connections] has been consistently around the 10-day range and the average percent within 20 days has been consistently around the 95% range since 2019." *Id.* at 219-20. Regarding day-to-day service, witness T. Williamson reiterated that SAIDI and SAIFI scores have been trending downward since 2017 in part because of GIP program implementation which "provides a level of predictability concerning future service levels, to the benefit of customers. *Id.* at 222. Witness T. Williamson further testified that service reliability as measured by ASAI[22] has consistently measured more than 99.97% since 2013. *Id.* at 226. With respect to restoration of service after an outage, witness T. Williamson testified that DEP's Estimated Time to Restoration for service outages was met in 92% of Major Event Day outages. *Id.* at 232.

In her direct testimony, DEP witness Quick testified that in addition to DEP's primary responsibility of providing safe and reliable service, DEP understands that its customer base has diverse service needs and strives to recognize and accommodate them where possible. Tr. vol. 7, 67-68. She outlined the steps that DEP is taking to continue to improve customers' experiences and satisfaction. Tr. vol. 7, 65. With respect to DEP's customer care operations, witness Quick explained that they designed and continuously enhanced to ensure that customer inquiries are answered promptly and accurately. Customer calls are either processed in the Interactive Voice Response (IVR), allowing customers to self-serve, or by a call center specialist. Tr. vol. 7, 67. She also described how DEP uses social media channels to inform customers about reliability updates in their area and changes that could impact their bills. Additionally, in an emergency or major storm, DEP uses social media to communicate essential information to customers, making proactive posts to quickly warn as many customers as possible and engage with customers who have storm- or outage-related questions. Tr. vol. 7, 69-70.

Witness Quick also testified about the programs that DEP supports to help customers with the affordability of electric utility service. She noted the energy efficiency programs that help reduce energy usage and provide weatherization assistance. Tr. vol. 7, 71-73. She also detailed DEP's numerous efforts to support customers during the unprecedented COVID-19 pandemic. One example she gave was DEP's expansion and extension of the Winter Moratorium, a period from November until March every year where qualified customers are protected from disconnection for non-payment. DEP ensured the Winter Moratorium remained in place from November 2020 until March 2022, protecting approximately 48,000 eligible customers from disconnection during the initial and subsequent COVID-19 pandemic waves. Another example was the outreach campaigns to municipal leadership, community stakeholders, Chambers of Commerce, state agencies, food banks, and churches where

[22] ASAI is the ratio of the total number of customer hours that service was available during a given time period to the total number of customer hours demanded. Algebraically, this ratio is represented as follows: ASAI = 1 – (SAIDI/8760).

DEP communicated with customers to promote options for assistance and contacting DEP. Tr. vol. 7, 81-88.

Witness Quick further testified about recent digital enhancements to improve service to customers. She relayed that after receiving customer feedback, DEP improved its website by making interaction operations easier to locate in January 2022. Additionally, she described an interactive Transmission Map that details transmission projects planned across North Carolina, a planned vegetation management map, a feature alerting customers to estimated call wait times, the ability for customers to start and stop service online, and a digital, and a self-service enrollment option for payment arrangements. Moreover, witness Quick highlighted that DEP's digital enhancements made it easier for customers to report service interruptions. She also testified that DEP offers a fee mobile app that allows residential and small business customers to easily manage their account from anywhere in the United States. Witness Quick stated that since making these changes, customers are reporting higher satisfaction with their web experiences. Tr. vol. 7, 96-105.

In recognition of the policy of the State of North Carolina "to promote adequate, reliable and economical utility service" codified at N.C. Gen. Stat. § 62-2(2) and in accordance with the Commission's general supervisory authority established in N.C. Gen. Stat. § 62-32, and recognizing that the Commission found DEP's service quality to be "good" in the 2019 Rate Case and that the performance metrics for service rendered have not declined and, in some cases, have improved since that rate case, as is reflected in witness Williamson's testimony, the Commission concludes, based on the record in this proceeding, that the quality of service provided by DEP's is good. No other party presented evidence on DEP's service quality.

Additionally, no other party presented evidence critical of DEP's quality of service. Based on the foregoing, the Commission concludes that DEP provides adequate service to customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 72-73

Tax-Related Items

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witness Jiggetts, Public Staff witnesses Zhang and Boswell; and the entire record in this proceeding.

In its Application, DEP proposes to revise the EDIT-4 rider to return an additional $16.2 million for unprotected federal EDIT and $4.5 million for deferred revenues to customers over the remaining 2.7 years of the total five years to return the unprotected federal EDIT approved in the prior rate case. The two-year period for Deferred Revenues under EDIT-3 will expire in June of 2023; therefore, DEP is proposing to flow the additional amounts back to customers over the remaining life of the EDIT-4 rider in lieu of creating a new decrement rider. *Id.*

DEP witness Jiggetts supports this revision to the EDIT-4 Rider in her direct testimony and in Jiggetts Exhibit 3. Tr. vol. 13, 164. The Public Staff agrees with DEP's proposal to flow back the incremental amount to customers on a levelized basis over the remaining EDIT rider term; however, the levelized return rate used by the Public Staff reflects DEP's 3.88% cost of debt rate and a return on equity of 9.25% from December 31, 2022. Tr. vol. 23, 107.

In her third supplemental testimony, witness Jiggetts updated DEP's cost of debt to 4.03% as of March 31, 2023, and recalculated the proposed changes to the EDIT-4 Rider accordingly. Tr. vol. 13, 240, 242. In the initial Revenue Requirement Stipulation, the stipulating parties agree to an embedded cost of debt of 4.03%. Revenue Requirement Stipulation § III.1, Tr. Ex. vol. 7.

Based on the foregoing, the Commission concludes that DEP's proposal to revise the EDIT-4 Rider to return additional unprotected federal EDIT to customers over the remaining life of the EDIT-4 Rider, as supported by the Public Staff, is just and reasonable and should be approved. Further, the Commission finds and concludes that the levelized return rate should be based on the 4.03% embedded cost of debt agreed to by the stipulating parties in the initial Revenue Requirement Stipulation and the capital structure and rate of return on equity approved by the Commission in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 74-75

Equal Percentage Allocation, Base Fuel and Fuel-Related Factors and Fuel Cost Allocation

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Hager, and Jiggetts, the testimony of Public Staff witnesses Lucas, and McLawhorn, and Zhang and Boswell, and the testimony of CIGFUR witness Phillips, and the entire record in this proceeding.

In its Application and Form E-1, the fuel rates presented by DEP were allocated to customer classes utilizing the equal percentage fuel adjustment.

Public Staff witness Lucas testified that DEP currently allocates fuel cost adjustments to customer classes based on an equal percentage change, meaning that fuel and fuel-related costs are recovered using a uniform percent increase or decrease per rate class such that each rate class will, on average, experience the same average monthly percent increase or decrease as the overall fuel and fuel-related cost change. Tr. vol. 20, 28. Public Staff witness Lucas testified that since 2008, DEP has allocated fuel cost increases on an equal percentage basis to each of its five customer classes as allowed by Session Law 2007-397. Tr. vol. 20, 28. He testified that the Public Staff first supported the use of equal percentage allocation in DEP's 2008 fuel adjustment proceeding, Docket No. E-2, Sub 929. He cited several reasons for the Public Staff's agreement to the equal percentage allocation, such as the uncertain economic times and

the large increase in fuel costs. *Id.* at 29-30. He noted that the equal percentage method of adjusting rates assisted industrial customers financially during the Great Recession and during a period of unprecedented increases in coal prices at the expense of other customers. Id. at 28-31. He testified that the distortion that can be created by equal percentage fuel adjustments is found in DEP's most recent 2022 fuel rider proceeding, in which fuel costs increased for all customer classes except LGS, which received a fuel rate decrease. Id. at 30-35. He explained that, for this reason, it is the Public Staff's recommendation that the Commission does not allow DEP to make equal percentage fuel adjustments but allow DEP to continue to offer voltage differentiated rates. *Id.*

Witness Lucas stated that N.C.G.S. § 62-133.16(b) requires the Commission to allocate the utility's total revenue requirement among customer classes based on the cost causation principle and minimize cross subsidies "to the greatest extent practicable." *Id.* at 33-35, 53, 103. Witness Lucas noted that the statute defines the cost causation principle to mean "establishment of a causal link between a specific customer class, how that class uses the electric system, and costs incurred by the electric public utility for the provision of electric service." *Id.* at 33.

Witness Lucas presented the current fuel rates adjusted to remove the equal percentage allocation method. *Id*. at 36. As set forth in his Table 4, the rates in cents per kWh, excluding the regulatory fee, are 2.647 for residential customers, 2.654, for SGS customers, 2.609 for MGS customers, 2.516 for LGS customers, and 2.511 for Lighting customers. *Id.* at 36.

In his direct testimony, CIGFUR witness Phillips provided support for the equal percentage methodology. Tr. vol. 21, 487-88. He testified that the methodology has been approved without objection by any party in every annual fuel charge adjustment proceeding since 2008 and that the method has served ratepayers well and should be continued to be utilized. *Id.* He further stated that the methodology levelizes over time any harsh impacts and results in equal percentage increases or decreases to all customers, which are fair, just, and reasonable. *Id.*

The Commission notes that in DEC's annual fuel proceeding, DEC and the Public Staff agreed that DEC should continue to utilize the equal percentage fuel adjustment for purposes of that case. *See* Agreement and Stipulation of Partial Settlement, Docket No. E-7, Sub 1282 (filed May 31, 2023). The Commission further notes that there is not a similar agreement filed in the DEP annual fuel proceeding in Docket. No. E-2, Sub 1321.

Based on all the evidence in this proceeding, the Commission concludes that use of the equal percentage method of allocating fuel and fuel related costs does not follow the cost causation principle. In reaching this conclusion, the Commission gave substantial weight to the testimony of the Public Staff regarding the cost causation principle set forth in N.C.G.S. § 62-133.16, as well as their demonstration of the distortion that can be created by equal percentage fuel adjustments. Further, the Commission finds that this change shall be implemented for fuel rider proceedings filed after the date of this Order, and shall not apply in DEP's pending fuel adjustment proceeding, Docket No. E-2, Sub 1321.

Base Fuel and Fuel-Related Cost Factors

DEP's Application explained that the rates set forth in the exhibits to the Application included a base fuel and fuel-related rate of Residential - 2.126 cents per kWh; SGS - 2.111 cents per kWh; MGS 2.169 cents per kWh; LGS- 2.019 cents per kWh; and Lighting - 1.682 cents per kWh, excluding the Experience Modification Factors as approved in Docket No. E-2, Sub 1272 and excluding regulatory fees.

Witness Jiggetts testified DEP made an adjustment (Adjustment No. NC2010) to test period fuel expense to match the fuel clause revenues included in pro forma Adjustment No. NC1010. Tr. vol. 13, 180-81. She explained that by matching the expenses to the revenue, the adjustment ensures that no increase is requested in this proceeding related to fuel and fuel-related costs that are recoverable through the fuel clause. *Id*. She further stated that DEP intended to update this pro forma adjustment once it received an order in its pending fuel case in Docket No. E-2, Sub 1292. *Id.*

In her supplemental direct testimony, witness Jiggetts explained that DEP had updated pro forma Adjustment No. NC2010 to include revisions to reflect the fuel rates approved under in Docket No. E-2, Sub 1292. Tr. vol. 13, 221.

In her second supplemental direct testimony, witness Jiggetts testified that DEP had made a new adjustment (Adjustment No. NC2020 to adjust the nonfuel component of purchased power expense to reflect the impacts of the Stipulation Regarding the Proper Methodology for Determining the Fuel Costs Associated with Power Purchases from Power Marketers and Others reached with DEP, DEC and the Public Staff in Docket No. E-7, Sub 1282. Tr. vol. 13, 235. She further explained that during the test year, 39% of purchased power energy costs were estimated to be non-fuel expense and appropriate for cost recovery through base rates. *Id.* Based on the stipulation, during the test year, 15% of energy costs from these power purchases is the appropriate percentage to be deemed as non-fuel costs and appropriate for cost recovery through base rates. This pro forma adjustment makes the required reduction to operating expense in the test year as agreed upon with the Public Staff. *Id*.

The Commission issued a final order in the Sub 1292 fuel rider proceeding on November 3, 2022. In the Sub 1292 order, the Commission concluded that, effective for service rendered on and after December 1, 2022, DEP shall adjust the base fuel and fuel-related cost factors in its North Carolina retail rates, as approved in the 2019 Rate Case, amounting to 2.080¢/kWh for the Residential class, 2.126¢/kWh for the SGS class, 2.228¢/kWh for the MGS class, 2.204¢/kWh for the LGS class, and 1.392¢/kWh for the Lighting class (all excluding the regulatory fee), by amounts equal to 0.728¢/kWh, 0.971¢/kWh, 0.352¢/kWh, (0.066¢)/kWh and 1.984¢/kWh, respectively, and further, that DEP shall adjust the resulting approved prospective fuel and fuel-related cost factors by EMF increments/(decrements) of 0.649¢/kWh for the Residential class, 0.449¢/kWh for the SGS class, 0.586¢/kWh for the MGS class, 0.898¢/kWh for the LGS class, and 0.834¢/kWh for the Lighting class (excluding the regulatory fee). The Commission further

ordered that the EMF increments are to remain in effect for service rendered through November 30, 2023.

In the direct testimony of Public Staff witnesses Zhang and Boswell, they also used the fuel rates approved in Docket No. E-2, Sub 1292 to update revenues and expenses to May 2023 levels. Public Staff Accounting Ex. 1, Schedule 3-1(b)(1), Tr. Ex. vol. 19. In their Supplemental and Stipulation testimony they included an adjustment to fuel costs to reflect the impact of witness Lucas' recommendation to eliminate the equal percentage change in fuel rates. Tr. vol. 19, 91.

The only party that submitted evidence in this proceeding using fuel rates other than those approved in Docket No. E-2, Sub 1292 was the Public Staff. However, as shown on Public Staff Accounting Supplemental and Settlement Exhibit 1, Schedule 3-1(b), they adjusted fuel expense and revenue by the same amount so that there was no impact on the revenue requirement in this proceeding. *Id.* Also, Public Staff witness Lucas recommended that such rates be implemented effective December 1, 2023. No party offered any evidence contesting the testimony of witness Jiggetts that specifically supported the base fuel and fuel-related cost factor proposed by DEP. Accordingly, the Commission concludes for purposes of this proceeding that the total of the approved base fuel and fuel-related costs factors, by customer class — the sum of the respective base fuel and fuel-related costs factors set in the 2019 Rate Case and the annual non-EMF fuel and fuel-related costs riders approved by the Commission in Docket No. E-2, Sub 1292 — are just and reasonable to all parties in light of all the evidence presented.

Fuel Cost Allocations

In DEP's previous general rate case, the parties agreed on production plant as an appropriate allocation factor for purchased power capacity costs. Tr. vol. 11, 107. Under N.C.G.S. § 62-133.2(a2)(2), the Commission shall determine how these costs shall be allocated in a general rate case for the electric public utility. Therefore, this proceeding is the appropriate forum for the Commission to reconsider the appropriate cost allocation methodology for such costs, which are to be requested for cost recovery in DEP's annual fuel proceeding.

Witness Hager testified that DEP is proposing that the Commission use production demand as the more appropriate factor to allocate purchased power capacity costs to North Carolina retail and across North Carolina retail customer classes. Tr. vol. 11, 107. She testified that allocation based on production demand is more appropriate than production plant because purchased power capacity costs that are not recovered through the fuel clause are allocated on production demand. *Id.* She testified that the change towards allocation based on production demand would align all purchased capacity costs under the same allocator. *Id.* Additionally, most production plant is allocated on production demand, except for jurisdiction-specific amounts that are not related to purchase power costs. *Id.*

No party offered testimony opposing DEP's recommendation.

In DEP's previous general rate case, the parties agreed on production plant as an appropriate allocation factor for purchased power capacity costs. Tr. vol. 11, 107. Under N.C.G.S. § 62-133.2(a2)(2), the Commission shall determine how these costs shall be allocated in a general rate case for the electric public utility. Therefore, this proceeding is the appropriate forum for the Commission to reconsider the appropriate cost allocation methodology for such costs, which are to be requested for cost recovery in DEP's annual fuel proceeding. Based upon the evidence presented in this case, the Commission finds and concludes that the same production demand allocation method approved for production demand costs in this case using the 12 CP methodology at NC retail and the Modified A&E methodology for NC retail classes is the most appropriate methodology for allocating purchased power capacity costs in DEP's annual fuel proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 76-77

Residential Decoupling Mechanism and Earnings Sharing Mechanism

The evidence supporting these findings of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Abernathy, Bateman and Stillman, Public Staff witnesses D. Williamson and Thomas, AGO witness Nelson, and the entire record in this proceeding.

Summary of Evidence

DEP's PBR Application seeks approval of performance-based regulation through the proposed three-year MYRP beginning on October 1, 2023 and ending September 30, 2026. DEP witness Bateman testified that in addition to the three-year MYRP, which includes an ESM, DEP's PBR Application also includes PIMs a decoupling mechanism for the residential customer class. Tr. vol. 14, 76. Witness Bateman explained that the PBR approach and DEP's PBR Application better aligns customer and state policy goals with utility revenues and performance than traditional ratemaking. *Id.* at 80.

Residential Decoupling Mechanism

DEP witness Abernathy provided direct testimony on the proposed decoupling mechanism. She testified that the "decoupling rate-making mechanism" is intended to break the link between an electric public utility's revenue and the level of consumption of electricity on a per customer basis. She explained that the following Rate Schedules are affected by the decoupling mechanism: RES, R-TOU, R-TOUD, and R-TOU-CPP, along with any new residential rate schedules approved by the Commission during the Plan Period. She testified that the Residential Energy Conservation Discount Rider is also impacted by decoupling. She testified as to how the annual and monthly target revenue per customer would be calculated for Rate Years 1, 2 and 3. She also testified as to estimated number of residential customers for each year and for each month for each rate year. She also explained that the difference between target residential revenues and actual residential revenues would be deferred, which would be adjusted to account for DSM/EE net lost revenues and incremental EV revenues. She also explained how the

carrying cost on the deferral would be calculated. She explained how the Decoupling Rider will work and DEP's reporting obligations with respect to the deferred balance. Tr. vol. 13, 102-12.

AGO witness Nelson also supported using a lower carrying cost rate on the decoupling deferral amount and placing a hard cap of 3% on surcharges. Tr. vol. 18, 82-83. Witness Nelson explained that a hard cap would limit rate increases and promote cost containment. *Id*. at 84.

The Public Staff expressed only one concern regarding DEP's proposed decoupling mechanism. Public Staff witness Nader testified that N.C.G.S. § 62-133.16 authorizes the Commission to approve a residential decoupling mechanism designed to break the link between revenues and the consumption of electricity. Witness Nader also testified that the statute also the utility with an opportunity to exclude rate schedules or riders associated with EV charging from sales calculations for purposes of the mechanism. Tr. vol. 21, 110-11. Witness Nader objected to how DEP determined the estimate of EV sales for the calculation and recommended that the decoupling mechanism not include DEP's proposed "Incremental EV Revenue Adjustment". *Id.* Witness Nader asserted that the estimate was "highly speculative" and that the decoupling mechanism should only include the adjustment for EV sales when more accurate EV sales data are available. *Id.* He recommended that DEP use a lower kWh per EV estimate than DEP proposed initially.

AGO witness Nelson asserted that DEP's proposal to exclude EV sales from its decoupling mechanism is not in the public interest. Tr. vol. 18, 72-73. Witness Nelson asserted that there is no link between this proposal and the goal of advancing EV adoption. *Id.* at 74. Witness Nelson further stated that the calculation for EV sales is not accurate and recommended that the Commission reject DEP's proposal. *Id.* at 79.

DoD-FEA witness Blank recommended that the Commission deny DEP's proposal to remove EV sales from the ESM. Tr. vol. 21, 34. Witness Blank stated that the PBR Statute explicitly provides what a utility can exclude from the ESM calculation, and the statute does not list EV sales. Tr. vol. 21, 341.

In response to AGO witness Nelson's suggestion to institute a 3% hard cap on the amounts the utility is able to collect from customers, "decoupling cap," witness Abernathy testified that there is no basis for a cap in the statute, that a cap has only been authorized in a few states, and that there is no cap on the recovery of DSM/EE net lost revenues. Tr. vol. 23, 149-50. Witness Bateman's rebuttal testimony offered further support for the exclusion of EV sales from the decoupling mechanism. Tr. vol. 23, 161-62. Witness Bateman testified that adjusting the decoupling mechanism for EV sales allows the utility to retain incremental net revenues driven by EV growth, thereby directly connecting EV growth with net revenues. Witness Bateman explained that if the Commission precluded DEP from including an EV adjustment within the decoupling and ESM calculations, DEP's residential EV sales would be decoupled from the utility's margin, thus eliminating an

important incentive for the utility to encourage EV adoption and grow EV sales in between rate case filings. *Id.*

The PIMs Stipulation provides that the parties thereto agree to allow DEP to exclude all EV sales from the decoupling mechanism subject to the following two conditions: (1) that the parties work together to develop and file EV tariffs and/or programs to estimate and update the revenue associated with residential EV sales in DEP's service territory, within 90 days of the Commission's order in this docket, and (2) that DEP updates the kWh per EV estimate proposed by Public Staff witness Nader with actual, DEP-specific EV usage data in each future decoupling rider proceeding.

Witness Bateman explained that the PIMs Stipulation clarified how DEP will obtain data that will help it to better estimate revenue associated with incremental residential EVs. Tr. vol. 14, 155. Witness Bateman explained that the agreed-upon method entails using DOT data to derive the number of residential EVs in DEP's service territory, using 180 kWh per vehicle as the electric usage (a value DEP measured within the EV Make-Ready Program), and then applying the flat residential tariff rate to the average monthly EV usage amount to derive the amount of residential EV sales to exclude from the decoupling mechanism. Tr. vol. 23, 234. Thereafter, within 90 days of a Commission order in this proceeding, DEP will file tariffs or programs, and using the data from those tariffs and programs, will refine the analytics to update the number of EVs and the usage assigned to each vehicle. *Id.* at 233. Witness Bateman also stated that DEP will also use this agreed-upon method to exclude EV sales from the ESM. *Id*. at 234-35.

Earnings Sharing Mechanism

DEP witnesses Abernathy and Bateman testified in support of the ESM, which is a component of the MYRP. Tr. vol. 13, 112; Tr. vol. 14, 81. Witness Abernathy explained that if DEP's adjusted earnings exceed the authorized ROE established by the Commission in this rate case plus 50 basis points, those excess earnings, including a return calculated at the weighted average cost of capital, must be distributed to customers over a 12-month period via the annual ESM Rider. Tr. vol. 13, 112.

Witness Abernathy testified that, for purposes of the ESM calculation, DEP will adjust earnings for weather, DSM/EE incentives, PIMs, and EV sales. Tr. vol. 13, 113.

Witness Bateman that the ESM allocates risk away from customers and onto DEP, noting how the ESM distributes to customers 100% of earnings in excess of 50 basis points above the authorized ROE on an annual basis, without a corresponding ability for DEP to collect additional revenue from customers if the utility is underearning. Tr. vol. 14, 81.

Also, as noted above, witness Bateman explained that if the Commission precluded DEP from including an EV adjustment within the ESM calculations, DEP's residential EV sales would be decoupled from the utility's margin, thus eliminating an important incentive for the utility to encourage EV adoption and grow EV sales in between rate case filings.

During the expert witness hearing DEP witness Stillman also provided support for DEP's proposal to exclude EV sales from the ESM where he stated that the adjustment would further support the increased adoption of EVs. Tr. vol. 13, 151. Witness Bateman further explained that this is consistent with the policy goals in N.C.G.S. § 62-133, Commission Rules R1-17B(g)(1)(f) and R1-17B(g)(2), and Governor Cooper's Executive Order 246. *Id.* at 162.

In response to Commission questions, DEP witness Jiggetts, noted that the reports DEP currently files to show annualized return on equity for each quarter is a very high level report. Tr. vol. 13, 327. Currently, DEP provides the Commission with a quarterly surveillance report, the ES1, that shows the Commission approximately where DEP's earnings are as compared to what it is allowed to earn. Tr. vol. 13, 324. Witness Jiggetts explained that in preparing that report, DEP makes numerous simplifying assumptions in order to be able to provide the report to the Commission within the required timeframe. *Id.* Witness Jiggetts confirmed that the quarterly surveillance reports provide a "snapshot" at a high level that does not include several ratemaking adjustments that would be necessary to arrive at DEP's actual return on rate base. *Id.* at 327. DEP provides qualifying language in the quarterly reports indicating that the figures do not accurately reflect DEP's earnings. *Id.* at 329.

Commissioner Clodfelter followed up with witness Jiggetts by asking how the Commission and the Public Staff can obtain actual annualized historical returns on equity that DEP has achieved, not for ratemaking purposes. Tr. vol. 14, 35. Witness Jiggetts explained that to reach a figure that represents DEP's true earnings, the Commission would need to ask DEP to do more detailed reporting and make certain adjustments to reflect the expected ongoing earnings, rather than using the high-level assumptions DEP employs for the quarterly ES1 reports. *Id.* at 35-36. Commissioner Clodfelter noted that the Commission, in evaluating the ESM Rider, needs to know a baseline number of what DEP actually earned in order to determine whether DEP over-earned or under-earned, or whether the Commission should increase or decrease the rate of return, or leave it the same. *Id.* at 37.

Discussion and Conclusion

In general, the Commission concludes that the residential decoupling mechanism and the ESM proposed by DEP are consistent with the PBR Statute and with Commission rule. Further, the Commission concludes that DEP's proposal to exclude EV sales from the decoupling mechanism and the ESM, as modified by the PIMs Stipulation, is reasonable and should be approved. The Commission does not find it appropriate, for the reasons advanced by DEP witnesses Bateman and Abernathy, to impose a decoupling cap, or authorize a lower carrying cost on the decoupling deferral amount. The Commission notes that the TCA Stipulation provides that the $20 million adjustment in the revenue requirement agreed to in the stipulation will be included in the ESM for DEP.

The Commission notes that the current ES1 reports were not intended to be used as a method to evaluate the ESM Rider. The Commission further notes that Commission

Rule R1-17B(h)(1) provides for the filing of quarterly earnings reports that require certain enumerated information. The Commission directs DEP to work with the Public Staff to develop a quarterly reporting form for DEP's earnings that will enable the Commission to analyze the information and determine the appropriate application and operation of the ESM Rider. As part of this review, DEP and the Public Staff shall review the requirements of Commission Rule R1-17B(h)(1) and recommend any necessary changes.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 78

Performance Based Regulation

The evidence supporting this finding of fact is contained in DEP's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Abernathy, Bateman and Stillman, Public Staff witnesses D. Williamson and Thomas, AGO witness Nelson, and CUCA witness O'Donnell; and the entire record in this proceeding.

Summary of Evidence

DEP's PBR Application seeks approval of performance-based regulation through the proposed three-year MYRP beginning on October 1, 2023, and ending September 30, 2026. DEP witness Bateman testified that in addition to the three-year MYRP, which includes an ESM, DEP's PBR Application includes a residential decoupling mechanism, PIMs, and tracking metrics. Tr. vol. 14, 76. Witness Bateman explained that the PBR approach, in general, and DEP's proposed MYRP better aligns customer and state policy goals with utility revenues and performance than does traditional ratemaking. *Id.* at 80.

The Commission notes, as the Public Staff points out, that the PBR Statute represents a substantial supplement to the existing law related to electric public utilities, such as DEP, and provides DEP with a cost recovery framework that represents fairly significant departure from the traditional cost recovery paradigm that has served North Carolina's electric utilities and their customers well for many decades. Discussed below are four new concepts allowed for the first time in North Carolina under the PBR Statute.

First, electric public utilities in North Carolina are entitled to file a MYRP, which is "a rate-making mechanism under which the Commission sets base rates for a multiyear period that includes authorized periodic changes in base rates without the need for the electric public utility to file a subsequent general rate application …" N.C.G.S. § 62-133.16(a)(5). This approach is a departure from the adjusted historic test year and authorizes certain projections of cost in the setting of rates.

Second, electric public utilities, such as DEP, are now allowed to utilize a decoupling mechanism. Under the PBR Statute's decoupling mechanism, DEP is authorized to "defer to a regulatory asset or liability account the difference between the actual revenue and the target revenue for the residential class" and this variance will result in an annual adjustment to the residential customer classes' bills. N.C.G.S. § 62-133.16(c)(2).

Third, the PBR Statute creates an ESM, which allows the electric public utility to elect to file a new rate case under N.C.G.S. § 62-133 in the event its weather-normalized earnings fall below the authorized rate of return on equity and requires the utility to refund to customers all weather-normalized earnings in excess of the authorized rate of return plus 50 basis points. N.C.G.S. § 62-133.16(c)(1).

Fourth, the PBR Statute requires that the utility implement at least one performance incentive mechanism, which is "a rate-making mechanism that links electric public utility revenue or earnings to utility performance in target areas consistent with policy goals …" N.C.G.S. § 62-133.16(a)(6). PIMs are intended to encourage the types of behavior about which customers care, provide DEP with the opportunity to earn a reward to be collected from customers, and expose DEP to payment of penalties which are refunded to customers (subject to a cap). N.C.G.S. § 62-133.16(c)(4).

While certain of the mechanisms established in the PBR Statute are new to North Carolina, aspects of the law are familiar and well-known to the Commission. For example, the responsibility "[t]o make reasonable and just rates" has been the obligation of the Commission's predecessors since the 19th century. *See, e.g.*, 1899 N.C. Session Laws, Chapter 164, § 2. The requirement that rates be "fair both to the electric public utility and to the customer," set forth in N.C.G.S. § 62-133.16(d)(1)(a) mirrors the charge in N.C.G.S. § 62-133(a) that "the Commission shall fix such rates as shall be fair both to the public utilities and to the consumer." Moreover, N.C.G.S. § 62.133-16 explicitly preserves the Commission's existing rate-making authority, providing: "[n]othing in this section shall be construed to [ ] limit or abrogate the existing rate-making authority of the Commission …" N.C.G.S. § 62-133.16(g) (omission denoted via brackets and ellipses). And, significantly, the Commission has long been required to consider risks both to the electric utility and to its customers, as it is well-established policy in North Carolina "to provide fair regulation of public utilities in the interest of the public" as well as "to promote adequate, reliable and economical utility service to all of the citizens and residents of the State." N.C.G.S. § 62-2(1), (3).

When reviewing a PBR application, the PBR Statute requires the Commission must consider whether a PBR application:

a. Assures that no customer or class of customers is unreasonably harmed and that the rates are fair both to the electric public utility and to the customer.

b. Reasonably assures the continuation of safe and reliable electric service.

c. Will not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or "rate shock" to customers.

N.C.G.S. § 62-133.16(d)(1).

Elsewhere in this Order the Commission has ruled upon the specific requests of DEP regarding costs to be recovered, as well as the rate of return that DEP has an opportunity to earn. In approving costs for recovery and establishing the rate of return, the Commission has applied well-established law in attempt to put the utility in a position to maintain its system and level of service, in view of the very real challenges that lie ahead for DEP, to earn a fair return, in view of current economic conditions, and to compete in the marketplace for capital on reasonable terms and at times when a capital need arises. The Commission has considered the impact of changing economic conditions on customers, recognizing that certain of the utility's customers will struggle to afford electric utility service, and has endeavored to establish rates that achieve the foregoing objectives most economically. In addition, elsewhere in this Order, the Commission has considered the potential for prejudice to customer classes and accepts the cost allocation methods, as well as certain of the rate designs, proposed by the utility and modified by the various stipulations to be reasonable and not prejudicial to any customer class.

In addition to the requirements for consideration by the Commission set forth in N.C.G.S. § 62-133.16(d)(1), the PBR Statute provides guidance on other considerations the Commission may undertake, including, for example, whether the PBR application "reduces low-income energy burdens;" whether the PBR application "encourages DERs"; whether the PBR application "encourages utility-scale renewable energy and storage"; and whether the PBR application "encourages peak load reduction or efficient use of the system." N.C.G.S. § 62-133.16(d)(2). The Commission notes, for example, that the PIMs Stipulation, discussed in detail elsewhere in this Order, involves PIMs that are intended to increase numbers of customers enrolled in time-differentiated rates, to increase the number of net-metered interconnections, to encourage the interconnection of utility scale generation above DEP's estimated annual limits, and to enable large commercial and industrial customers to achieve clean/carbon free energy objectives. Each of these PIMs aligns with the considerations established in N.C.G.S. § 62-133.16(d)(2). The tracking metrics, agreed upon by the parties to the PIMs Stipulation, pertain to customer service, reliability and "beneficial electrification," all of which should inform the future development of PIMs that align with the guidance set forth in N.C.G.S. § 62-133.16(d)(2). In addition, elsewhere in this Order, the Commission discusses the CAP's proposed by DEP in this proceeding, aimed at proving customers in need of assistance with bill payment, as well as the Affordability Stipulation, which is intended to provide additional relief for customers who will struggle to afford the cost of electricity. These provisions of the PBR Application, as modified by the stipulations, align with the considerations of § 62-133.16(d)(2). Throughout the course of this proceeding, DEP has worked with parties to the proceeding to refine the elements of its PBR Application to better conform to the requirements of N.C.G.S. § 62-133.16(d)(1) and to more closely align with the guidance set forth in N.C.G.S. § 62-133.16(d)(2).

The PBR Statute provides that the Commission is authorized to approve a utility's PBR application "so long as the Commission allocates the electric public utility's total revenue requirement among customer classes based upon the cost causation principle . . . and interclass subsidization of ratepayers is minimized to the greatest extent

practicable by the conclusion of the MYRP period." N.C.G.S. § 62-133.16(b). As previously explained, the PBR Statute also requires that the Commission consider whether a PBR application: 1) assures that no customer or class of customers be unreasonably harmed and that the rates are fair both to the electric public utility and to the customer; 2) reasonably assures the continuation of safe and reliable electric service; and 3) will not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or "rate shock" to customers. N.C.G.S. § 62-133.16(d). During cross-examination by CIGFUR II, DEP witness Reed acknowledged that the PBR Statute requires DEP to minimize interclass subsidization. Tr. vol. 11, 330. However, witness Reed emphasized that the PBR Statute requires the minimization of interclass subsidization "to the greatest extent practicable," which, the Commission concludes, DEP has achieved. The Commission concludes that DEP's approach of gradually reducing the subsidies between classes by utilizing a variance reduction of 10% is reasonable and that the 10% variance reduction approach moves towards eventual rate parity/minimization of interclass subsidization while, at the same time, balancing the other requirements of the PBR Statute including that no class of customer is unreasonably harmed or faces a sudden and substantial increase in rates resulting in rate shock. The Commission agrees with DEP witness Reed who testified that DEP appropriately considered "competing priorities" such as cost causation, rate shock, and gradualism in proposing the 10% variance reduction. Tr. vol. 11, 320-21. The Commission does not agree with the recommendation of CIGFUR II witness Phillips' argument that a greater variance reduction is warranted in this proceeding, primarily in light of the harm that such a reduction would cause to certain customer classes. Specifically, DEP witness Reed explained that if DEP had employed a 25% subsidy reduction, as recommended by CIGFUR II witness Phillips, the proposed increase to the Residential class would increase from 9.9% to 10.4% and the proposed increase to the Lighting class would increase from 19.9% to 24.9%. Tr. vol. 11, 265. Thus, balancing its obligations under the PBR Statute to ensure allocation of revenue requirement based on cost causation, minimization of interclass subsidization, equitable treatment of customer classes, and avoidance of unreasonable prejudice and rate shock, the Commission concludes that DEP's PBR Application as amended by the stipulations and the various provisions of this Order, is in alignment with cost causation or reasonably headed that way, avoids unreasonable harm to any class of customers, and does not unreasonably prejudice an class of customers or otherwise result in rate shock.

For the foregoing reasons, and as discussed in greater detail throughout this Order, the Commission concludes that DEP's PBR Application, as modified by the stipulations and this Order, results in just and reasonable rates, is in the public interest, and is consistent with the criteria established in N.C.G.S. § 62-133.16.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 79

Revenue Requirement

The evidence supporting this finding of fact is found in DEP's verified Application and Form E-1; the Revenue Requirement Stipulation; the TCA Stipulation; and the

Supplemental Revenue Requirement Stipulation; the testimony and exhibits of the witnesses, including DEP witness Jiggetts and Abernathy and Public Staff witness Zhang and Boswell; and the entire record in this proceeding.

The Revenue Requirement Stipulation, the TCA Stipulation, and the Supplemental Revenue Requirement Stipulation provide for certain accounting adjustments that parties have agreed upon and the Commission has approved in this Order. The stipulation issues that impact the revenue requirement in the Revenue Requirement Stipulation and the TCA Stipulation are detailed in in Jiggetts Partial Settlement Exhibit 2 (Tr. Ex. vol, 14) and the Public Staff Accounting Supplemental and Settlement Exhibit 1 Schedule 1 (Tr. Ex. vol 19), which provide sufficient support for the annual revenue required on the issues agreed to in the Revenue Requirement Stipulation. The stipulation issues that impact the revenue requirement in the Supplemental Revenue Requirement Stipulation are in the Supplemental Revenue Requirement Stipulation Exhibit 1 (Tr. Ex. vol 7).

After giving effect to the approved stipulations and the Commission's decisions on the Unresolved Issues, as discussed herein, the Commission finds that DEP should recalculate the required annual revenue requirement consistent with the Commission's findings herein withing 10 days of the issuance of this Order. DEP is further directed to file with the Commission the final revenue requirements for Rate Years 1, 2, and 3 in the same format as Jiggetts Partial Settlement Exhibit 1. The Commission directs DEP to work with the Public Staff to verify the accuracy of the calculations, and the filing should reflect the corrections identified by DEP and agreed upon by the Public Staff.

The Commission concludes the annual revenue requirement for DEP for Rate Years 1, 2, and 3 which reflect the approved stipulations and the Commission's decisions on the Unresolved Issues will allow DEP a reasonable opportunity to recover its operating costs and earn the overall rate of return on its rate base that the Commission has found just and reasonable upon consideration of the findings in this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the Revenue Requirement Stipulation, the COSS Stipulation, the TCA Stipulation, the PIMs Stipulation, the Affordability Stipulation, the MGS Partial Rate Design Stipulation, the LGS Partial Rate Design Stipulation, and the Supplemental Revenue Requirement Stipulation are accepted and approved, as detailed in this Order. The Power Quality Stipulation is not approved as detailed in this Order;

2. That the depreciation rates proposed by DEP in this case, which are based on the 2021 Depreciation Study and amended by the Revenue Requirement Stipulation, with such agreed upon amendments proposed by the Public Staff including the amortization periods for General Plant accounts 391 and 397, and the 70-year life of Transmission FERC account 356, shall be, and is hereby approved;

3. That DEP's request for an accounting order for approval to defer to a regulatory asset 75% of the impact of accelerating the retirement of DEP's Mayo and

Roxboro Units 3 and 4, as agreed upon in the Revenue Requirement Stipulation, preserving DEP's ability to recover 50% of the net book value of the subcritical plants through securitization, shall be, and is hereby approved;

4. That the remaining net book value of DEP's Mayo and Roxboro Units 3 and 4 at retirement shall be recovered with a return over the amortization period determined by the Commission in a future rate case;

5. DEP's plant-related capital investments in the base period fossil, renewable, storage, and nuclear fleet assets as adjusted in the Revenue Requirement Stipulation, shall be included in rates for the base period;

6. DEP's transmission and distribution investments made during the test period, as adjusted by the Revenue Requirement Stipulation, shall be included in rates for the base period;

7. That DEP's GIP investments shall be included for recovery in DEP's rates;

8. That in accordance with the Revenue Requirement Stipulation, DEP is permitted to recover the full balance of its GIP deferral over an 18-year amortization period, with a debt-only return during the deferral period and rate base treatment during the 18-year amortization period;

9. That DEP shall recover the balance of the CCR deferral, net of the over amortization, over a five-year amortization period with reduced financing costs during the amortization period calculated based on (1) DEP's cost of debt as approved in this Order adjusted as appropriate to reflect the deductibility of interest expense, (2) an ROE 150 basis points lower than the 9.8% ROE as approved in this Order, and (3) a capital structure of 48% debt and 52% equity as set forth in the CCR Settlement;

10. That in accordance with the Revenue Requirement Stipulation, DEP shall flowback to customers over a three-year period the liability related to the gains on Harris land sales;

11. That in accordance with the Revenue Requirement Stipulation, DEP shall continue to defer any gains on any future Harris land sales to return to customers in a future general rate case;

12. That DEP shall amortize the Roxboro Wastewater Treatment Facility regulatory asset over a period of twelve years and the unamortized balance shall be included in rate base;

13. That DEP shall amortize the regulatory liability for overcollections associated with storm securitization over a three-year period;

14. That the agreed-upon accounting adjustments outlined in the Revenue

Requirement Stipulation shall be, and are hereby, approved;

15. That DEP shall track and report on an annual basis the actual spend and employee head count for each coal generation station over the MYRP period in a manner to be agreed upon by DEP and the Public Staff. DEP shall update the Commission on the manner upon which DEP and the Public Staff have agreed to the tracking and reporting of the actual spend and employee head count for each coal generation station;

16. That DEP shall record any cumulative underspend less than $6 million (North Carolina retail) of annual incremental spend for ongoing O&M for DEP's coal generation fleet for discrete programs and targeted categories to a regulatory liability account accrued through the end of the MYRP period (September 2026) and return the underspend to customers in the next general rate case;

17. That DEP shall perform a lead-lag study before its next general rate proceeding and incorporate the results of that study in its next general rate case filing;

18. That DEP's proposed MYRP, reflecting the projected costs associated with the Transmission, Distribution, Fossil/Hydro, Nuclear, Cybersecurity, Solar, and Storage capital investments, as adjusted by the Revenue Requirement Stipulation, as reflected in Abernathy Partial Settlement Exhibits 1 and 2, is just and reasonable and adopted in its entirety;

19. That DEP has demonstrated a reasonable plan to timely complete the MYRP projects;

20. That DEP shall consult with the Public Staff to develop a report on Rider EC. DEP shall file its first report on Rider EC no later than one year from the date of this Order;

21. That DEP shall report on the issue of CIAC related to IAs in its next rate case application;

22. That DEP shall consult with the Public Staff to develop a report on reliability O&M as the Public Staff proposed. DEP shall file its first report on reliability O&M no later than one year from the date of this Order;

23. That DEP shall consult with the Public Staff to develop its Vegetation Management Program Performance report as provided in this Order;

24. DEP shall, in consultation with the Public Staff, file a report on the Hot Springs Cost Benefit Analysis;

25. That DEP may to recover through base rates DEP's costs associated with its DSDR program;

26. That DEP's request to establish the Payment Navigator program shall be, and is hereby approved;

27. That DEP shall be allowed to recover its costs to implement Customer Connect;

28. That the COSS Stipulation shall be, and is hereby approved;

29. That in its next general rate case, DEP shall provide a comprehensive justification for the use of a NCP demand instead of a coincident peak demand for any cost allocation purpose;

30. That the PIMs Stipulation is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B, achieves a measured balance between encouraging behavior and risk/reward to utility shall be, and is hereby approved;

31. That the Power Quality Stipulation, or the pilot program addressed therein, are not approved, but that DEP may file an application for such a pilot program in a separate proceeding;

32. That, consistent with the Affordability Stipulation, DEP's proposed CAP is hereby approved as a three-year pilot;

33. That DEP's proposed CAP and CAR Riders shall be, and is hereby approved;

34. That the shareholder financial contributions, detailed in the Affordability Stipulation, shall be, and is hereby approved;

35.; That DEP shall convene a stakeholder group to meet at least quarterly to consider data and reporting issues related to the CAP. The stakeholder group is directed to develop an annual report on the CAP as provided in this Order;

36. DEP is directed to file a report on the feasibility and proposed structure of a tiered customer assistance program the later of (i) 18 months after the date of this Order, or (ii) when there is one year of data from the CAP Rider;

37. DEP is directed to report on the Affordability Metrics established in this Order in the same manner as it reports on the tracking metrics agreed to in the PIMS Stipulation;

38. That DEP shall consult with the Public Staff to develop a report on the CAP including the number of CAP recipients, CAP administration costs, and the observed impacts of CAP on arrearage management and disconnections for nonpayment;

39. That the revisions to rate schedules, as proposed by DEP or as otherwise modified herein shall be, and is hereby approved;

40. That the revisions to the service riders, as proposed by DEP or otherwise specifically modified herein, including Rider EC and Rider NSC shall be, and is hereby approved;

41. DEP shall notify all SGS customers that customers may now elect the residential rate schedule for detached garages, barns, and other structures on the same residential premise currently served under a residential rate schedule;

42. That DEP shall inform all Schedule SLR customers that the schedule will not be open to new customers as of October 1, 2023;

43. That DEP shall provide via bill insert or separate mailing amendments to its Outdoor Lighting Service Regulations to all customers subject to those Regulations;

44. That DEP shall, before the next rate case, analyze the impacts of transferring customers receiving service under Riders 7 and 57 to other standby service riders and, if that analysis reveals viable options for transferring these customers, DEP shall propose a transition period in its next general rate case to move these customers to other standby service riders over a reasonable period and in a manner that lessens or avoids rate shock;

45. That DEP's rates during the MYRP Rate Period shall reflect a rate of return on equity of 9.8% and embedded cost of debt of 4.03% based on a capital structure consisting of 53% common equity and 47% long-term, for a rate of return of 7.09%;

46. That DEP's shall be allowed to recover certain COVID-related costs that have been deferred, including customer fees waived, bad debt charge-offs, and costs related to employee safety, netted against the COVID-related savings related to printing, postage, employee travel, and certain measures taken by the federal government that benefitted DEP during the pandemic, over a six-year period with no return on the unamortized balance during the amortization period, which shall begin on the effective date of the rates approved in this proceeding;

47. That DEP's request to continue the deferral of bad debt expenses related to the impact of the COVID-19 pandemic is hereby approved. That any payments associated with bad debt amounts should be credited on a monthly basis through the next general rate case proceeding. That DEP should report on a semiannual basis the actual amounts recorded to the deferral and the payments received;

48. That the inflation adjustment proposed by DEP shall be, and is hereby approved;

49. That DEP's request to recover costs incurred related to the Commission's Order in the 2019 Rate Case in the amount of $5.384 million, which are above and beyond the rate case costs provided for in the 2019 First Partial Settlement is hereby approved. Such costs shall be amortized over a three-year period;

50. That DEP is hereby allowed to recover over a three-year period rate case costs in the amount of $6.551 million related to the present proceeding;

51. That DEP's request to include the unamortized balance of rate case expense in rate base shall be, and is hereby denied;

52. That DEP's request to track actual rate case costs from the March 31, 2023 update cutoff date in this proceeding through the date rates become effective for possible recovery in a future rate case proceeding shall be, and is hereby denied;

53. That the following treatment with respect to over-amortizations of regulatory assets shall be, and hereby is approved for purposes of this proceeding:

a. The over-amortization of rate case expense from Docket No. E-2, Sub 1023 of $1,112,000 should be applied to the balance of rate case expense from the Commission's Order in the 2017 Rate Case of $530,000, which will eliminate that balance. The remaining $582,000 of over-amortization should be applied against rate case costs being requested in this proceeding.

b. The over-amortization of severance costs from the Commisioner's Order in the 2019 Rate Case in the amount of $907,000 should not be applied against the rate case costs being requested in this proceeding but instead should be refunded to customers through a one-year rider with interest.

c. The over-amortization of early retired plant in the amount of $13.8 million should be applied against the outstanding rate base balance for the Asheville early retired coal plant authorized in the 2019 Rate Case.

d. The over-amortization of Hurricane Matthew costs from the Commission's Order in the 2017 Rate Case in the amount of $17 million should be treated as follows: first, to recover 2022 incremental Winter Storm Izzy costs, and second, the remaining $2 million credit should be refunded to customers through a one-year rider with interest.

e. Over-amortization of regulatory fees in the amount of $68 thousand should be refunded to customers through a one-year rider with interest.

54. That if DEP receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, DEP shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until DEP's next general rate case for a determination of the appropriate ratemaking treatment of such over-amortizations;

55. That DEP is allowed to collect in rates its North Carolina Retail normalized annual level of storm costs in the amount of approximately $22.2 million;

56. That DEP's request for an accounting order for approval to establish a regulatory asset to defer the incremental costs incurred as a result of Winter Storm Izzy shall be, and hereby is approved;

57. That DEP shall be allowed to recover the 2022 incremental Winter Storm Izzy costs of approximately $15 million applying a portion of the over-amortization of Hurricane Matthew costs in the amount of $17 million from the Commission's Order in the 2017 Rate Case;

58. That the remaining amount of over-amortization of Hurricane Matthew costs of approximately $2.0 million, shall be returned to customers through a levelized rider over a period of one year;

59. That DEP's request for an accounting order for the storm balancing account shall be, and is hereby denied;

60. That DEP's request for an accounting order to defer any incremental revenue requirement impacts, including benefits and costs, associated with the IRA and the IIJA, shall be, and is hereby approved;

61. That DEP's request for an accounting order to defer implementation and administration costs associated with the CAP, Payment Navigator Program, and the Tariffed On-Bill program, and PIMs, shall be, and is hereby denied;

62. That the establishment of a regulatory liability as recommended by the Public Staff to address CIAC collected by DEP related to interconnection agreements is not warranted at this time, however, DEP shall report on the issue of how CIAC is recorded in the context of interconnection agreements in its next general rate case application as required by the Revenue Requirement Stipulation;

63. That the Commission finds DEP's provision of electric service to be adequate;

64. That DEP's proposed revisions to its previously approved North Carolina excess EDIT rider (EDIT-4) to reflect additional amounts due to customers, shall be, and is hereby approved, and that the leveled return rate shall be based on a capital structure consisting of 47% long-term debt and 53% equity, an embedded cost of debt of 4.03% and a rate of return on equity of 9.8%;

65. That DEP shall use the base fuel rates, exclusive of the equal percentage allocation, established above in the current (2023) annual fuel adjustment proceeding;

66. That the approved base fuel and fuel-related cost factors by customer class are as follows: 2.808 cents/kWh for the Residential class, 3.097 cents/kWh for the SGS class, 2.580 cents/kWh for the MGS class, 2.138 cents/kWh for the LGS class, and 3.376 cents/kWh for the Lighting class;

67. The production demand allocation method approved for production demand costs using the 12 CP method at NC retail and the modified A&E method for NC retail classes is the most appropriate method for allocating purchased power capacity costs in DEP's annual fuel proceedings;

68. That DEP's proposed residential decoupling mechanism is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B, and the proposed tariff for the associated rider, shall be, and is hereby approved;

69. That DEP's proposed ESM, as modified by the TCA Stipulation, is consistent with N.C.G.S. § 62-133.16 and Commission Rule R1-17B, and the proposed tariff for the associated rider, shall be, and is hereby approved;

70. That DEP shall file the final annual revenue requirements for Rate Years 1, 2, and 3 consistent with the Commission's findings and rulings herein within 10 days of the issuance of this Order in the same format as Jiggetts Partial Settlement Exhibit 1. DEP shall work with the Public Staff to verify the accuracy of the calculations;

71. DEP shall file schedules (North Carolina Retail Operations – Statement of Rate Base and Rate of Return, Statement of Operating Income, and Statement of Capitalization and Related Costs) with the Commission within 10 days of the issuance of this Order, summarizing the gross revenue and the rate of return that DEP should have the opportunity to achieve based on the Commission's findings and determination in this proceeding;

72. That DEP is authorized to adjust its rates and charges in accordance with the Revenue Requirement Stipulation, the TCA Stipulation, and the Supplemental Revenue Requirement Stipulation and findings in this Order effective for service rendered on and after the following date after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 70;

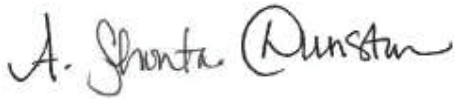
73. That within 30 days of this Order, DEP shall file for Commission approval all rate schedules designed to comply with this Order, accompanied by calculations showing the revenues that will be produced by the rates for each schedule; and

74. That DEP shall submit a proposed customer notice to the Commission for review and approval, and upon approval of the notice by the Commission, shall give appropriate notice of the approved rate increase by mailing the notice to each of its North Carolina retail customers during the billing cycle following the effective date of the new rates.

ISSUED BY ORDER OF THE COMMISSION.

This the 18th day of August, 2023.

NORTH CAROLINA UTILITIES COMMISSION



A. Shonta Dunston, Chief Clerk

Chair Charlotte A. Mitchell dissents in part. Commissioner Kimberly W. Duffley joins in Chair Mitchell's dissent in full. Commissioner Karen M. Kemerait joins in Chair's Mitchell's dissent with respect to the sections on rate of return of equity and the recovery of the deferred COVID-related costs.

Commissioner Daniel G. Clodfelter dissents in part and concurs in part.

DOCKET NO. E-2, SUB 1300

Chair Charlotte A. Mitchell, dissenting in part:

For the reasons set forth below, I dissent from the Order's resolution of the following three issues: rate of return on equity, the recovery of deferred COVID-related costs, and affordability – next steps.

I. Rate of Return on Equity

DEP requested a rate of return on equity (ROE) of 10.4%, and DEP witness Morin testified on cross examination that, due to a tapering in interest rates between the time of filing of his supplemental testimony and the hearing, his recommended rate of return on equity would have been 0.2% lower if recalculated. Tr. vol. 8, 324. The Order concludes that substantial evidence supports the reasonableness of a rate of return on equity ranging from 9.75% to 10.0%, without a downward adjustment due to the MYRP, and ultimately approves 9.8%. I would have approved an ROE of 10.0% for the following reasons.

First, I question whether the Commission regards 10.0% as a Rubicon across which the Commission must not go. I note that in a 2013 general rate case proceeding, DEP and the Public Staff entered into a settlement agreement which, among other things, included agreement on the ROE at 10.2%. Moreover, a historical review of Commission decisions in general rate cases reveals that this Commission has awarded ROEs in excess of 10.0% in many cases in the past. I do not point this out to indicate that an ROE of 10.2% then makes appropriate an ROE of 10.2% now, rather I point this out only to illustrate that the Commission, in the not-too-distant past, has crossed that "symbolic" threshold. *See* Order Granting General Rate Increase, *Application of Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1023 (May 30, 2013).

Second, I am concerned that the results of the DCF models are inconsistent with the current capital market environment and bias downward the range of reasonableness presented in the Order. The three models most cited by the expert witnesses in this case – DCF, CAPM, and RPM – involve different approaches to estimating the cost of equity. However, there is a crucial difference between the DCF model and the other two models. While RPM and CAPM involve borrowing costs as a direct input to the model, DCF does not involve borrowing costs as a direct input. Thus, the outcome of the DCF is not directly affected or informed by borrowing costs. Rather, borrowing costs are considered only indirectly in the DCF model. Many of the experts relied on analyst estimates to inform the dividend growth rate, which is a key input to the DCF model, and while some unknown but correlated factor between dividend growth rates and borrowing costs could impact the outcome of the model, there is no input for borrowing costs. Although utility stocks can act somewhat like long-term fixed income securities, causing their prices to fall (and dividend yields to rise) when bond yields rise, that does not necessarily happen in lock-step. Too, the higher betas presently observed indicate that

utility stocks are relatively more correlated to stocks and less so to bonds than they were in the past. The point is that there are structural (i.e., as a result of the model inputs) reasons why the output of the CAPM and RPM will rise due to rising interest rates, when the DCF might not necessarily respond in the same way or to the same extent.

Undisputed in the record of this case is that long-term borrowing costs, both for DEP as well as the U.S. Treasury, have risen significantly and are at multi-year highs. During the pendency of this rate case, DEP's borrowing costs have risen from 3.7% to 4.03%, and since the Commission's decision in the Sub 1219 rate case, 30-year Treasury yields have increased from 2.16% to nearly 3.84% as of May 1, 2023. *See, e.g.,* Tr. vol. 9, 41; tr. vol. 22, 196.

The range of reasonableness identified by the Commission in this case equally weights the DCF, CAPM, and RPM, but of the three, only the DCF model produced results below the range and indicated the cost of equity is lower now than it was in the prior rate case, when the Commission ordered rates to be set using an ROE of 9.6%. Given that the record in this case reflects an increase in borrowing costs and given that the consensus of the DCF models remains below the approved ROE in the last rate case, the results deserve a certain amount of skepticism.

The Commission has at various times in the past placed more or less emphasis on a given model in order to reflect its conclusion as to whether the results of that model accurately reflect the utility's cost of equity. *See, e.g.*, Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, Approving Water and Sewer Investment Plan, and Requiring Customer Notice, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates and Charges for Water and Sewer Utility Service in All Service Areas of North Carolina and Approval of a Three-Year Water and Sewer Investment Plan*, No. W-354, Sub 400, at 44 (Apr. 26, 2023); Order Granting Partial Rate Increase, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina*, No. W-354, Sub 128, at 77-78 (June 10, 1994). Because of the very clear signal sent by the bond market that the cost of capital has risen significantly, an ROE at the top end of the range of reasonableness, implicitly giving the DCF result less weight, is both warranted and necessary at this time.

Third, while the Order gives some acknowledgement to DEP's stressed credit metrics, I am concerned that the decision to approve an ROE of 9.8% will ultimately prolong that stress, leading, potentially, to a downgrade. A downgrade will cost customers. Tr. vol. 22, 186.

DEP witness Newlin explained that credit quality (or creditworthiness) is a term used to describe a company's overall financial health and its willingness and ability to repay all financial obligations in full and on time. Tr. vol. 9, 88. He went on to explain that two major credit rating agencies, Standard & Poor's (S&P) and Moody's Investors Service (Moody's), establish credit ratings for DEP.

Witness Newlin testified that DEP must be in a position to operate and maintain its business without interruption and to refinance maturing debt on time, regardless of financial market conditions. He noted that the financial markets can experience periods of volatility and that DEP must be able to finance its needs throughout such periods. He concluded that strong investment-grade credit ratings provide DEP with greater access to the capital markets on reasonable terms during such periods of volatility. *Id.*

In explaining the qualitative and quantitative factors that rating agencies would consider when assessing DEP's creditworthiness, he testified:

> Quantitative measures are primarily based on operating cash flow and focus on the level at which DEP maintains debt leverage in relation to its generation of cash and its ability to meet its fixed obligations (interest expense in particular) based on internally-generated cash. The percentage of debt to total capital is another example of a quantitative measure. Creditors and credit rating agencies view both qualitative and quantitative factors in the aggregate when assessing the credit quality of a company.

Tr. vol. 9, 90.

He also testified that investors, investment analysts and credit rating agencies, in assessing a utility company's financial strength, consider the allowed rate of return, the cash quality of earnings, the timely recovery of capital investments, the stability of earnings, and the strength of its capital structure. *Id*. at 91. Specifically with respect to ROE, he testified that the allowed return on equity is a key component in the generation of earnings and cash flows and that an adequate return on equity helps ensure equity investors receive fair compensation for their investment while also helping to protect the interests of debt investors. *Id.* at 96. He testified further that a strong capital structure and an adequate return on equity provide balance sheet protection and cash flow generation to support high credit quality. Moreover, he testified that high credit quality creates financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs, while a weak capital structure and an inadequate allowed return on equity produces lower earnings and cash flows, lowers credit quality, and may limit financial flexibility. *Id.*

On this record, I am persuaded that ROE is a critical component of creditworthiness. I am also persuaded that high credit quality serves the public interest by putting the utility in a position to compete for capital on the most reasonable terms available and by increasing the potential that the utility will be able to access the capital markets on reasonable terms during all types of market cycles, including periods of high volatility, which, ultimately, lowers borrowing costs passed through to customers.

The Order discusses DEP's stressed credit metrics in the context of capital structure and notes:

> Specifically regarding DEP, Moody's has taken two very recent actions, both of which highlight the immediate credit metric challenges DEP faces. First, in April 2023 Moody's published a "Ratings Action" report (DEP Redirect Newlin Direct Exhibit 1) affirming DEP's A-level rating but at the same time issuing an explicit warning with regard to the principal credit metric utilized by Moody's, the ratio of Funds From Operations (FFO) to debt (FFO/Debt)[1]. In its April 2023 Ratings Action Moody's indicated that it was raising its FFO/Debt downgrade threshold for DEP from 20% to 21% (*Id.* at 4), meaning that while it had in the past forecast a potential downgrade in DEP's credit rating if the FFO/Debt metric stayed below 20% on a sustained basis, it was now forecasting a potential downgrade if the metric stayed below 21% on a sustained basis. This is a particularly worrisome development because, as Company witness Newlin pointed out during his direct testimony, DEP's FFO/Debt ratio has been below 21% for a number of years. Tr. vol. 9, 17-18. In other words, DEP is already operating below the Moody's raised downgrade threshold and has already been doing so on a sustained basis. *Id.* at 18-19.
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> Between witness Newlin's appearance on direct (May 5) and his appearance on rebuttal (May 16), Moody's issued its May 2023 updated Credit Opinion regarding DEP (DEP Redirect Newlin Rebuttal Exhibit 1), replacing its Credit Opinion issued in March 2022 (introduced into evidence as both Public Staff Cross-Examination Morin Direct and Rebuttal Exhibit No. 15 and DEP Redirect Newlin Direct Exhibit 2). In the updated Credit Opinion, Moody's explicitly referenced as factor that could lead to a downgrade the FFO/Debt ratio "remaining below 21% in 2023." DEP Redirect Newlin Rebuttal Exhibit 1, 2; *see also* Tr. vol. 23, 36-37. Accordingly, Moody's not only alluded to its raised download threshold, but pointedly referenced 2023—this very year.

The Order goes on to note that "the potential for downgrade is not a theoretical issue" and characterizes the Moody's actions as "a series of escalating warnings."

However, I do not agree that an ROE of 9.8%, on this record and at this time, takes those warnings seriously. Even with an equity layer of 53.0%, an ROE of 9.8% does not put the utility in a position to address the challenges it faces.

As was testified to extensively in this proceeding, in November 2022, Moody's placed the entire electric sector on negative outlook as a result of a number of factors including higher fuel costs, higher interest rates, large capital spends, and inflation.

[1] In Moody's parlance FFO/Debt is called "preworking capital cash flow to debt," Tr. vol. 9, 115, or "CFO pre-WC to debt." Both FFO and CFO pre-WC mean the same thing and are a measure of cash flow. *Id.*

Tr. vol. 10, 23. In doing so, Moody's noted that financial metrics for the industry at large are already under pressure with little cushion entering 2023. Subsequent to that action, as mentioned above, Moody's took action with respect to DEP specifically, changing the downgrade threshold from 20% to 21%. *Id.* at 15. The evidence of record demonstrates that DEP is below the downgrade threshold now. Tr. vol. 9, 112.

DEP faces substantial capital needs over the next several years to comply with environmental requirements, to replace and upgrade aging infrastructure, to construct or acquire new generation resources, to upgrade the transmission system, and to satisfy its debt maturities. DEP's capital requirements, including MYRP projects, for the next five years (2022-2026) are projected to be approximately $13.6 billion, which includes $1.3 billion in debt retirements. *Id.* at 98. In the very near term, DEP must retire $300 million of first mortgage bonds, which are due in September 2023. DEP Redirect Newlin Direct Ex. 1, Tr. Ex. vol. 23. DEP witness Newlin testified that DEP's capital requirements, including MYRP projects, are expected to be funded from internal cash generation, the issuance of debt, and equity funding from Duke Energy, as needed. Tr. vol. 9, 98. He explained further that DEP is in a growth cycle, due to the Carbon Plan, and that, while not unusual for utilities in a growth cycle, DEP is a cash flow negative company, which means that its source of funds will not necessarily be limited to debt issuance but must include other sources, such as retained earnings from lowering the dividends paid to the parent or even equity injections from the holding company. *Id.* at 110.

Recognizing some of the challenges ahead for DEP, in a May 2023 credit opinion, Moody's noted that recovery of ongoing coal ash remediation costs and storm costs, along with elevated spending for grid modernization, will maintain pressure on credit metrics. DEP Redirect Newlin Rebuttal Ex. 1, Tr. Ex. vol. 23.

DEP witness Newlin testified that the heightened level of market volatility and uncertainty created by events of recent years have led to an unprecedented number of zero issuance days in the primary debt capital markets. Specifically, he testified that there were 48 zero issuance days in 2022 and already 11 such days to start 2023. Tr. vol. 22, 196. During the hearing, he testified as to a specific recent example, which occurred during the week of the Silicon Valley Bank collapse and sale of Credit Suisse to UBS. He explained that while DEP teed up with two other issuers within the Duke complex to issue that week, the market was very unsettled and they were unable to or decided not to issue into that market. *Id.* at 206. Additionally, evidence in the record, which was not rebutted, shows that borrowing costs increase as credit quality decreases. DEP Redirect Newlin Rebuttal Ex. 2, Tr. Ex. vol. 23. Anticipating the refinancing of low-cost debt the DEP must manage in the coming years – $1.3 billion over the term of the MYRP – potentially impacting DEP's credit quality, such that it might be frozen out of the market or have its borrowing costs significantly increase, is a risk that the Commission should not take. I am concerned that 9.8% takes this risk.

On the record and in light of the very real and complex challenges facing DEP in the coming years – including, to name a few, retirement and/or refinancing of debt in a higher interest rate environment, continued coal ash remediation efforts, construction of

MYRP projects, construction of other transmission and distribution system upgrades necessary to ensure reliability and facilitate the transition, retirement of existing generation, construction of new generation, restoration of system damage caused by extreme weather as a consequence of DEP's being a "storm prone service territory,"[2] fuel price volatility, and labor and materials price volatility – I am not persuaded that an ROE of 9.8%, even with a 53.0% equity layer, particularly given several of the other decisions in this proceeding, will give DEP the cushion it needs to remain consistently above its 21.0% FFO-to-debt downgrade threshold to protect against a downgrade. And, again, I am persuaded that a downgrade will cost customers. As DEP witness Newlin explained in response to cross-examination by the Public Staff, sequential drops in the (Moody's) rating translates to an additional cost to the utility to access capital – each drop can amount to additional incremental borrowing costs of 5-10 basis points but perhaps more given market conditions. Tr. vol 23, 23-24. DEP witness Newlin warns that while allowing DEP to recover less for its cost of equity capital may save customers in the short term, over time as debt matures and must be refinanced, such a measure will impose more cost on customers. *Id.* at 27. Moreover, I note that evidence in the record shows that Georgia Power Company has a credit rating of Baa1, which is two notches below DEP's current credit rating. *Id.* at 24. This lower credit rating results in a higher cost of equity capital of 10.5% for Georgia Power Company and, ultimately, its customers.

DEP witnesses also testified to cost-saving measures, O&M savings, undertaken by DEP since its last rate case. Specifically, DEP witness Abernathy testified:

> We did, you know, implement a series of routine cost-cutting measures to address not only COVID impacts, also mild weather, increased storm costs, things we do in normal course of business when faced with revenue pressures.

Tr. vol. 21, 1332.

While I expect DEP to find every efficiency in the provision of service to its customers and mitigate costs it incurs in providing service to the greatest extent practical, cost-cutting in the face of financial pressure, at a certain point, becomes a concern as it has the potential to impact the reliable operation of the electric system. Given the dynamics of the electric system, including changes in the generating mix, as well as the increasingly extreme summer and winter weather in North Carolina, now is not the time to put DEP in a position to cut to the extent that could impair the reliable operation of the system.

Based on the foregoing, I conclude that the Order's lack of enthusiasm for or lack of consideration of the largely unrebutted testimony of DEP witness Newlin as to credit quality and other evidence of record cited in this dissent is ill-founded. The decision to authorize an ROE of 9.8% has the very real potential to further stress DEP's credit

[2] *See* Moody's Credit Opinion for Duke Energy Progress, LLC, 2 (May 11, 2023); DEP Redirect Newlin Rebuttal Ex. 1, Tr. Ex. vol. 23.

metrics, which will cost customers. Given the real-world challenges that DEP must tackle in the coming years, unlike the majority, I am not willing to take that risk.

Fourth, I note that the Commission recently allowed an ROE of 9.8% for the two largest water and wastewater public utilities in North Carolina. Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, Approving Water and Sewer Investment Plan, and Requiring Customer Notice, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates and Charges for Water and Sewer Utility Service in All Service Areas of North Carolina and Approval of a Three-Year Water and Sewer Investment Plan*, No. W-354, Sub 400 (Apr. 26, 2023); Order Approving Motion on Wastewater Rate Design and Approving Schedules of Rates, Schedules of Connection Fees, and Customer Notices, *Application by Aqua North Carolina, Inc. for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Its Service Areas in North Carolina and for Approval of a Water and Sewer Investment Plan*, No. W-218, Sub 573 (July 31, 2023). DEP witness Morin testified that when viewing authorized returns on water utilities versus the authorized returns on vertically integrated electric utilities over a long time period, there is a difference typically on the order of 20 to 30 basis points lower for the water utilities. Tr. vol. 9, 32. My review of the record reveals that no party contested or otherwise rebutted this evidence. While I take no issue with and support the Commission's decisions in the recent CWSNC and Aqua cases, I note that at least in recent history, the trend for ROEs for the water/wastewater utilities and electric utilities has more or less mirrored that testified to by DEP witness Morin – until this Order. I must give this evidence some weight in forming my view that 9.8% is not an accurate reflection of DEP's cost of equity capital.

II. COVID Deferral

I dissent as to the Order's treatment of the deferred COVID-related costs. The Order: (1) approves DEP's recovery of the deferred COVID-related costs pertaining to customer fees waived, incremental bad debt expense, and employee safety; (2) reduces these allowed costs by certain COVID-related expense savings for employee travel expenses, printing and postage costs, DEP's filed ERCs, and the carrying cost benefit of the delayed payment of the employer portion of social security tax; (3) does not allow DEP to recover the carrying costs accrued during the deferral period or a return on the unamortized balance during the amortization period; and (4) requires that these costs be amortized over a six-year period.

The Order notes that approximately 90% of the deferred costs incurred are waived customer fees and incremental bad debt expense and concludes that these two costs resulted directly from governmental action, including mandates from the Commission. For this reason, the Order concludes that the costs associated with waived customer fees and incremental bad debt expense are appropriate for recovery from customers. With respect to employee safety costs, the Order concludes that these costs are appropriate for recovery from customers because to provide essential electric service, many of DEP's employees were not allowed the option to work from home and instead had to show up,

in person, at work, at power plants and other facilities, or to repair damage following storms. I agree with these conclusions.

The Order reduces the costs to be recovered by certain COVID-related expenses. I agree that the amount of deferred COVID-related costs should be offset by savings identified by DEP that were directly attributable to the pandemic, which include: (1) reduced employee expense related to reduction in or elimination of travel, and (2) reduced printing and postage costs as a result of the disconnect moratoriums ordered by the Commission. I do not agree with the Order that costs to be recovered should be offset by the carrying cost benefit related to the delayed payment of the employer portion of social security tax, as the benefit received by DEP was simply a temporary deferral from the government and was fully paid by December 31, 2022. Tr. vol. 21, 1291.

I would have allowed recovery of costs associated with remote work, employee stipends and call center costs because I am persuaded that these costs were incurred as a result of the pandemic and facilitated DEP's seamless, uninterrupted and undiminished provision of service to customers during the pandemic. I am persuaded that the call center costs should be recovered, primarily as a result of DEP witness Quick's testimony as to the efforts DEP went to during the pandemic to serve those customers in need who called in seeking assistance. *Id.* at 1276-77. I suspect and anticipate that these efforts are the foundation for a new approach, going forward, to reaching and serving customers in need that will have real, direct impacts on those customers' bills.

In addition, I would have allowed DEP to recover its carrying costs on the deferred balance during the deferral period as well as on the unamortized balance during the amortization period. Evidence in the record indicates that DEP had accrued carrying costs of $12 million on the total incremental deferred costs of $93 million as of March 17, 2023. *Id.* at 1280.

Finally, I would have allowed DEP to recover these costs over a three-year amortization period, coincident with its MYRP.

At the onset of the pandemic, DEP took immediate action to mitigate the hardship to customers and to ensure the continued provision of the essential electric service to all of its customers in North Carolina. Those actions included waiving all disconnections for customers who did not pay their electric bills and waiving customer late payment fees, return check charges, reconnection fees, and residential customers' electronic payment fees. As I see it, DEP took extraordinary action to provide customer support though efforts initiated on its own, ordered by the Commission, and/or resulting from State of Emergency executive orders. Customers were served, even when unable to pay, and DEP carried those balances for customers for many months, now years, in some cases. This provision of service enabled its customers to work from home, attend school from home, and otherwise remain in the home minimizing risk to others. As the AGO pointed out,

> The health and safety of communities are affected by the efforts of all residents to stay home and socially distance to slow the spread of the

coronavirus. Accordingly, entire communities benefit from efforts to keep electric service turned on in households that are struggling.

Reply Comments of the Attorney General's Office, *Joint Petition of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, for Approval of Accounting Order to Defer Incremental Expenses as a Result of COVID-19*, Nos. E-2, Sub 1258, E-7, Sub 1241 (Nov. 30, 2020).

I agree strongly with the AGO that DEP's actions during the pandemic benefitted all customers, not just those who were unable to pay. In addition, DEP's provision of service during the pandemic and disconnect moratorium periods, without the ability to disconnect for non-payment and with the obligation to enter into longer-term payment arrangements, goes to the heart of the regulatory compact.

In my view, the regulatory compact can be framed as follows. In exchange for an exclusive service area sanctioned by the State, the utility accepts an obligation to serve all customers within that service area, subject to regulatory oversight. Additionally, in return for agreeing to commit the necessary capital for the provision of service, the utility must be given the opportunity to earn a fair and reasonable return on that capital. *See generally*, Charles F. Phillips, Jr., The Regulation of Public Utilities, 21, 3d ed. (1993).

I conclude that the record in this proceeding demonstrates that DEP met its obligation under the regulatory compact. It served customers throughout the pandemic-related moratorium period, regardless of whether those customers paid. It had to carry the amounts owed by the customers who could not pay throughout the moratorium, during a period of time when, as the record demonstrates, DEP faced revenue pressures. Tr. vol. 21, 1332. And, DEP was directed by this Commission to enroll automatically customers who had been unable to pay into extended repayment plans. The late fee moratorium, which I view as an incentive for the payment of bills and which was in effect by order of this Commission, was not lifted until September 2022 coincident with the lifting of the State of Emergency declaration related to the pandemic.

Thus, the actions of this Commission obligated DEP: (1) to provide service even to those customers that were not able to pay their bills: (2) to cease to use its approved tools that are incentives for bill payment for a prolonged period of time; and (3) to enter into extended payment plans with customers. The record reflects that DEP complied with the orders of this Commission. No party to this proceeding took issue with DEP's provision of service during this period of time or with the prudency of the costs incurred by DEP to this end. While the Order reflects a balancing of equities to arrive at the final decision, I do not agree with the balance struck. Customers who were unable to pay benefitted during the pandemic and during the extended period of time for repayment of any amounts owed to DEP. All customers benefitted as DEP's actions allowed households in need to continue to have service in their homes during a time when remaining at home was essential to the health and well-being of all. Denying DEP an opportunity to recover all of its costs does not recognize the value that DEP provided to all of its customers. In addition, I note that the denial of the carrying costs is roughly equivalent to 10 basis points, perhaps more. Thus, I am

concerned that this decision compounds the majority's decision to authorize an ROE of 9.8% and that it will erode DEP's financial health, to the detriment of all customers.

The public health situation presented by the pandemic was an unforeseen, unimaginable crisis that impacted the lives of all North Carolinians in many, difficult and, often heart-breaking ways. DEP's efforts to continue the provision of service to all customers during this time and to provide assistance to those who were unable to pay were critical to the health and general well-being of North Carolina. Tr. vol. 21, 1273-74. In my view, aptly captured by the Attorney General's Office, DEP provided service that benefitted all North Carolinians. I do not believe it is appropriate to deny DEP an opportunity to recover all of its costs, including its carrying costs. This Commission ordered DEP to take action, which included carrying costs for customers who could not pay. DEP upheld its obligations under the regulatory compact. This Commission should have done the same.

III. Affordability – Next Steps

As explained in the Order, DEP requested approval of a CAP and two new tariffs, the CAP Rider and the CAR Rider. DEP witness Harris testified that the CAP proposal, initially developed in the LIAC docket, is designed to assist low-income customers who are facing affordability challenges. Under the CAP, eligible customers would automatically receive a $42.00 monthly bill credit for a 12-month period. Customers who are eligible for and receive funds from either the Low Income Energy Assistance Program (LIEAP) or the Crisis Intervention Program (CIP) would qualify for assistance under the CAP. DEP would automatically enroll eligible customers into CAP using a list of customers provided by the North Carolina Department of Health and Human Services (DHHS). The Order also explains that in addition to the $42.00 bill credit on their next 12 monthly bills, DEP will refer CAP customers to other income-qualified weatherization and energy efficiency services that can assist customers with reducing energy usage.

Public Staff witness D. Williamson testified that the concept of the CAP emanated in the LIAC stakeholder meetings, during which a diverse group of stakeholders met over the course of a year to discuss affordability challenges being experienced by low-income customers to propose ways to address those challenges. He testified that one particular proposal (Proposal 24) contained within the LIAC Final Report combined proposals submitted by the NCJC and by Duke and that Proposal 24 received broad support among the LIAC stakeholders. He testified that DEP estimated 60,000 eligible customers would participate and developed its costs associated with the program based on that estimate. Public Staff witness D. Williamson testified regarding the Public Staff's concerns with the cross-subsidization issues created by the CAP, tr. vol. 20, 144, as well as the Public Staff's preference that there be a clear legislative directive for the development and deployment of assistance programs like the CAP. *Id.* at 146. Ultimately, the Public Staff recommend approval of the CAP for a three-year pilot term, running concurrently with the MYRP, on the basis of the uncertainty of CAP-related costs resulting from the unknown number of potential recipients and the potential for the CAP to be more impactful to non-participating customers than anticipated. He also testified as to concern that once an

affordability program is initiated, it would be difficult to end the program regardless of the costs, benefits, or impacts on CAP recipients and non-participating customers. He testified that the three-year pilot period would provide the Commission with an opportunity to evaluate the performance of the CAP. *Id.* at 147.

Sierra Club witness Howat endorsed and advocated for the reporting of certain data at a zip code level primarily to inform program design and targeting of effective energy efficiency and other affordable energy programming. Tr. vol. 18, 201-02. He advocates that the CAP bill credit be tiered based on zip code level data. *Id.* at 219.

As the Order points out, DEP took issue with the recommendation related to the disclosure of zip code level data. Specifically, DEP witness Barnes testified that DEP opposed the sharing of non-public customer information data aggregated at a zip-code level, noting that DEP's Code of Conduct, approved by the Commission in its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, *Application of Duke Energy Corporation and Piedmont Natural Gas, Inc., to Engage in a Business Combination Transaction and Address Regulatory Conditions and Code of Conduct*, Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682 (Sept. 16, 2016), prohibits the disclosure of aggregated non-public customer data. Tr. vol. 22, 87.

The Order notes that on May 4, 2023, DEP, DEC, Sierra Club, NCJC, et al., and the Public Staff filed the Affordability Stipulation, pursuant to which DEP agreed to withdraw the Low-Income/Affordability PIM it had initially proposed and instead would ensure that a shareholder contribution of $16 million to benefit income-eligible customers would be made as follows: $10 million in support of health and safety repairs that would allow for energy efficiency and weatherization upgrades to homes; and $6 million for the Share the Light Fund, which offers customers bill payment assistance. In addition, DEP agreed to implement the CAP as a three-year pilot, on the Public Staff's recommendation, and to convene a stakeholder engagement process to consider CAP data, metrics, and future CAP program features. The Order also notes that the Affordability Stipulation provides that parties agree to explore "a tiered customer assistance program based on income levels if that feature can be incorporated into the design of the CAP."

The Order approves the Affordability Stipulation but, problematically in my opinion, directs DEP to take action beyond that required by the Affordability Stipulation. Specifically, in a section entitled Affordability – Next Steps, the Order directs DEP to convene a stakeholder group which includes the stipulating parties to the Affordability Stipulation within 90 days of issuance and to invite members of the LIAC to join that stakeholder group. The Order further directs that the group meet quarterly and file a report within six months on the data and information that is to be reported to the Commission annually during each of the three years of the CAP pilot. The Order also directs the stakeholder group to develop a tiered program and directs DEP to file a report relating to the feasibility and proposed structure of a program the later of (i) 18 months after the entry of the order in this proceeding, or (ii) when there is one year of data from the CAP.

As a general matter, I note that the Affordability Stipulation represents the give and take of the parties and that the terms and conditions of the stipulation reflect the compromise each was willing to make, as well as resolution of issues disputed in this proceeding. Among the disputed issues was the term of the CAP, which the Public Staff advocated should be limited, at least initially, to a three-year term in order to provide the Commission with an opportunity to examine the impacts of the program. Whether the CAP should be tiered was also disputed, as the Sierra Club advocated that DEP's proposal for a flat credit be modified to a tiered credit. In addition, the disclosure of zip code level data was a contested issue in this proceeding, with the Sierra Club's advocating that all data be reported at the zip code level and with DEP's opposing that recommendation. Going farther than the settlement of issues between the parties to the Affordability Stipulation upsets the balance the parties struck in the resolution of disputed issues and deprives the Public Staff, and the Commission, of the years of data the Public Staff anticipated would be necessary to make meaningful examination of the CAP before having to design a tiered program.

In addition, well beyond the scope of work envisioned in the Affordability Stipulation, the Order directs that the annual report shall include certain data points at the zip code level and directs that DEP report, on a semi-annual basis, certain data regarding health and safety repairs that are made with shareholder funds, again at the zip code level.

While the Order requires DEP to seek from the Commission any waivers necessary to comply with the Order, it is not clear, based on what the Order requires, whether the Code of Conduct and policies underlying the specific provisions of the Code of Conduct will receive the examination they deserve in any such waiver proceeding. In addition, the Order provides DEP no additional funding for the additional work it directs. The majority directs the collection and reporting of this data, as well as the additional time and effort in a quarterly stakeholder process, without any evidence of record indicating what such effort will cost.

Section III of DEP's Code of Conduct prohibits the disclosure of any "Customer Information" without customer consent, and the Commission has determined in a previous decision that the Code does not even allow for the release of aggregated data except as allowed by the Commission. Order Approving Limited Waiver of Code of Conduct, *Application of Duke Energy Carolinas, LLC, for a Waiver of Code of Conduct Section III A. 2(b) and (f)*, No. E-7, Sub 997 (Feb. 29, 2012). Customer Information is defined, in Section I of the Code, as "Non-public information or data specific to a Customer or a group of Customers, including, but not limited to, electricity consumption, natural gas consumption, load profile, billing history, or credit history that is or has been obtained or compiled by DEC, DEP, or Piedmont in connection with the supplying of Electric Services or Natural Gas Services to that Customer or group of Customers." The fact that a customer has been late, is on a payment plan, or is on a particular rate tariff, including enrollment in CAP and the bills for those CAP customers, seem to fall within the definition of Customer Information.

On this record, which is underdeveloped, I cannot agree with the requirement that DEP disclose to the stakeholder group and report to the Commission the zip code level data required by the Order. There is no evidence in the record as to why the Code of Conduct prohibits the disclosure of this type of information or the policy served by the prohibition. There is no evidence in the record as to why this specific information is necessary for understanding the efficacy and impacts of the CAP pilot. In addition, before directing this type of action, I must be persuaded that customers whose data are being collected and shared, or the communities in which they live, will not be inadvertently harmed by such action. Specifically, I would want to be certain that there is no opportunity, once disclosed to stakeholders or otherwise made public, for such data to be used against a customer in a way that might increase affordability challenges for that customer. I recognize that the data will be anonymous and it may be that collecting and disclosing zip code level data poses no risk in this regard, but the record is not developed on these issues, in particular risks to the customers that the majority is trying to serve. Because I agree that the Code of Conduct adopted by the Commission deserves more respect than that shown by the Order, I would not have imposed additional obligation on DEP.

Finally, I agree with the Public Staff that addressing affordability for the most vulnerable customers is, and must continue to be, a critical focus of the utility and the Commission. However, given the concerns expressed by the Public Staff, as well as by CIGFUR witness Phillips, regarding cross-subsidization, the reduction of customer usage through energy efficiency – actually reducing the amount of electricity that a customer must use and pay for – better serves customers. While I support the give and the take, as well as the outcome, of the Affordability Stipulation, I would not have gone beyond the stipulation, as the majority does, for this reason. In my view, DEP and its stakeholders' resources and efforts are well-spent identifying and developing programs that maximize the deployment of federal funding available for weatherization and energy efficiency, particularly funding that results from recent federal legislation, to the advantage of those customers in need. I see DEP's Residential Income-Qualified Energy Efficiency and Weatherization Program, Order Approving Program, *Application by Duke Energy Progress, Inc. for Approval of Residential Income-Qualified Energy Efficiency and Weatherization Program*, No. E-2, Sub 1299 (Mar. 1, 2023), as the type of program that better addresses energy burden and intensity. I also see the availability of federal dollars available for weatherization as a significant and real opportunity to expand the reach of this program to customers in need and to provide longer term assistance to these customers. My hope is that DEP's resources and attention remain on this program and on the opportunity for its customers created by the availability of the federal funding.

/s/ Charlotte A. Mitchell
Chair Charlotte A. Mitchell

DOCKET NO. E-2, SUB 1300

Commissioner Daniel G. Clodfelter, concurring in part and dissenting in part:

I am in agreement with the Commission's Order in all respects save one, and as to that lone issue I dissent. With respect to all other matters I concur, but I write separately to elaborate two points, one concerning performance incentive measures and the second relating to recovery of rate case expense associated with DEP's prior general rate case, the 2019 Rate Case. I address first the issue as to which I dissent.

I. Revenue Decoupling and Electric Vehicles

It is all very well that DEP's proposal for estimating revenues derived from residential electric vehicle (EV) charging would potentially support and encourage increased adoption of EVs by residential customers.[1] But first, before that worthy objective can be considered, the proposal must fit within the actual language of N.C.G.S. § 62-133.16(c)(2). It does not do so, based on a plain reading of the statute. The statute requires that EV revenues eligible for exclusion from the residential revenue decoupling mechanism are those derived from DEP's EV-specific riders or tariffs, not revenues that are derived from some method of estimation, however reasonable the process of estimation may be. The arguments on this point – and the defects in DEP's methodology for estimation even if estimation were proper in the first place – are well developed in the AGO Post-Hearing Brief at 9-18, and I adopt them here.[2]

II. Performance Incentive Measures

On the matter of performance incentive mechanisms (PIMs), N.C.G.S. § 62-133.16 is not especially demanding, requiring only that "one or more" PIMs be included in a rate application under that section. Even by that modest standard, I find the PIMs offered up pursuant to the PIMs Stipulation underwhelming.[3] Largely if not entirely based on the proposed reliability PIM, however, I am willing to accept that DEP's Application complies with the minimum requirements of the statute.[4] The reliability PIM establishes a target that

[1] AGO witness Nelson challenged whether this claimed linkage actually holds, but for the present I am willing to accept the claim.

[2] I acknowledge that in the PIMs Stipulation DEP agrees to work with the Public Staff and file within 90 days "EV tariffs and/or programs to estimate and update" revenues from EV charging. I do not consider this "and/or" commitment to be sufficient. After DEP has filed and has received approval for specific tariffs for residential EV charging, the decoupling mechanism can be revisited and modified as appropriate.

[3] I will not discuss the PIMs presented in DEP's original rate application since they are no longer before the Commission, except to say that I found the analysis and critique of those proposals by Public Staff witnesses Thomas and D. Williamson, by AGO witness Nelson, by CIGFUR witness Gorman, and by NCJC, et al. witness Posner to be highly persuasive.

[4] I am content to accept, for this first round of ratemaking under the new paradigm, the revised Time Differentiated and Dynamic Rate Enrollment PIM and the Renewables Integration and Encouragement PIM as they are set forth in the PIMs Stipulation, though I do not place much weight on them. I agree with several of the non-stipulating intervenors that those PIMs are not especially well-designed and that they address matters that likely do not require the "push or pull" of a PIM incentive to move the issue forward. Directives and initiatives

responds to the policy goals set forth in N.C.G.S. § 62-133.16(d)(2)(j) and likely also (d)(2)(i); it is well-defined and objectively measurable; and it is primarily, though not solely, under DEP's control. These are all necessary elements for a PIM pursuant to N.C.G.S. § 62-133.16(c)(3).

Though the requirement that it do so is not expressly spelled out in the enabling statute, the reliability PIM is also well-integrated with the other elements of DEP's MYRP application. It will provide some evidence, albeit indirect, of the success of DEP's proposed MYRP investments in transmission and distribution infrastructure over the period of the MYRP. Since these investments lie at the core of the MYRP, it is especially valuable that at least one of the proposed PIMs is linked to that core. Given the new ratemaking environment created by the multi-year ratemaking structure, with the many attendant and new forms of risk and reward for both DEP and ratepayers, I would have preferred to be grappling with PIMs that more directly spoke to the challenges that new ratemaking environment presents. For example, PIMs that would reward DEP for realizing reductions in operating costs and expenses, in order to balance the upward pressure on rates from year-to-year, or PIMs that would incentivize DEP to deliver the capital projects identified and included in the MYRP investment plan on time or under budget, in order to protect against the risk that revenues would have been earned on projects never completed, or delayed, or cancelled due to cost, could have more closely aligned the risks and rewards of the PIMs themselves with the potential risks and rewards of the MYRP.[5]

I do not fault DEP that this did not happen. With no prior history in designing and structuring PIMs and with little specific direction from the statute or from the Commission's rule about how to do so, DEP understandably defaulted to measures that were readily at hand and could be set up and proposed without great effort. Nor do I fault the Commission for not providing, in Rule R1-17B, more explicit guidance for DEP with respect to such things as the preferred or desired policy goals for PIMs and the methods for structuring PIMs to best achieve those goals. The Commission was given the task of implementing the new ratemaking paradigm established by the PBR Statute on a short timetable that simply did not permit an extended process of analysis, review, and stakeholder involvement on such matters. One thing that has been apparent from conversations with commissioners in other jurisdictions, from academic literature on the topic, from presentations on the topic of performance-based ratemaking at conferences, and from the work of the NERP task forces in North Carolina is that successful implementation of a robust system of performance-based incentives requires considerably more time and more stakeholder involvement than was available in the present circumstance. Put

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stemming from the Carbon Plan, the recently approved revised residential NEM tariff, and the revised non-residential NEM tariff approved in this case are likely to provide more than sufficient incentives for interconnection of new renewable resources, for expanded adoption of net metering, and for migration to time-differentiated rate structures. As several intervenors also note, the financial rewards proposed for these PIMs are modest, far less individually and collectively than the statutory cap, and are therefore unlikely to drive any significantly different behavior by the utility than what would otherwise occur without the PIMs.

[5] The reporting requirements set forth in Rule R1-17B(h)(2) and (3) do permit tracking of performance relative to capital projects included in the MYRP, including such matters as project substitutions, delays, and costs relative to projections, but they lack the incentive element that would have been provided by a PIM.

another way, the development of a sound policy and regulatory basis for PIMs – most especially the process for prioritizing and selecting goals for PIMS that are supportive of and integrate well into the larger framework of regulatory policy initiatives – is just not something that could be done in a hurry. In the present instance DEP, the various intervenors and interested parties, and the Commission have done the best that could be done in the time that has been available.

First time attempts to tackle any new challenge – or to take up an old challenge in a new way – may prove rocky and will most likely produce surprises and disappointments. This first MYRP rate case effort has not proved otherwise. What is most important now is that we build upon this experience and spend the time we collectively have between now and when DEP's next MYRP rate case is expected to be filed working to build out a more robust structure for selecting, developing, evaluating, and implementing PIMs. In particular, I believe it would be valuable for DEP and interested stakeholders to engage in a deeper discussion concerning the priority among the various optional policy goals set forth in N.C.G.S. § 62-133.16(d)(2) in order to ensure that the PIMs incorporated into an MYRP reinforce and build upon the policies embodied in the Carbon Plan and in related regulatory initiatives. To this end, I believe the Commission should revisit the recommendations made by the Public Staff and by a number of other intervenors in the original rulemaking docket that the Commission initiate a more extended and in-depth proceeding to put more "flesh on the bones" of the statute and of existing Rule R1-17B.[6] As we noted in our Order adopting Rule R1-17B, "the Commission may choose to initiate dockets to set policy goals for PBRs if it determined in the future that such dockets would be useful."[7] This is our opportunity to build out a more meaningful platform to enable DEP and its ratepayers to benefit from the potential contained in the performance-based ratemaking elements in the PBR Statute. We need to take that opportunity while we have time to do so and before the next MYRP is upon us.

III. Recovery of Additional Rate Case Expense Associated with 2019 Rate Case

The Commission has allowed recovery through the rates established in this case of certain additional rate case expenses associated with and arising out of DEP's prior

[6] E.g., Initial Comments and Proposed Rule of the Public Staff, Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178 (Nov. 9, 2021); AGO Reply Comments, Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178 (Dec. 17, 2021); Comments and Partial Proposed Rules Submitted on Behalf of North Carolina Justice Center et al., Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178 (Nov. 21, 2021); Reply Comments of CIGFUR I, II and III, Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178 (Dec. 17, 2021). The position taken by these parties is also supported by the PBR Regulatory Guidance document issued by the NERP working group, which noted the process of developing, monitoring, and evaluating PIMs is best considered an "iterative" process. See PBR Regulatory Guidance - Implementation Suggestions for the NCUC from the North Carolina Regulatory Process at 19 (Dec. 22, 2020).

[7] Order Adopting Rule, Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, No. E-100, Sub 178, at 14 (Feb. 10, 2023).

general rate case, (2019 Rate Case).[8] It has done so over the strong objection of the Public Staff, and it has acknowledged the justice of the Public Staff's position. But for one overriding factor, I would be inclined to deny recovery of the additional 2019 Rate Case expense for the reasons well stated by the Public Staff.

At the time of the Second Agreement and Partial Stipulation of Settlement between DEP and the Public Staff on July 31, 2020, DEP already knew that due to the Covid-19 pandemic the hearing of its 2019 Rate Case would be conducted under considerably different circumstances than were customary – that the hearing would be conducted remotely, that portions of the hearing would be consolidated with the hearing of common issues in the then-pending general rate case involving DEC, and that there would likely be delay in hearing those portions of the case that were specific only to DEP. In addition, DEP knew at that time that the Commission's Order in the 2017 Rate Case was on appeal and that there was a risk that order would be reversed in whole or in part and remanded for further proceedings. In its negotiations with the Public Staff, DEP could have taken steps to protect itself from these "known unknowns" affecting rate case expenses, but it did not do so.

The Supreme Court's action to remand to the Commission for further proceedings the order in the 2017 Rate Case came after the close of evidence in the 2019 Rate Case and after the parties had submitted their post-hearing briefs and proposed orders. One possible result of that remand could have been extended re-litigation of issues from the 2017 Rate Case and, even quite possibly, re-opening of the record in the 2019 Rate Case to permit the parties to offer additional evidence or argument concerning the effect of the Supreme Court's ruling on coal ash cost recovery issues in the 2019 Rate Case. In the end, DEP, the Public Staff, the AGO, and others were able to resolve the issues arising from the remand of the 2017 Rate Case in a settlement agreement that was comprehensive in nature and eliminated the risk of prolonged and expense continuing litigation. I consider the result obtained by this resolution to be far less costly for ratepayers in both the short term and in the long run than that alternative. For that reason, and that reason alone, I concur in the Commission's disposition of the issue of supplemental rate case expense associated with the 2019 Rate Case. As does the Commission in its Order, I find the circumstances to be unusual and wish to emphasize that I do not consider this disposition to be precedential for future cases.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

[8] Strictly, a good portion of these additional expenses can also be said to relate to DEP's next previous general rate case, the 2017 Rate Case, since they were incurred as a result of the Supreme Court's partial reversal and remand of the Commission's Order in the 2017 Rate Case.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 20-G-0101 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Corning Natural Gas Corporation for Gas Service.

Case 16-G-0204 - Petition of Corning Natural Gas Corporation to Defer Leak Survey and Repair Costs Over and Above the Level Last Established in Rates.

ORDER ESTABLISHING RATES AND RATE PLAN

Issued and Effective: May 19, 2021

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on May 19, 2021

COMMISSIONERS PRESENT:

John B. Howard, Interim Chair
Diane X. Burman, concurring
James S. Alesi
Tracey A. Edwards

CASE 20-G-0101 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Corning Natural Gas Corporation for Gas Service.

Case 16-G-0204 - Petition of Corning Natural Gas Corporation to Defer Leak Survey and Repair Costs Over and Above the Level Last Established in Rates.

ORDER ESTABLISHING RATES AND RATE PLAN

(Issued and Effective May 19, 2021)

BY THE COMMISSION:

I. INTRODUCTION

In this Order we establish rates and a rate plan for Corning Natural Gas Corporation ("Corning" or "the Company"). In lieu of the one-year revenue increase of $6,256,000 requested by the Company, we determine that a base rate reduction of $766,000 is required. The revenue requirement supporting the $766,000 decrease is detailed in Appendix 2. In addition to the base rate decrease, a $1.3 million tax surcredit is expiring and the Delivery Rate Adjustment ("DRA") surcharge is forecast to be reduced by $30,000. Including the impact of the expiration of the surcredit and change to the DRA, the total net revenue

impact on ratepayers will be an annual increase of $505,000. The overall revenue increase is 1.77% over the twelve-month period ending January 31, 2022 ("Rate Year"). The average annual bill impact on residential customers during the Rate Year will be an increase of approximately 2.43%. We are also improving the Company's low-income program. Due to these improvements qualifying low income customers will see an annual bill decrease of approximately 6.14%.

In this Order we also continue a number of positive and negative incentive mechanisms and direct a number of measures to ensure that the Company continues its leak-prone pipe replacement program at its current level, increases its efforts to reduce its leak backlog, minimizes excavation damage to its facilities, maintains its current targets for fast response times in emergencies, fully complies with pipeline safety regulations, increases its work to repair minor leaks in a flood-prone area, improves its coordination with and training of other emergency responders, and establishes a pilot program for residential methane detectors. We also continue and improve the Company's customer service metrics and programs to minimize complaints, achieve good results on customer satisfaction surveys, and minimize missed appointments, uncollectibles and terminations. We also direct an improvement to the Company's outreach and education plan, approve a proposal by Staff (accepted by the Company) to eliminate fees for credit and debit card payments, and approve a proposal by Staff (also accepted by the Company) to file a plan for electronic Deferred Payment Agreements.

II. PROCEDURAL BACKGROUND

On February 27, 2020, Corning filed with the New York Public Service Commission (the "Commission") revised tariff

leaves with an effective date of April 1, 2020 (the "Rate Filing"). Using as a base period the 12 months ended September 30, 2019 (the "Historic Test Year"), the revised tariff leaves would result in an increase in revenues from the Company's gas operations of $6,255,926 in the Rate Year. The Company proposed a three-year rate plan encompassing the initial Rate Year and the two succeeding rate years (the 12-month periods ending January 31, 2023, and 2024), with rate increases of $845,142 and $680,913, respectively. The Company asserted that three years of stand-alone rate increases would impact customers' total bills by 23.4%, 2.56% and 2.01%, respectively. Corning proposed that these increases be levelized over three years, which it asserts would result in an increase of $3,523,167 in each Rate Year, with a total bill impact of 10.93% in each Rate Year.

In the Rate Filing, Corning indicated its openness to developing a staged increase proposal for the 12 month periods ending January 31, 2025, and January 31, 2026. Under the staged increase approach, the Company would recover the carrying costs on incremental plant additions over the previous year. As an alternative to the staged increase, Corning suggested a construction surcharge mechanism ("CSM") that would permit the Company to establish a surcharge factor to be applied to all delivery customers, except those with contractually determined prices, that would permit the Company to cover the carrying costs on projected infrastructure investments.

The Rate Filing included prepared testimony and exhibits constituting Corning's direct case. In Attachment B to the transmittal letter for the Rate Filing, Corning summarized the major drivers behind the proposed rate increases. Of the $6,255,926 Rate Year increase, the costs of mandated initiatives comprise $4,535,731. Of that total, $3,122,469 was in response to legislation enacted by the State of New York, including in

particular the Climate Leadership and Community Protection Act (the "CLCPA"). Corning's filing asserted that such accelerated depreciation is necessary because the CLCPA will shorten the effective life of the Company's existing and future investment in infrastructure. The $3,122,469 increase in revenue requirement from the proposed accelerated depreciation is the largest single issue in this case, amounting to nearly half of the proposed one-year rate increase.

This proceeding was commenced upon the Commission's receipt of the Rate Filing and two Administrative Law Judges (ALJs) were appointed to preside over this case. Procedural and technical conferences were held remotely on April 14, 2020. On April 24, 2020, the ALJs issued a Ruling on Procedure and Schedule, establishing dates for the filing of Company updates, direct testimony of Department of Public Service trial Staff ("Staff") and intervenor parties, rebuttal testimony, and the commencement of evidentiary hearings.

On April 16, 2020, the Company filed Supplemental Direct Testimony, and an exhibit, providing an update on financial market conditions and the effect of those conditions on risk perceived by equity investors. On May 12, 2020, Corning filed updates and corrections to the Rate Filing, consisting of additional direct testimony and revisions to certain exhibits.

On June 26, 2020, Staff and Multiple Intervenors ("MI") filed direct testimony and exhibits, and an individual intervenor-party, Bob Wyman, filed direct testimony. On July 14, 2020, the New York Geothermal Energy Organization ("NY-GEO") filed comments opposing Staff's rejection of Corning's proposal to shorten depreciation service lives. On July 24, 2020, the Natural Resources Defense Council ("NRDC") and the Sierra Club filed joint comments voicing similar opposition to Staff's position. On July 24, 2020, Corning filed

rebuttal testimony and exhibits and Mr. Wyman filed rebuttal testimony. Corning filed supplemental rebuttal testimony on July 30, 2020.

By letter dated August 4, 2020, Corning provided notice of impending settlement negotiations to the Secretary, the ALJs, and the parties in this case. By separate correspondence dated August 7, 2020, Corning set August 21, 2020, as the date for the commencement of settlement negotiations.

On August 10, 2020, the ALJs held a prehearing procedural conference. On August 12, 2020, the Examiners issued a Ruling on Schedule and Procedure, which, among other things, cancelled the evidentiary hearings previously scheduled to commence on August 17, 2020, and required biweekly reports on the status of the settlement negotiations.

The Commission next scheduled information sessions and public statement hearings, which were subsequently held remotely on September 22, 2020. Corning presented its settlement offer at the August 21, 2020 settlement conference. It was anticipated that a Staff counter-offer would be presented at a subsequent settlement conference. Corning provided the ALJs with biweekly reports from September until early March 2021. To accommodate the potential for a settlement, Corning, by letter dated November 20, 2020, agreed to an extension of the statutory suspension period from January 29, 2021, to June 1, 2021 conditioned upon a "make-whole" provision to keep customers and the Company in the same position as they would have been absent the extension. On January 22, 2021, the Commission granted the extension through May 31, 2021.

The ALJs required Corning to provide notice, by March 17, 2021, whether it would request a further extension of the suspension period to continue pursuing settlement. Corning

decided not to request a further extension of the suspension period and notified the ALJs of its decision on March 18, 2021. The ALJs held a prehearing conference on March 19, 2021, and presided over an evidentiary hearing on March 23, 2021. The resulting record consists of 1,259 pages of stenographic minutes and 55 exhibits. At the conclusion of the evidentiary hearing, the ALJs established a briefing schedule, with initial briefs due on April 16, 2021, and reply briefs due on April 23, 2021.

Initial briefs were filed by Corning, Staff, MI, Public Utility Law Project ("PULP"), Utility Intervention Unit ("UIU") and Mr. Wyman. Reply briefs were filed by Corning, Staff, and Mr. Wyman.

On April 29, 2021, Corning filed a letter purporting to address certain aspects of Staff's Reply brief. In response, DPS Staff, PULP, and UIU filed letters asking that Corning's letter be wholly disregarded because the ALJs had not authorized sur-replies and any consideration of the substantive arguments advanced by Corning in its filing would prejudice the other parties. We agree that Corning's letter failed to comply with the Commission's procedural regulations regarding sur-replies and thus will not consider it in this Order.

On May 5, 2021, Corning filed another letter, asking the Commission to take administrative notice of the Governor's recent announcement regarding the accelerated reopening of the New York State economy. We will disregard the request for administrative notice in the May 5 letter as an additional unauthorized sur-reply. In that letter, Corning also provided additional information regarding the status of the collective bargaining agreement between the Company and its employees, and the Company's position on wage increases.

On May 6, 2021, Corning filed a letter stating that the union membership voted on May 5, 2021, to ratify the terms

of the collective bargaining agreement. We have routinely recognized the completion of collective bargaining agreements prior to our decision in a rate case, and as discussed below we will do so here.

III. PUBLIC NOTICE

A notice pursuant to the State Administrative Procedure Act was published in State Register on October 14, 2020.[1] Four comments were filed on the page maintained for this case in the Document and Matter Management System. Three of those comments were filed by residential customers of Corning, while one comment was filed by a developer that undertakes business in Corning's service area.

All four comments expressed opposition to the proposed rate increase. One commenter described the Company's proposed rate increase as clever but bad for customers because it is too large. Commenters also asserted the Commission should not allow accelerated depreciation because the costs of climate change should not be borne entirely by ratepayers. They argued the rate impacts are too great, especially for customers on fixed incomes. Commenters argued it is an especially bad time for an increase in rates because of the adverse economic impacts of the COVID-19 pandemic. They argued that even in good times residents and businesses have trouble paying increased gas rates and pointed out that half the population of Corning's service territory is below the poverty line. Commenters also noted the fact that Corning laid-off or furloughed 700 workers due to the pandemic and that those families are still struggling. Commenters argued that the Company's requested return on equity of 10.2 percent is too high, especially since customers cannot

[1] SAPA No. 41-20-00011-P.

afford a significant rate increase at this time. Commenters pointed out that, while the Company cannot at present terminate service for non-payment, customer arrearages are up because of the pandemic and the full extent of the pandemic's impacts will only be realized when the Company can again begin terminating service for nonpayment. Commenters also claim that Corning can take other measures to cut its costs without raising rates so much. Finally, the developer-commenter stated that natural gas is quickly becoming an energy source of the past and that any additional investments in gas infrastructure will lead to stranded assets.

On September 4, 2020, the Secretary issued a notice of public statement hearings to be held, virtually, on September 22, 2020. Two public statement hearings were held on September 22, 2020, at 1 p.m. and 6 p.m. Four speakers made statements. The Town of Bath opposed the rate increase, describing the Company's proposals for return on equity and depreciation as aggressive and insensitive. The Town expressed concerns about meter accuracy and non-redundant plant serving the Town. The three remaining speakers supported the Company's proposal to depreciate all of the Company's assets within 30 years, both to avoid stranded investments and to promote the transition to the use of renewable energy. One speaker categorically objected to any new gas infrastructure investments by the Company.

IV. RATEMAKING ISSUES

A. COVID-Related Austerity Adjustments

Corning filed its rate case on February 27, 2020, prior to any understanding of the extent, if any, that the COVID-19 epidemic would result in financial impacts to Company's customers. Corning initially sought a Rate Year revenue requirement increase of more than 23%, or over $6.25 million.

In its May 12, 2020 update, Corning still sought a revenue requirement increase of over $6.22 million.

Corning claims that its proposed Rate Year revenue requirement reflects the Company's costs of implementing the Commission's policies and goals related to the CLCPA and its efforts to reduce greenhouse gasses, particularly with regards to the accelerated depreciation of its plant. Staff challenges the increase sought by Corning, arguing that such significant revenue requirement increases are almost unheard of, even during periods of economic prosperity.[2] Staff further argues that the Company's filings were ill-conceived in light of the tremendous revenue and rate impacts during the COVID-19 pandemic. Staff asserts that the impacts of the COVID-19 pandemic are unprecedented both in our lifetimes and in the history of the Public Service Commission.

In testimony Staff recommended a Rate Year revenue requirement increase of $270,773.[3] In its brief, however, Staff recommended four additional adjustments, totaling $47,218, and recommended a Rate Year revenue requirement of $223,555.[4] In recognition that Corning's rate plan was filed prior to any understanding of the economic ramifications of the COVID-19 pandemic, Staff also noted that the Commission may make additional discretionary reductions to the increase in the revenue requirement, if the Commission decides the economic climate faced by Corning's customers warrants further reductions. Staff identified four policy-based austerity adjustments that could be made: 1) modifying the amortization periods for regulatory assets and liabilities; 2) removing the

[2] Staff Initial Brief at 3.

[3] Staff Initial Brief at 1-2.

[4] Staff Initial Brief at 1-2.

allowance for management wage increases in the Rate Year; 3) removing the allowance for certain proposed new employees; and 4) removing the accelerated amortization of leak prone pipe ("LPP"). Staff noted that, although these adjustments were not specifically addressed during the evidentiary hearing, the Commission may nevertheless address them in this Order given that they are based on underlying Commission policies.

Corning charges that Staff's suggested methods for further austerity adjustments lack any record basis. Corning urges the Commission not to make any such adjustments because they would be antithetical to the Commission's ratemaking process.[5] This would be illegal, Corning also argues, because they are unsupported by any clearly established nexus between the customer impacts of the COVID-19 pandemic and the issues raised in this rate case.[6]

We discuss these austerity adjustments in greater detail below.

1) Amortization of Regulatory Assets and Liabilities

As of the end of the Historic Test Year, Corning is expected to have $2.864 million of regulatory assets, i.e., moneys owed to the Company, and $0.916 million of regulatory

[5] Company Reply Brief at 2.

[6] Company Reply Brief at 4 and note 13.

liabilities, i.e., moneys owed to ratepayers.[7] To further mitigate the revenue requirement increase, Staff notes that the Commission could accelerate the return of regulatory liabilities to customers and/or defer the Company's collection through rates of regulatory assets. In choosing an approach, Staff recommends weighing the benefits of mitigating the increase in revenue requirement against the costs, to customers, of delaying the Company's collection of regulatory assets.[8] Staff notes that amortizing all new deferrals over ten years would reduce the revenue requirement by approximately $269,972.[9] Alternatively, Staff notes, the Commission could choose to not amortize any regulatory assets in the Rate Year but pass regulatory liabilities back to customers over five or three years. These two options would reduce revenue requirement by approximately $631,884 or $728,348, respectively.

2) Removing the Allowance for Management Wage Increases in the Rate Year

In testimony and its initial brief, Staff recommended allowing union and management wage increases at the general rate

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[7] Staff Initial Brief at 6. For each new deferred asset or liability, including deferred Pension and OPEB costs, the Company proposes to amortize the forecast balances as of January 31, 2021 over a three-year period. Tr. 86, Ln. 1-2, Tr. 87, Ln. 5-6; Staff Initial Brief at 22. Staff disagrees and recommends that, for all new deferrals, except rate case expenses, the actual deferral balances as of the end of the Historic Test Year be amortized over five years, to mitigate the potential rate increase. Tr. 766, Ln. 10-13. For rate case expense, Staff argues a three-year amortization period is appropriate because the Company has historically entered into three-year rate plan agreements. Staff Initial Brief at 22-23. Staff's initial brief incorrectly stated that these balances were as of the beginning of the Rate Year, however we have been advised that the correct time period of these amounts is as of the end of the Historic Test Period.

[8] Staff Initial Brief at 7.

[9] Staff Initial Brief at 7.

of inflation, or 1.34%.[10] However, based on current economic conditions due to COVID-19, Staff suggested that the Commission could consider reducing management wage increases to 0% in the Rate Year and thereby reduce the revenue requirement by $5,139.

Corning contests Staff's proposed 1.34% limit on wage increases based on the general rate of inflation. Corning argues that a 3% increase in wages is necessary to retain its employees. Corning also challenges Staff's assertion that the Commission is authorized to freeze management wage increases based on general concerns about the adverse economic impacts of the COVID-19 pandemic.

3) Removing the Allowance for Certain Proposed New Employees

Staff suggests the Commission could deny cost recovery for four new employees and a contractor that Corning has proposed.[11] This approach, Staff argues, would reflect the fact that many businesses have imposed hiring freezes, and/or terminated or furloughed employees due to financial constraints associated with the COVID-19 pandemic. Imposing temporary limits on Corning's ability to hire new staff, Staff reasons, may be appropriate given these circumstances. Disallowing all four employees and the contractor would reduce the revenue requirement by approximately $344,513. Alternatively, Staff suggests, the Commission could limit the adjustment to only reflect new employees not yet hired by Corning.

Corning opposes this adjustment, arguing that its testimony demonstrates that these new employees will pursue significant tax and operating cost savings that are expected to

[10] Tr. 689, Ln. 3-9; Staff Initial Brief at 17-18.

[11] The Company has asked for cost recovery relating to retaining an information technology (IT) contractor or hiring four new employees: one IT employee, two gas specialists and one laborer. Staff Initial Brief at 8.

offset their salaries and the Company is prepared to reduce future rates to reflect savings that might be achieved.[12]

4) Removing the Accelerated Amortization of Leak-Prone Pipe

Corning's proposed depreciation expense included the amortization of the remaining plant balance associated with LPP over a seven-year period. In testimony, Staff agreed with amortizing the remaining LPP plant balance over the time period of expected removal, to limit intergenerational inequity and reduce rate base for assets no longer used and useful. However, Staff suggests that, to reduce rate impacts on customers, amortization of the remaining LPP plant balance could be pushed outside of the Rate Year and addressed in a future rate proceeding. This would decrease revenue requirement by approximately $439,206.

Corning argues this proposed adjustment has no record basis and, if adopted, will cause intergenerational inequity and lead to significantly increased rates in the future. Corning asserts that, for these reasons, this proposed adjustment must be rejected by the Commission.[13]

DISCUSSION

Over the past fifteen months, because of the COVID-19 pandemic, all State residents have been forced to make hard sacrifices and to bear up under extraordinary and unforeseen circumstances. The Commission cannot ignore the pandemic-related economic hardships caused by the COVID-19 pandemic. When setting rates, we must make adjustments that account, in some degree, for the economic fallout from the pandemic. Failing to do so would, in effect, impose additional hardships

[12] Company Reply Brief at 10-11.

[13] Company Reply Brief at 11.

on ratepayers at a time of unusual and unexpected need. The austerity adjustments offered by Staff are warranted due to the current extraordinary circumstances. While Corning argues recent events have suggested that things are getting better, that is not a rational basis for ignoring what actually happened in the recent past. On the other hand, it is reasonable to require the Company to bear part of the economic burden of recent events.

Accordingly, we adopt Staff's suggested austerity adjustments relating to removing the allowance for management wage increases in the Rate Year; removing the allowance for certain proposed new employees; and, removing the accelerated amortization of LPP. To further mitigate the revenue requirement increase, we will also accelerate the return of regulatory liabilities to customers and/or defer the Company's collection through rates of regulatory assets. In deciding which approach to take, we have weighed the benefits of mitigating the revenue requirement increase against the costs, to customers, of delaying the Company's collection of regulatory assets. We find that an appropriate balance between these competing concerns can be struck by amortizing all deferred regulatory assets, including both pension and Other Post-Employment Benefits ("OPEB") amounts, over a ten year period, and amortizing all deferred regulatory liabilities, other than the OPEB deferral, over a three year period.[14] This will reduce the increase in the Company's revenue requirement by approximately $466,905. These measures, along with the other austerity measures described above, will mitigate the increase in the Company's revenue requirement, and thereby protect the

[14] See Appendix X for a full list of regulatory deferrals and amortization periods.

interests of ratepayers in the context of the still-ongoing COVID-19 pandemic.

Most of the adjustments identified in the prior paragraph fall squarely within the discretion of the Commission in that they are based on underlying Commission policies and thus need not be grounded in any evidentiary record colloquy. It is sufficient that these matters have been raised and countered in the overall case record in the parties' briefs. Although Corning's request for management wage increases and to hire employees for newly created positions are not associated with any underlying Commission policies, we find that Corning has not met its burden with respect to these matters. Specifically, we find that the need to employ austerity measures far outweighs the Company's need to increase management salaries and add these new positions. We also note that the rates at issue in this case will have a one-year duration and, should the economy recover in the interim, such austerity measures would likely not need to be employed in future rate cases.

B. Estimated Sales and Revenues

1. Sales Forecast

Staff made a number of adjustments to the Company's sales forecasts. The Company accepted all of Staff's adjustments and there are no remaining areas of disagreement on this topic.[15] The calculations in Appendix 2 reflect these agreements.

2. Local Production Revenues

The Company accepts Staff's adjustments to delivery revenues, local production revenues, and other transportation

[15] Staff Initial Brief at 10; Company Initial Brief at 10; Company Reply Brief at 15.

revenues.[16] The calculations in Appendix 2 reflect this agreement.

3. Other Revenue Issues

Staff and the Company also agree to continue the mechanism established in the 2017 Rate Order in Case 16-G-0369[17] estabishing annual revenue targets and sharing the difference between the actuals and the targets between customers (85%) and shareholders (15%). Staff and the Company agreed to revenue imputation targets of $1,650,029 for contract revenues and $263,201 for local production revenues, with no changes to the sharing mechanism.[18] While we accept this agreed-upon mechanism, certain contract revenues are dependant on firm delivery rates, and therefore, the contract revenue imputation target needs to be updated to reflect the base delivery rates adopted in this Order. As such, the imputed contract revenue target is set at $1,472,455.

Staff and the Company also agree to Staff's adjustments to the Revenue Decoupling Mechanism ("RDM") to use a revenue per class RDM target rather than a revenue per customer RDM target,[19] Merchant Function Charge target revenue of $40,813 for credit and collections and $82,884 for gas supply

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16 Staff Initial Brief at 10-11; Company Initial Brief at 11; Company Reply Brief at 15-16.

17 Case 16-G-0369, Corning – Gas Rates, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plan (issued June 15, 2017).

18 Staff Initial Brief at 12-13; Company Initial Brief at 12; Company Reply Brief at 16.

19 Staff Initial Brief at 14; Company Reply Brief at 14.

procurements[20], and an uncollectible rate of 0.464% rather than 0.565%.[21] We accept these agreements.

C. Operation and Maintenance Expenses

1. Direct Labor

Staff and the Company agree on Staff's adjustments to set overtime expenses at a three-year average and to correct the vacation accrual.[22] Three of Staff's other direct labor adjustments are disputed: (1) disllowance of the costs of one proposed new IT employee; (2) disallowance of the costs of the Company's incentive compensation plan; and (3) a wage increase of 1.34% based on the general inflation rate rather than the Company's proposed 3% increase. As discussed below, we agree with the first two of Staff's adjustments. In addition, as discussed above in the section on Austerity Adjustments, we are making additional adjustments regarding new employees and management wage and salary increases. The discussion immediately below relates to the specific adjustments proposed in Staff's testimony.

a. Additional IT Employee.

Staff proposed to disallow the costs of two proposed new IT employees. The Company agreed to the removal of the costs of one of the two.[23] Staff argued that the Company's justification was inadequate because the work of the disputed employee is already being handled by other Company employees, and because the tax savings alleged by the Company to be provided by the work of the new employees were not reflected in

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20 Staff Initial Brief at 14; Company Reply Brief at 16-17.

21 Id.

22 Staff Initial Brief at 16; Company Initial Brief at 13; Company Reply Brief at 17.

23 Staff Initial Brief at 18-19; Company Initial Brief at 13; Company Reply Brief at 17-19.

the Company's case. The Company argues that the tax savings will primarily be reflected in future years (and therefore future rate cases), but agrees to notify the Commission of any savings achieved during the Rate Year. We agree with Staff's adjustment. Given the Company's claim that the savings achieved by the employee will more than cover the salary costs[24] and the Company's failure to offset any of the salary costs by expected savings in its case, we disallow the costs of the disputed employee position.

b. Incentive Compensation Plan

Staff proposed to disallow recovery of the costs of the Company's management incentive compensation plan. As Staff testified, the Commission requires a company to make one of two showings for the costs of such a plan to be allowed: (1) that the Company's total level of employee compensation inclusive of incentive pay is reasonable relative to peer companies and that the incentive pay does not contain performance targets that adversely affect customer interests or are inconsistent with Commission policies; or (2) that the incentive pay plan provides quantifiable or demonstrable benefits to customers, in a financial sense, or in terms of reliability, environmental impact or customer service.[25] Staff argues that the Company failed to make either of these showings with respect to its incentive compensation plan. Staff notes that the Company did not provide a compensation study, and that the majority of incentives focus on goals that benefit shareholders, especially in light of the provision of the plan that no incentive is paid if the earnings target is not achieved.[26] The Company argues

[24] Company Reply Brief at 17.

[25] Tr. 923-926.

[26] Hearing Exh. 36 (DSG-1, p. 1); Tr. 927-928.

that all of its business and the work of all of its employees are dedicated to achieving safety, reliability and customer service and that disallowing the costs of the incentive program would send the wrong signal to the Company's employees.[27] The Company also argues that the plan's financial performance goals benefit customers by maintaining the financial strength and solvency of the Company.[28]

We are not persuaded by the Company's arguments. They are broad, general and would justify virtually any incentive compensation plan. We find that the Company has not made the specific showings required by Commission policy, and we adopt Staff's adjustment.

c. Wage Increase.

Staff proposed in testimony to limit the allowed wage increases in the Rate Year to the general inflation rate. The Company proposes a 3% increase. The Company's union contract expired on April 5, 2021,[29] thus requiring a forecasted amount for the Rate Year. Staff's position was that the Company's forecast of 3% was not appropriate in light of the uncertainties of the COVID pandemic, and that the inflation rate should be used to forecast Rate Year wage increases.[30] Staff agreed that the Company could update the record during the course of this proceeding in the event of material changes in union negotiations,[31] but there were no such updates as of the date briefs were due.[32] The Company in its Initial Brief reported a tentative agreement with the union "consistent with the level

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27 Company Reply Brief at 19.

28 Company Initial Brief at 13-14.

29 Tr. 83.

30 Tr. 687-688.

31 Tr. 688.

32 Staff Initial Brief at 17.

projected by the Company for the rate year".[33] In its Reply Brief the Company stated that it expected a contract to be finalized "within a few days."[34] In its May 5 and May 6, 2021 letters the Company informed the Commission that a collective bargaining agreement has been reached and ratified by union membership vote. In the May 5 letter, the Company stated that, although the agreement provides for wage increases of 3.5%, 3.5% and 3.0% for years 1-3 of the agreement, the Company would adhere to its 3.0% Rate Year request in this case. The Company also argues that its forecast is reasonable and consistent with past history and that it may lose employees if its wages are non-competitive.[35]

We will allow a 3% wage increase applicable to the Rate Year as requested by the Company. It is standard Commission practice to recognize completed collective bargaining agreements during the pendency of the case and, as noted above, Staff agreed that the Company could update the record during the course of the proceeding.[36]

2. Insurance

Staff and the Company agree on the use of the latest-known Gross Domestic Product ("GDP") Deflator as the general inflation rate applied to property insurance, injury and damages, other insurance, life insurance and plan administrative costs.[37] The parties disagree on the Rate Year forecast of health care costs. The Company proposes a 10% increase, and Staff applies the general inflation rate. The Company testified

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33 Company Initial Brief at 16.

34 Company Reply Brief at 19.

35 Tr. 83, 114-115; Company Initial Brief at 15-16.

36 However, we make an additional adjustment to management wages and salaries in the section above on Austerity Adjustments.

37 Tr. 700, 724-725; Company Reply Brief at 21.

that health care costs increase at a higher rate than average cost increases.[38] Staff testified that the general pool of costs subject to the general inflation rate includes some costs that are higher and some costs that are lower than the the general inflation rate, and that the inclusion of health care cots in the general pool of costs is consistent with long-standing Commission practice.[39] Staff cites the June 26, 2014 Order Establishing Rates in Case 13-W-0235[40] as the most recent statement by the Commission of its policy, followed since 1986, that:

> ". . . in the generic inflation pool, by its nature, some costs are fully expected to increase faster than general inflation rates while others are not. If medical expense falls into the former category … that does not alter the fact that the generic inflation rate is an average of inflationary and deflationary changes in the prices of all the various goods and services in the pool. Thus, a deviation between the increase in a single pooled cost item such as medical expense, relative to the average increase, does not justify removing that item from the pool in an attempt to predict it separately."

The Company has not convinced us that we should change this policy, and we adopt Staff's adjustment.

3. Regulatory Expenses and Amortizations

Staff and the Company agree on the amounts of regulatory and rate case expenses, on the assumption that the rate case expense amount will be amortized over three years based on the actual amount as of the time of the Commission decision.[41] However, as previously discussed, we are delaying

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38 Tr. 65-67; Company Initial Brief at 18-19.

39 Tr. 803, 931-933; Staff Initial Brief at 15-16.

40 Case 13-W-0235, United Water New York Inc. – Rates, Order Establishing Rates (issued June 26, 2014).

41 Staff Initial Brief at 21-22; Company Initial Brief at 20-22; Company Reply Brief at 23-24.

the Company's collection of its regulatory assets as a means of mitigating the revenue requirement increase. Accordingly, rate case expenses will be amortized over ten years, consistent with other deferrals assets.[42]

Regarding regulatory expense deferrals, the Company objects to Staff's calculation of the balances as of the end of the Historic Test Year as opposed to forecasting them for the Rate Year. The Company argues that forecasting is "normal Commission practice"[43] but fails to cite any Commission precedent. Staff's position is that the Historic Test Year balances have been audited but that forecasted balances cannot be audited.[44] We accept Staff's position for the reason stated by Staff.

Staff and the Company also disagree on the time period for amortization of deferrals other than rate case expenses. The Company's position is that a period longer than three years risks overlapping with the next rate plan, that prior rate plans have used a three-year period and that the period should be consistent with the period of amortization of rate case expenses.[45] Staff proposes a five-year period given the potential for large rate increases in this case and the uncertainties facing ratepayers during the COVID epidemic.[46] We reject both the Company's and Staff's amortization periods. As discussed, we are modifying the Company's amortization of its regulatory assets and liabilities as a means of mitigating the

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42 A listing of Corning's deferred debits and credits for the rate year ending January 31, 2022 is contained in Appendix 3.

43 Company Reply Brief at 24.

44 Tr. 765-766; Staff Initial Brief at 22.

45 Tr. 117-118; Company Initial Brief at 22; Company Reply Brief at 24.

46 Staff Initial Brief at 23.

revenue requirement increase. Accordingly, all regulatory assets will be collected from customers over ten years and all regulatory liabilities, with the exception of the OPEB deferral, will be passed back to customers over three years.

Staff and the Company also disagree on recovery of $349,547 of survey and repair costs related to cold weather that were incurred in 2015. This issue was first raised in a deferral petition that the Company filed on April 13, 2016[47] and remains pending. The Company proposes a three-year amortization of the amount in question. Staff's position is that the Company's request fails to meet the second prong of the Commission's three-prong test for eligibility for deferral treatment and that the Company's deferral petition should be rejected. The parties agree that the request meets the first prong (the expenses are incremental to the amount allowed in rates) and third prong (the Company cannot earn above its authorized rate of return). The dispute is over the second prong: that the incremental amount must be material and extraordinary in nature. The parties agree that the amount is material, and the dispute is therefore over whether the expenses were extraordinary.

The Staff Accounting Panel testified that the expenses were not extraordinary in nature. Staff's analysis is based on the overall heating degree days during the winter of 2015, noting that the winter was only 1.7% colder than the previous winter.[48] Staff also noted that no other gas utility undertook a similar survey of its entire system in 2015.[49] The Company's

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47 Case 16-G-0204, Corning – Petition to Defer Leak Survey and Repair Costs Over and Above the Level Established in Rates.

48 Tr. 752; Hearing Exh. 37 (SAP-2); Staff Initial Brief at 25-27.

49 Tr. 752-753.

position is that the January to February period of that winter was extremely harsh and that frost was deeper than had been experienced in a long time.[50]

We accept Staff's position and deny the Company's deferral petition. Every winter has periods of time that are significantly colder than average. The appropriate period of time for determining whether cold weather is extraordinary is the entire winter, not the period of a particular cold temperature event. As a whole, the winter of 2015 was not materially colder than the previous winter, and it is a common occurrence for heating degree days in January and February to be significantly colder than average in any winter.[51] We also find it noteworthy that other gas utilities did not undertake a similar systemwide survey and repair program during the winter in question.

4. Pensions and Other Post-Employment Benefits

The Company agreed to Staff's adjustments to pensions and OPEBs except for the appropriate period of amortization of new deferrals. As with regulatory expenses, Staff proposes a five-year period and the Company proposes a three-year period. For the reasons discussed above for regulatory expenses,[52] we reject both the Company's and Staff's recommended amortization periods. The pension and OPEB deferrals will be amortized over ten years.

5. Other Expense Items

Staff and the Company agree on many of the remaining expense items, including the costs of pension and OPEB

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50 Tr. 118-119; Company Initial Brief at 23-24.

51 See data for 2013, 2014 and 2015 in Hearing Exh. 37 (SAP-2, page 321).

52 Staff Initial Brief at 22-23; Company Initial Brief at 25; Company Reply Brief at 27.

management, uncollectibles,[53] the low income program, building services, transportation, outside services, inventory and Other O&M.[54] We accept these agreements.

We also note the parties' agreement to eliminate credit and debit card payment fees charged to customers, with an allowance in rates for the relevant costs. The Commission welcomes this agreement and notes that it will save customers approximately $8,000 per year.[55]

6. Productivity

Staff proposes a 1% productivity improvement imputation in the Rate Year forecast of direct labor expense, employee fringe benefits expense and payroll taxes, asserting that this adjustment reflects a long-standing Commission policy to capture unidentified and/or unquantifiable productivity gains, efficiencies and cost savings that could be realized in a Rate Year.[56] The Company opposes such an adjustment, stating that it has already increased productivity by reducing costs, and that the application of the general inflation rate to health care expenses is effectively a productivity adjustment.[57]

We have explained above why the use of the general inflation rate is appropriate for health care expenses as part of a large pool of expenses that are subject to cost increases.

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53 Staff and the Company agree that the Company may file a petition to defer the difference between actual and rate year forecast uncollectibles. Company Initial Brief at 27. Staff clarifies that such a petition must meet the Commission's standard three-prong test for eligibility. Staff Reply Brief at 7. We concur with Staff's clarification.

54 Company Reply Brief at 28-33 reflects these agreements.

55 Company Initial Brief at 29-30; Staff Initial Brief at 103-104; Company Reply Brief at 29.

56 Tr. 824, 827-828; Staff Initial Brief at 21-22.

57 Tr. 63-67; Company Initial Brief at 35-37.

We are not persuaded that the Company's forecasted Rate Year savings capture the level of productivity improvements that the Company can and should achieve. We are also not persuaded that we should abandon our normal practice of imputing a productivity adjustment, and we therefore adopt Staff's proposed productivity adjustment.

7. Taxes

For the most part, the parties are in agreement on tax issues, including property taxes, payroll taxes, revenue taxes, and state and federal income taxes.[58] Staff and the Company also agree to remove from this case and to address in a future rate case the appropriate deferred federal income tax refund balance associated with the federal income tax savings due to customers for the Tax Cuts and Jobs Act of 2017 corporate federal income tax rate reduction.[59] We accept these agreements. An in depth analysis is required to reconcile and determine the tax savings amount that should have accrued to customers as compared to the amount that has been provided to customers by the tax savings sur-credit implemented October 1, 2018. The amount that is determined to be an over or under passback of savings, will be accounted for in the deferred federal income tax refund account. The only area of disagreement related to taxes is Staff's proposed amortizaton of accumulated deferred income taxes over an average depreciable life of 42 years for long-lived assets as opposed to the Company's proposed 30-year amortization for such assets in accordance with its proposal to depreciate all long-lived assets over a 30 year period.[60] Because we are rejecting the Company's 30-year depreciation proposal, we accept Staff's

[58] Company Reply Brief at 42-47; Tr. 123-124.

[59] Staff Initial Brief at 33; Company Reply Brief at 43.

[60] Company Reply Brief at 46-47.

proposal for amortization of accumulated deferred income taxes.

8. Depreciation Expense

By far the largest issue in this case, amounting to nearly half of the requested rate increase,[61] is the Company's proposal to depreciate its long-lived assets by 2050, a 30-year period, as opposed to the depreciation lives that would result from the Company's depreciation study. The Company argues that, because the CLCPA mandates the reduction of statewide greenhouse gas emissions by 85% of 1990 levels by 2050, the statute "effectively shortens the effective life of the Company's existing and future investments in infrastructure."[62] The Company further argues that the CLCPA will reduce customer demand and increase the cost of capital. The Company asserts that the proposed shortened lives "will allow the Company to continue its systematic replacement program with more internally generated funds."[63] The Company also asserts that delay in adjusting its depreciation rates in this case "effectively kicks the can down the road" and would only lead to higher rates in the future.[64]

Intervenor Bob Wyman supports the Company's proposed useful lives for the same reasons stated by the Company.[65] Mr. Wyman agrees that the Company's proposal involves some degree of speculation, but argues that all ratemaking necessarily involes forecasting and some degree of speculation. In this case, Wyman argues, the Company's proposal is reasonable and well-grounded.[66]

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61 Tr. 53.

62 Tr. 52-53.

63 Id; Company Initial Brief at 38-39,

64 Tr. 123.

65 Bob Wyman Initial Brief at 3-6.

66 Bob Wyman Reply Brief at 5-11.

Staff responds that any change in depreciable lives at this time is premature, because it is unknown how the CLCPA will be implemented.[67] Staff also raises concerns about the bill impact of the change, particularly in light of the COVID epidemic.[68] UIU also opposes the shortening of useful lives proposed by the Company. UIU argues that the CLCPA does not explicity state that all gas assets will be retired by 2050, nor has it been determined what role, if any, pipeline infrastructure will play in reaching the CLCPA's goals.[69] UIU also notes that when the Rochester Gas & Electric ("RG&E") steam system in Rochester was retired as no longer profitable, shareholders took on a significant portion of the costs of retirement and assets were transferred to a newly-formed municipal corporation to create a district loop.[70]

We reject the Company's proposal for shortened asset lives and adopt Staff's adjustment.[71] Logically, the shortening of depreciable lives to a 2050 end-point amounts to a forecast that the Company will cease utility operations by 2050 and that none of its assets at that time will have any value. Because the Company has not met its burden of proof that such a result is probable, we find the Company's position to be speculative. It simply does not follow that a target of 85% statewide greenhouse gas reductions by 2050 means that the Company will close up shop by 2050 and that none of its assets will remain in

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67 Tr. 419-420; Staff Initial Brief at 27-29.

68 Staff Initial Brief at 5-6.

69 UIU Initial Brief at 6.

70 UIU Initial Brief at 7; see Case 28612, Op. No. 84-19, Rochester Gas & Electric Corporation – Steam Rates, Opinion and Order concerning Steam Service and Determining Revenue Requirements (issued July 11, 1984).

71 A schedule showing the Rate Year Depreciation Expense is attached as Appendix 4.

service. It is impossible to make a precise forecast at this time of what the Company's business will look like in 2050, but it is clear that the assumption that the Company will be out of business at that time is at the extreme end of many possibilities. These possibilities include business as usual if the State's climate goals can be met through other means, the total or partial use by the Company of renewable natural gas supplies, and the total or partial conversion of the Company's system to renewable hydrogen gas. All of these alternatives are consistent with a financially healthy gas utility using its existing assets long after 2050. UIU is also correct that in an arguably similar situation when RG&E retired its steam system in Rochester, some of the utility assets still had a useful function, and RG&E's shareholders bore much of the cost of early retirement.

Further, several of the Company's rationales – that the CLCPA will lead in the future to lower revenues and a higher cost of capital and that the adjustment will provide more internally generated funds for the Company's capital program – have little to do with the depreciation expense allowance in this case. If revenues decline and the cost of capital increases in the future, those matters will no doubt be raised by the Company in future rate cases, and the Commission will address them at that time. The fact that the shortened lives would give the Company more internally generated funds for its line repleacement program is not a justification for the depreciation proposal. Such an argument could be made for any ratemaking adjustment that gives the Company more cash at the expense of its customers. The argument does not establish that the proposal is appropriate.

It also appears that the Company itself may not believe in its forecast. If the Company truly believes that its

assets will be valueless in 2050, the financial statements that the Company's parent holding company provides on a quarterly and annual basis to the investment community and to the Securities and Exchange Commission should fully reflect these dire circumstances. However, as admitted by the Company's Chief Financial Officer, although the Company's operations are fully reflected in the parent company's financials, the shortened depreciable lives proposed in this case are not reflected in its recent SEC 10-Q and 10-K financial statement filings.[72] It appears to the Commission that the Company is claiming materially worsened financial circumstances to justify a large rate increase, while at the same time it presents financial statements to the investment community on a business-as-usual basis that is at odds with the greatly reduced asset lives claimed in this case.[73]

For these reasons we reject the Company's proposal to depreciate all of its assets by 2050. We are not just "kicking the can down the road." We find that the Company has not demonstrated that its proposed useful lives are anything more than speculation. The dire circumstances raised by the Company are far from the only potential outcomes from the CLCPA. If in the future we were to take the drastic step of directing a regulated gas utility to cease operations, the mechanism to do so would not be what the Company proposes in this case – a large transfer of cash from ratepayers to shareholders. We note also that the Company proposes no plan for its customers to transition away from gas by 2050 and proposes no limitations on

[72] Tr. 166-167.

[73] We note that shortening the asset lives and increasing depreciation expense in the relevant 10-K and 10-Q financial statements would have negatively impacted the reported net income of the Company's parent.

its use of the proposed incremental ratepayer funding. The implementation of the CLCPA by the Commission will be difficult, complicated and potentially expensive, but however it is implemented the plan will not look like what the Company has proposed here.

9. Inflation

The parties agree on the use of the GDP deflator at the time of the Commission decision as the general inflation rate.[74] We accept this agreement.

D. Rate Base

1. Plant in Service and Capital Spending

Staff and the Company disagree on three plant in service and capital spending issues: (1) an increase by Staff in the capital budget to maintain the replacement of bare steel mains at 10 miles per year, rather than the 8.6 mile figure proposed by the Company; (2) Staff's deletion of two projects that were funded in the Company's preceding rate case but not accomplished; and (3) Staff's proposal to continue the downward-only reconciliation mechanism for net plant investment targets in the Rate Year.

We accept Staff's adjustment to the bare steel main replacement program. The Company proposes to decrease the replacement program from 10 miles to 8.6 miles per year "as a COVID mitigation measure."[75] While we appreciate the concern of the Company in this respect, the public safety concerns related to bare steel pipe outweigh the relatively minor decrease in

[74] Company Initial Brief at 17; Staff Initial Brief at 21; Company Reply Brief at 21, 31.

[75] Company Reply Brief at 39.

capital spending that the Company proposes.[76] We therefore direct the Company to maintain its current program of 10 years of pipe replacement per year, and we make allowance for that capital spending in the revenue requirement calculation in this case.

We also accept Staff's proposed disallowance of capital spending for two projects, totalling $230,000, because the Company's last rate case already included funding for these projects.[77] The Company responds that although it did not perform these projects, it expended the allowed capital budget funds on other projects, and that the Commission's capital budget allowance allows for flexible allocations of funding among projects as long as the total allowed budget is spent.[78] Although we agree with the Company that funding these projects a second time would not amount to double recovery of the allowed capital spending in the last rate case, the Company clearly has placed low priority on these projects. We are not convinced that the Company would complete them if we included their costs a second time in this rate case. In other words, the Company has not met its burden to establish that it would actually complete these projects if given a second bite at the apple, and we are concerned that the Company would again use the allowed funds for other projects of its choosing that it did not reflect in this case. A schedule listing our allowances for Corning's Capital Expense Budget is contained in Appendix 5.

We also accept Staff's proposed continuance from the Company's last rate case of the downward-only reconciliation

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[76] The parties agree on the size of the Company's replacement program for unprotected service lines. Staff Brief at 34.

[77] Tr. 411-414; Staff Initial Brief at 35-36.

[78] Company Reply Brief at 40.

mechanism of net plant targets for the Rate Year.[79] This mechanism protects ratepayers against paying for capital expenditures in an amount greater than the Company incurs. The Company argues that although this mechanism has been used in the Company's last three rate cases, it is unnecessary in a single-year rate case because ratepayers are fully protected by the penalties applicable if the Company misses its leak-prone pipe replacement targets.[80] We agree with Staff and will continue the downward-only reconciliation mechanism. The pipe replacement program penalties cover only a portion of the Company's net plant investments, and we see no reason to remove the protection that the ratepayers have had for the last three rate cases against underspending by the Company. Appendix 6 shows the net plant true-up targets, as well as an example for how the true-up calculation is performed.

2. Reporting Requirements

Staff recommends that the Commission require capital expense and variance reporting. These reports should include: (1) a final variance summary of capital expenditures for all capital projects and programs including all on-going and active construction projects and programs; (2) a narrative explaining any cost or timeline differences from estimated costs in the project's white paper; (3) a narrative on project design, permitting and/or construction status, including a detailed construction schedule for each project, for any ongoing projects; and (4) a description of any new projects or programs with, at minimum, information that is provided in a white paper.[81] Staff asserts that it is important for Staff and the

[79] Tr. 422-423; Staff Initial Brief at 37.

[80] Company Reply Brief at 41.

[81] Tr. 423-424; Staff Initial Brief at 38.

Commission to monitor the Company's capital work, and that the reports should be filed with the Commission Secretary within 45 days after the end of each calendar year.[82]

The Company objects to the proposed reporting on the ground that no allowance is made for the costs of staff to prepare the reports. The Company also objects to a filing date 45 days after each calendar year because the applicable data will not be available until approximately 30 days after the end of the year, leaving only 15 days to compile and file the reports. The Company suggests a minimum of 90 days to file the reports.[83]

We adopt Staff's position on the need for the reports. We are not convinced that the additional reporting costs would be so material that they require an adjustment to the revenue requirement in this case. However, the Company makes a reasonable argument about the due date of the reports. To minimize the incremental costs and difficulty of reporting we accept the Company's proposal that the reports shall be due 90 days after the end of the calendar year.

E. Cost of Money

1. Capital Structure

Staff and the Company dispute certain elements that make up the Company's overall after-tax rate of return. After accounting for these differences, Staff recommends that the Commission provide Corning with a return of 6.07% compared to Corning's request of 7.28%. The difference is attributed to disputes over the cost of equity, the common equity ratio, and the cost of long-term debt. In summary, Staff urges the

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82 Id.

83 Company Reply Brief at 44-45.

Commission to reduce Corning's requested cost of equity from 10.20% to 8.45%, common equity ratio from 50.77% to 48.00%, and cost of long-term debt from 4.45% to 3.91%.[84]

Underlying the dispute are the parties' positions on whether using a stand-alone capital structure is appropriate in this matter. Corning proposes the use of such a structure for setting its rates, while Staff, despite providing an analysis of and corrections to the Company's stand-alone capital structure, proposes the use of a hypothetical capital structure to set rates. Staff's recommendation is based on the assertion that it is not clear if the Company and its parent are employing rational financing policies because of the use of preferred equity in the parent company's capital structure. In this respect, Staff notes that it is difficult to determine the extent to which the parent company is effectively leveraged relative to Corning. Staff posits that it would not be appropriate to authorize rates predicated on either Corning's stand-alone capital structure or the consolidated capital structure of the parent because of this difficulty.[85]

Corning counters that a stand-alone structure is appropriate because the Commission has already determined that its ring-fencing measures are appropriate in its 2013 order approving of a Joint Proposal that established the use of a

[84] Staff Initial Brief 39-40. Staff notes that in terms of revenue requirement, a 1% change in the common equity ratio is worth approximately $51,693 and a 10 basis-points change in return on equity (ROE) is worth approximately $44,612.

[85] Staff Initial Brief 41-43.

holding company between Corning and its parent.[86] Corning also notes that Staff's approach ignores the fact that Corning's relatively small size negatively impacts its ability to access capital markets on reasonable terms.

Staff counters that, although the Commission has sometimes allowed the use of a stand-alone capital structure in setting rates where sufficient ring-fencing exists, Corning's Affiliate Standards do not rise to that level. Staff notes that, while Corning's measures were determined to be adequate for establishing the Holding Company, the Commission has not determined that they are sufficient for rate-setting and observes that there are deficiencies from what Staff determined would be suitable in its testimony in Case 16-G-0257.[87] By way of example, Staff observes that Corning has neither implemented a "golden share" provision to prevent the bankruptcy of the parent company or affiliates from affecting the Company, nor issued a non-consolidation letter to demonstrate the implementation of ring-fencing and the creation of the separate legal and credit entity for the utility subsidiary. Staff states that, in the absence of sufficiently strong ring-fencing provisions, the Commission typically compares the stand-alone capital structure of the utility to the consolidated capital structure of the utility's parent in order to ascertain whether they reflect rational financing policies. Staff concludes that because of its concern the Commission should instead use its

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[86] Corning Reply Brief 57-58 (citing Case 12-G-0141, Petition of Corning Natural Gas Corporation for Authority to Form a Holding Company and for Approval of Certain Related Transactions, Order Adopting Terms of a Joint Proposal and Approving Formation of a Holding Company, with Modifications and Conditions (issued May 17, 2013)).

[87] Staff Initial Brief 44. Case 16-G-0257, National Fuel Gas – Rates.

proposed hypothetical capital structure.[88]

We agree with Staff. In particular, Corning's reliance on recent Commission-authorized weighted equity cost rates in New York is misplaced. Those rates were set in the context of multi-year plans. Given that Corning is making no commitment to delay any new rate filing, there is no additional risk to its investors. As for the other issues raised by Corning to support its request that we set rates using the Company's proposed equity ratio of 50.77%, we have reviewed the record and do not find it convincing. In particular, the Company's concerns about its cash flow do not convince this Commission that adjustments in favor of higher utility rates are warranted, particularly where the higher equity ratio would be borne by the utility's customer base through higher rates. While the record is devoid of evidence that Corning's requested 50.77% equity ratio is actually achievable, we also do not see it as a viable figure on which to set the Company's rates. As Staff notes, at best, Corning could be expected to maintain a stand-alone equity ratio of only 48.05% during the Rate Year.[89] To set rates based on an equity ratio higher than the actual rate borne by the Company would unreasonably shift additional costs on customers. Thus, we find that it is appropriate in this instance to employ a hypothetical capital structure and set the Company's rates using a common equity ratio of 48.00% as recommended by Staff.

2. Cost Rates

As for cost rates, Staff and the Company agree on the rates we should use for customer deposits and short-term debt.[90]

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88 Staff Initial Brief 44-45.

89 Staff Initial Brief 47.

90 Corning Initial Brief 68.

The Commission annually sets the customer deposits rate which is currently at 0.05% and is appropriate here. For the cost of short-term debt, Corning forecast a rate of 3.78% and it was not disputed by Staff. We adopt this rate.

3. Long-Term Debt

Corning's requested long-term debt cost of 4.45% is based on the actual or estimated cost of each debt issuance reflecting the effective interest to Corning.[91] There is no real dispute as to the embedded costs used to calculate the Company's long-term debt cost. Instead, Staff takes issue with Corning's projections regarding anticipated new debt issuances that Staff disputes and makes an ultimate recommendation for the Commission to employ a long-term debt cost of 3.91%. Staff attributes the difference to a largely resolved correction related to three outstanding loans, as well as to disputes regarding the amounts and timing of the Company's future borrowing and the cost rate estimates for those anticipated new issuances.[92]

The two parties contest the significance of representations from an M&T Bank communication to Corning indicating that the applicable interest rate for new debt securities would be fixed at 4.75%. The Company claims that this figure is reliable and offers in brief another letter from M&T Bank received post-hearing that ostensibly indicates that, at present, Corning would be charged a rate of 4.57%, which the Company says favorably compares to its requested 4.45%.[93] Staff observes that the M&T Bank letter related to the 4.75% interest rate does not communicate any reliable estimate of the interest rate the bank would require on a loan to Corning during the Rate

[91] Corning Initial Brief 68.

[92] Staff Initial Brief 48.

[93] Corning Initial Brief 68.

Year.[94]

Staff proposes that the Commission look instead to other evidence in the case that demonstrates how M&T Bank determines interest rates when it lends to Corning and apply that formula. Staff notes that M&T Bank calculates the interest rate of 10-year loans at 1.80 percentage points above the yield on the 10-year Treasury and it fixes the interest rate on three-year debt at 3.00 percentage points above the three-year Treasury plus the ask side of the three-year London Interbank Offered Rate ("LIBOR") swap spread. At the time of Staff's testimony, the 10-year Treasury was trading at 0.66% and there was no change forecasted, indicating that Corning's 10-year debt issuances during the Rate Year would be issued at a cost of 2.46%. Also, the three-year Treasury was trading at 0.20% with the three-year LIBOR swap spread equal to 0.06%. With the addition of a spread of 3.00%, the resulting estimate for a cost of 3.26% for Corning's three-year debt issuances during the Rate Year.[95]

We agree with Staff that its formula serves as a reasonable proxy for a litigated result. We adopt that approach noting that we are updating the forecasts for the formula's components to reflect the actual Treasury and LIBOR rates as of the issuance of this decision. Given that we are adopting Staff's formula approach as reasonable, we do not need to rely on Staff's alternative grounds which were based on its observation that Corning has failed to comply with the Commission's Order Authorizing the Issuance of Securities in Case 17-G-0346. However, we do agree with Staff that the Company's failures to promptly disclose the terms of the long-

94 Staff Initial Brief 49.

95 Staff Initial Brief 49-50.

term debts that it issued and to demonstrate the reasonableness of those terms is unacceptable. We expect that the Company will comply going forward and so not require a prudence review.

4. Return on Equity

The largest point of contention surrounds the dispute on the authorized ROE. Corning's requested 10.20% is contrasted with Staff's recommended 8.45%, a difference of approximately $8 million in revenue requirement.[96] Disputed issues involve the composition of appropriate proxy groups, appropriate growth rates for the discounted cash flow ("DCF") analyses, key inputs employed in the capital asset pricing model ("CAPM") analyses, the relative weighting of the CAPM and DCF results, and appropriateness of imputing a size premium. Before we discuss the specific disputes, we note that the Commission's concern is in arriving at a just and reasonable result that balances the needs of the Company to access investment capital with those of the customer that must pay the rates we set.

a. Proxy Groups

A proxy group analysis is used as a guide to reduce the potential for bias and inaccuracy in equity analyst estimates. Selected members of a proxy group should be reasonably comparable to the utility seeking new rates as determined by a set of selection criteria. The elements of such criteria can significantly influence the constituents of a proxy group affecting the final ROE recommendations. Thus, it is important to analyze what criteria has been applied to determine whether those constituent members represent similarly situated utilities.

The Company proposed the use of two proxy groups: a group consisting of a combination of gas and electric utilities;

[96] See Staff Initial Brief 39-40.

and a group consisting of gas only utilities all the members of which were included in the combined group. Staff analyzed only a single group consisting of 33 electric utilities and five natural gas utilities. The two parties agreed on certain criteria for proxy utilities such as each utility maintaining investment-grade credit ratings, not being a party to mergers or acquisitions, and having paid regular dividends. While both parties also evaluated prospective companies to determine how much is earned from regulated operations, Staff measured the amount relative to the companies' revenues while Corning measured their earnings relative to net operating income. Lastly, Corning also included a criterion by which a member could not own generation exceeding 60% of its megawatt-hour ("MWh") sales.[97]

Staff challenged both these differences, noting that the MWh criterion was unreasonably restrictive, and that net operating income created a proxy group that was ultimately much riskier in profile than Corning. On this second point, Staff asserted that inclusion of a riskier, non-utility subsidiary would make it more likely that a subsidiary with poor operating income would be included in the Company's proxy group.[98] Corning defended its exclusion of companies owning significant generation resources as not reflecting a similar risk profile to the Company.[99] Similarly, although Staff contested Corning's use of a gas-only proxy group as being too small, the Company countered that Staff's proxy group consisting of 85% electric utilities does not appropriately reflect the risks associated

[97] Staff Initial Brief 51-53.

[98] Staff Initial Brief 54.

[99] Corning Reply Brief 48-49.

with Corning's gas-only distribution operations.[100] Having reviewed the points raised by both parties, we opt to rely on Staff's proxy group as reasonable.

b. Discounted Cash Flow

As Staff notes, the primary challenge in applying the DCF is determining the rate of growth in future dividends that investors expect. Although Staff contested As Staff contends, the Company's DCF models contain inputs that are problematic and some of which the Commission has rejected in past rate matters.

Staff reasonably demonstrates that Corning's use of earnings growth forecasts rather than dividend growth forecasts for the short-term growth rates is not supported by the record and is of questionable validity at best.[101] The Commission has never endorsed a DCF formula that substitutes earnings growth for dividend growth and we do not see anything in the Company's submittals that would make us inclined to endorse it now. We agree with Staff that the assumption is problematic in that it does not serve to measures the present value of future dividends as intended by the DCF.

Additionally, we agree that Corning's long-term growth rate GDP growth rate derived from forecasted inflation rates and historic real economic growth rates is excessive. Staff demonstrates that the use of historic growth rates creates issues where, as here, there is no demonstration that circumstances for the historic period are adequately similar to current economic conditions and likely to provide an accurate forecast for future growth. In particular, we find compelling Staff's illustration that the Company's historically derived long-term growth rate of 5.52% exceeds the forward-looking GDP

[100] Corning Initial Brief 62.

[101] See Staff Initial Brief 57-58.

estimate of 4.00%, published by Blue Chip Economic Indicators, by 152 basis points, while Staff's long-term growth rate of 4.70% exceeds this forward-looking GDP growth forecast by 70 basis points.[102] From this observation, it is clear that the Company's projection is very likely an outlier and of questionable reliability. Lastly, the Commission has already rejected the arguments raised by Corning regarding the timing of future dividend payments and the effect of the time value of money in Case 08-E-0539.[103] On the record before us, we see no reason to revisit that determination as nothing new has been raised in this case. The Commission's observation there that any additional allowance in the Company's ROE based on adjustments for the timing of dividends would be duplicative for those who actually reinvest dividends and unnecessarily generous to those who do not still applies. Thus, consistent with the Commission's 2008 Con Edison Rate Order, we decline to apply an upward adjustment to Staff's DCF results on which our ROE decision here is based.

c. Capital Asset Pricing Model

Both Corning and Staff calculated CAPM results for their respective proxy groups using a traditional and a zero-beta methodology. The parties differ, however, on the inputs used. Specifically, Staff takes issue with three facets of the Company's analysis arguing that Corning used an excessive market-return estimate of 14.27%, used a flawed source for its beta input, and used inappropriate risk-free rates.[104]

Regarding the Company's 14.27% market rate of return

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[102] Staff Initial Brief 59-60.

[103] See Case 08-E-0539, Consolidated Edison Company of New York, Inc. – Electric Rates, Order Setting Electric Rates 125-126 (issued April 24, 2009) (2008 Con Edison Rate Order).

[104] Staff Initial Brief 63-66.

estimate, relying on language from a Federal Energy Regulatory Commission order, Corning omits the use of a long-term component in its methodology relying wholly on a constant growth analysis of the S&P 500 index derived from short-term earnings. Staff challenges the Company's methodology stating that it is unreasonable to assume that near-term earnings growth forecasts formulated for the next three to six years will last into perpetuity. Additionally, Staff dismisses Corning's use of a beta from Bloomberg noting that the Commission has consistently used Value Line betas based on research that demonstrates the superiority of those betas. Nothing was presented in this case to make us reconsider that use in favor of other beta sources, or even as additional beta sources. We also agree with Staff that a five-year measurement period for beta balances the interests of having a long enough timeframe to produce reliable estimates but using recent enough data to reflect current market conditions. Lastly, we agree with Staff that the best forecast of future interest rates is a no-change forecast. There is no credible evidence that forecasts of changes in interest rates are reliable not just in terms of the amount of a predicted change, but even in the direction of any such change. Accordingly, we affirm the Commission's practice of not relying on any published analysts' interest rate forecasts to determine the risk-free rate, but rather to assume a no-change forecast.

Corning challenges Staff's CAPM result as being too low attributing such result to Staff's exclusive use of Value-Line betas,[105] but a review of the record demonstrates that the Staff methodology used follows Commission precedent as reflected in the rate case decisions that have been issued since the

[105] Corning Initial Brief 62.

Generic Finance Recommended Decision.[106] We agree with Staff and will employ its CAPM as updated.

As the Commission did in Case 16-G-0257 when it considered the litigated record to establish rates for National Fuel Gas, we rely on certain longstanding elements of the Commission's finance methodology: the application of both DCF and CAPM analyses to a representative proxy group of utility companies; the use of a two-stage DCF computation with inputs derived from Value Line; the basing of CAPM results on an average of the outcome from standard and zero-beta models with a risk-free rate based on Treasury bonds, market risk premium provided by Merrill Lynch's Quantitative Profiles, and betas taken from Value Line.

d. DCF/CAPM Weighting

The Commission has expressed its preference for a two-thirds weight of the DCF and a one-third weight to the CAPM results on numerous occasions. Relying on more observable and less subjective inputs, the DCF is superior to the CAPM and our preferred weighting for determining an ultimate ROE recognizes that superiority of the DCF. As Staff discusses in its brief, Corning's issues with the differences between the Company's own CAPM and DCF results are products of questionable inputs that we have rejected in this Order. Were the Company to run their respective calculations using our adopted inputs, it is more than likely that the two results would be more closely aligned. In any event, we see nothing new raised that has not been considered and rejected in past Commission orders on the question of weighting the two methodologies and affirm its use herein.

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[106] Case 91-M-0509, Proceeding on Motion of the Commission to Consider Financial and Regulatory Policies for New York State Utilities, Recommended Decision (issued July 19, 1994).

e. Size Premium

As a final issue, Corning urges the Commission to employ a 50-basis point upward adjustment to our final ROE to account for Corning's small size relative to some other New York investor-owned gas utilities.[107] The Company claims that such an adjustment is warranted because its smaller size makes it less able to weather events that adversely impact its revenues and expenses creating additional risk that should be compensated. In the universe of regulated utilities, difficulties faced by other smaller-sized companies are not present for precisely the reasons cited by Staff, e.g., they are heavily regulated and follow similar accounting procedures to each other, they are required to seek regulatory approval for security issuances, and they are provided just and reasonable rates that can be changed upon a demonstration of inadequacy. Thus, we see no reason based on size-alone to provide a premium to the Company's allowed ROE.

Here, we have already declined to apply numerous inputs used by Corning underlying its requested 10.20% ROE. In doing so, we have affirmed past Commission precedent and decided to apply Staff's application of the Commission's generic finance methodology. In so doing, we are allowing the Company to set rates based on an 8.80% ROE which has been updated from the time of Staff's testimony to reflect the most current financial information available. This result is the product of a rational methodology that creates predictability and certainty and balances all interests involved. As such, our allowed ROE and the other cost of money issues resolved in this section contribute significantly to the rate plan included in this Order and our finding that the rates we are setting are, as a whole,

[107] Corning Initial Brief 65-66.

just and reasonable.

F. Overall Revenue Requirement

All the changes discussed above result in a base rate decrease of $0.766 million. As previously stated, a $1.3 million tax surcredit is expiring and the DRA surcharge is forecast to be reduced by $30,000. These changes result in a total net revenue impact of $505,000, which is an overall revenue increase of 1.77% over the Rate Year. The average annual bill impact on residential customers will be an increase of approximately 2.43% and the average annual bill impact on low income customers will be a decrease of approximately 6.14%. However, as new rates will not go into effect until June 1, 2021, these impacts will need to be compressed into the remaining eight months of the Rate Year. To effectuate this compression, the Company must institute a surcharge, allocated to all service classes based on revenues excluding contract customers, that will collect $311,501 from June 1, 2021, through the end of the Rate Year. The amount is comprised of: 1) the tax sur-credit passed back between February 1, 2021, and May 31, 2021; 2) the residential base revenue decrease that the Company should have implemented beginning February 1, 2021, through May 31, 2021; and 3) the non-residential base revenue decrease that the Company should have implemented beginning February 1, 2021, through May 31, 2021. This surcharge shall expire on January 31, 2022. The Company shall reconcile the amounts collected through the compression surcharge to the amounts that should have been collected if rates had gone into effect on February 1, 2021. The residential base revenue collected through the compression surcharge shall not be included in this reconciliation as it will be reflected in the RDM reconciliation. The reconciliation amount shall be booked

to a regulatory asset or liability account, dependent upon the result of the calculation, for the Commission's future determination.

G. Gas Safety

Staff and the Company are mostly in agreement with the revenue adjustment programs applicable to its gas safety initiatives. These initiatives establish safety performance targets in the areas of Leak Management, Infrastructure Enhancement, Emergency Response, Damage Prevention, and Non-compliance with the Commission's Gas Safety Regulations.[108]

Consistent with other gas utilities, Corning's performance is subject to a maximum negative revenue adjustment of 150 basis points for unsatisfactory performance.[109] The parties agree both to the total amount of revenue exposure and as to how the allocation of those points should be made. Corning also has some metrics by which it can earn positive revenue adjustments. There are some minor differences between the parties as to how to measure performance in certain targets and as to the amount and eligibility for positive adjustments.

As of the end of 2019, Corning's system included approximately 70 miles of leak prone pipe remaining to be replaced. The parties have agreed on requiring the Company to replace ten miles per year, which puts Corning on track to conclude its replacement program in approximately seven years. The parties also agree to a target of replacing a minimum of 250 leak prone services per year, concurrently with the main replacement program, and that all gas meters and service regulators be placed outside a customer's building or structure

[108] See Appendix 7 for a full description of all metrics and programs.

[109] Staff Initial Brief 81-82.

on all new and replacement service installations. The parties also agree that any leaks that Corning need repair in a flood control area may be included as part of the leak prone pipe replacement program. This allowance is for the period addressed in this rate proceeding and may not be extended, explaining that to remove and avoid conflicts with the flood control levees that currently contain leak prone pipe with active leaks, if the length of the pipe required to be replaced or relocated is longer than the actual length of the pipe in the ditch, Corning will be allowed to count the entire length of the pipe installed towards its annual 10 mile replacement target.[110] There is additional agreement on the treatment of incremental costs over the $33.96 cost per foot for systematic replacement of distribution main in calendar year 2021 utilized by the Staff Infrastructure and Operations Panel to calculate the average unit cost and on the maintaining of records of the number of miles and feet of main replaced, specifically in the flood control area.[111] Finally, the parties also agree that Corning be subject to a maximum negative revenue adjustment of 15 basis points[112] for not meeting its targets.[113]

There is one area of dispute as to whether Corning should be provided with a positive revenue adjustment for exceeding its annual leak prone pipe replacement targets.[114] The Company raised this possibility for the first time in rebuttal preventing Staff from addressing it in testimony. In brief, however, Staff does not recommend we adopt any positive

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110 Staff Initial Brief 82-83.

111 Staff Initial Brief 83.

112 All basis points applicable to negative revenue adjustments in this section are assessed on a pre-tax basis.

113 Staff Initial Brief 83.

114 Corning Initial Brief 70-71.

adjustment mechanism for leak prone pipe replacement. Staff relies mostly on its agreement with Corning that allows it to count additional pipe replacement in flood control areas towards its annual replacement goal. Staff notes that this allowance already provides an incentive to the Company and allow it to easily achieve its annual target.[115] We agree and decline to adopt a positive rate adjustment in this particular instance.

For leaks on the Company's system, Corning and Staff agree to total leak backlog targets of 45 at the end of 2021 and 40 at the end of 2022. The Company and Staff also agree for Corning to meet a repairable leak backlog of four leaks or fewer until changed by the Commission. As for an assessed revenue adjustment, Corning agrees to Staff's recommendation of five basis points for the total leak backlog target and ten basis points for the repairable leak backlog target.[116] Again, the two parties disagree on the application of positive revenue adjustments, although in this case they agree that some program of positive adjustments should be included in the rate order.

Staff proposes a tiered approach such that two basis points would be awarded for total year-end leaks between 34 and 26, four basis points for total year-end leaks between 25 and 16, and six basis points for fewer than 16. Corning contests the fairness of increasing the risk attached to potential negative revenue adjustments while reducing the additional earnings attached to superior performance.[117] Corning proposes that the respective tiers be valued at four, six and eight basis points, respectively.[118] Staff notes that its recommended

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[115] Staff Initial Brief 83-84.

[116] Staff Initial Brief 84.

[117] Staff Initial Brief 84-85.

[118] Corning Initial Brief 70.

positive revenue adjustment amounts are commensurate to other New York gas utilities.[119] Corning's fairness argument is tied to the fact that Staff's recommendation has reduced the revenues available to it under its previous rate plan. However, the Company does not dispute Staff's representation regarding similarly situated gas utilities. Accordingly, we adopt Staff's recommendation.

For Damage Prevention, Staff and Corning agree that its existing categorized program be converted into one metric applicable to total damages assessed on a tiered basis.[120] However, the parties disagree on the maximum exposure to which the Company should be subject. Under Staff's recommended program, for the maximum exposure tier, the target is set at a rate in excess of 2.50 damage incidents per 1000 one call tickets with an associated negative revenue adjustment of 20 basis points. For the second tier, the applicable target is between 2.26 and 2.50 incidents per 1000 one call tickets with an associated negative revenue adjustment of ten basis points. For the third tier, the applicable target is between 2.01 and 2.25 incidents per 1000 one call tickets with an associated negative revenue adjustment of five basis points. After a neutral tier whereby no revenue adjustment is made for performance within 1.51 and 2.00 incidents per 1000 one call tickets, the Company would begin to realize a positive revenue adjustment of five basis points for performance within 1.26 and 1.50 incidents, and ten basis points for a rate below 1.26 incidents.[121]

Corning argues that 20 basis points is too high and

[119] Staff Initial Brief 85.

[120] Corning Initial Brief 73.

[121] Staff Initial Brief 85-86.

proposes a maximum exposure of fifteen basis points. The Company relies on its small size asserting that any change in the number of total damages results in a large impact on its overall damage performance.[122] Staff does not specifically respond to Corning's assertion, but instead observes that when measured against the 2019 statewide average, Corning's performance for overall damages was at a rate of 2.10 per 1000 one-call tickets, worse than the average statewide performance level of 1.84 per 1000 one-call tickets of other gas utilities. Citing to the Company's historic performance, Staff asserts that its recommendation is designed to bring Corning closer to the statewide average.[123] We share Staff's concern regarding the Company's standing vis-à-vis its peer utilities. Accordingly, we adopt Staff's recommended exposure levels, as well as its positive incentive levels to which Corning did not object.

For Corning's emergency response program, Staff and the Company agree to maintain the current targets which require Corning to respond within 30 minutes to 75% of all gas leak, odor, and emergency calls; respond within 45 minutes to 90% of all gas leak, odor, and emergency calls, and respond within 60 minutes to 95% of all gas leak, odor, and emergency calls.[124] Staff has recommended an increase in the maximum exposure applicable to these tiers to twelve, eight, and five from the Company's last rate plan which applied six, four and two, respectively. Staff posits that such an increase will provide an incentive for Corning not to backslide from its current performance which was compliant.[125] Corning counters that there

[122] Corning Initial Brief 73.

[123] Staff Initial Brief 86.

[124] Staff Initial Brief 86-87.

[125] Staff Initial Brief 87.

is no reason to believe that the Company's performance will decrease.[126] Although we agree with Staff's recommended increase in exposure, we think the more compelling reason to do so than Staff's backsliding prevention concern is because such an increase better reflects the Commission's elevated concern with the importance of responding to an emergency situation, particularly in the context of retaining a 150 basis point total maximum exposure, but reallocating that exposure among the complete profile of Corning's gas safety programs.

Finally, for the outcomes of field audits performed by the Department's Gas Pipeline Safety Staff to determine compliance with the Commission's pipeline safety rules and regulations contained in 16 NYCRR Parts 255, 261 and 753, Corning and Staff are in agreement across the program. As an initial matter, for violations that occurred in previous years, Corning owes to customers $153,000 of which the parties to propose to invest $75,000 in the implementation of a Residential Methane Detector Program.[127] We agree.

As to the specifics of violations of the Commission's rules and regulations, the parties agree on a negative revenue adjustment maximum exposure of 75 basis points per year, which is consistent with the pipeline safety performance measure metrics for other New York gas utilities.[128] The 75 basis points would be assessed as follows: for record audits, the first five high risk violations would not subject the Company to any adjustment; from the sixth to the 20th high-risk violations, the Company would incur one-half basis point per violation; and for each high-risk violation greater than 20, the Company would

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[126] Corning Initial Brief 73.

[127] Staff Initial Brief 88, 94-95; Corning Initial Brief 75-76.

[128] Corning Initial Brief 73.

incur one basis point per violation. For the first 15 other risk violations, the Company would not be subject to an adjustment; and for each other risk violation greater than 15, the Company would incur a negative revenue adjustment of one-fourth of a basis point per violation. For field audits and investigations, the Company would incur a negative revenue adjustment of one-half a basis point for each of the first 20 high-risk violations; for each high-risk violation in excess of 20, the Company would incur a negative revenue adjustment of one basis point per violation; and for all other risk violations, the Company would incur a negative revenue adjustment of one-fourth basis point. In addition, for each audit year, a cap on the total record audit violation count of ten basis points will apply to each of the code sections identified in Hearing Exhibit 44 which lists several discrete code sections, with any additional noncompliance of those sections subject to further review and action. As explained by Staff, in any case where the Company has more than ten violations of a single code section, the Company is to develop a corrective action plan to ensure that violations do not continue and should the Company fail to comply with its corrective action plan, the number of violations of a given code section that are in excess of ten would be included with the remainder of the violations being considered for the compliance measure, thereby increasing the basis points at risk in a potential negative revenue adjustment. While the corrective action plan is intended to avoid the need for formal, intensive penalty actions against the Company for each noncompliance, it does not replace the Commission's ability to pursue a penalty action should the need for such action become apparent so as to compel compliance.[129]

[129] Staff Initial Brief 88-90.

H. Customer Service and Low Income

Since 2017, the Commission has been working with Office of Consumer Services to bring consistency across the State's utilities to their Customer Service Performance Indicator (CSPI) programs, including consolidating the names of the different metrics as well as the timing of annual reporting. We continue that trend and adopt Staff's general recommendations, to which the Company agrees, as to the names and applicability of the various metrics, the requirement that Corning's annual performance review be done on a calendar year basis, and to apply negative revenue adjustments for each metric that are measured in terms of pre-tax basis points rather than specific dollar amounts.[130]

The Company and Staff agree to maintain the current target level of three or fewer customer complaints to avoid a negative revenue adjustment.[131] Additionally, the Company and Staff agree to a Customer Satisfaction Survey minimum score of 87.7% to avoid a negative revenue adjustment. Should its score fall between 86.7% and less than or equal to 87.7%, Corning would be subject to a five-basis point adjustment, ten basis points for a score between 85.7% and less than 86.7%, and fifteen basis points for a score less than 85.7%.[132]

For Appointments Kept, Corning agrees to Staff's recommendation at this time to develop written policies and procedures for scheduling, logging, tracking and verification of service appointments and missed appointment information. Corning also will inform customers that they will receive a $25 credit for a missed appointment either at the time the

130 Corning Initial Brief 78.

131 Staff Initial Brief 98.

132 Staff Initial Brief 98-99.

appointment is made or when confirming the scheduled appointment.[133] Corning should file its proposed policies and procedures with the Secretary within 30 days after issuance of this Order.

While the parties have agreed that Corning will add an Arrearage component to its existing Residential Service Terminations and Uncollectibles metric, Staff and the Company disagree on the targets that would be applied and the associated positive and negative revenue adjustments that would be applied against performance.[134] We, however, will pause this mechanism because, on May 11, 2021, Governor Cuomo signed into law an extension to the moratorium on utility terminations for residential and small businesses for a period of 180 days after the COVID-19 state of emergency is lifted or 180 days after December 31, 2021, whichever is earlier. The moratorium may be in effect much of the Company's rate year, which will impact company operations. Corning's actual termination, arrearage and uncollectible performances will be impacted by the legislation and its performance will not be comparable to either Staff or the Company's proposed performance targets. Staff, the Company and parties can explore reinstating this mechanism in the Company's next rate filing.[135]

The parties are also in agreement that the Company will file a feasibility proposal for an Electronic Deferred Payment Agreements (e-DPA) program.[136] We take no further action on this item, noting that only a proposal is required here. Thus, issues raised by Coring as to its Customer Information

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[133] Corning Initial Brief 79.

[134] Corning Initial Brief 79.

[135] See Appendix 8 for the CSPI metrics.

[136] Corning Initial Brief 82.

System not being connected to the Company web page for a secure portal for signatures and any alternatives may be raised in the filed proposal. The parties also agree as to securing support for its Customer Information System. Corning's proposal should be included in the Company's next rate filing, unless such filing is not made within 60 days after issuance of this Order, in which case the proposal should be filed within the same 60 days as a stand-alone compliance item.

Lastly, Corning agrees with Staff's recommendations to increase the existing low-income discount from $8.00 to $16.00 per month and its overall Low-Income Program budget to $250,000.[137]

I. Rate Design Issues

1. Embedded Cost of Service Study

The Company provided an embedded cost of service studay ("ECOS Study") allocating the Company's revenues and expenses to each service class. The ECOS study calculated a rate of return by class for guidance in revenue allocation and rate design, and allocated costs between customer-related (exclusive of demand) and demand-related costs. The ECOS Study classified gas distribution main costs as customer-related on the basis of a minimum system study, a 2-inch main system that would be required without consideration of any demand.[138]

Staff criticized the minimum system study on the basis that the five years of data on 2-inch mains were limited and not reflective of the Company's entire system cost. Staff recommends that the Company use in future cases the average installation cost for 2-inch mains based on the Company's entire

[137] Corning Initial Brief 83.

[138] Tr. 279-289.

plant in service, not just the last five years of costs. Staff further proposes that if the relevant data are unavailable, the Company usea state-wide average customer componenet of the minimum system study to allocate distribution main costs.[139] The Company responded in rebuttal testimony that only a few years of data are necessary for this calculation and that a state-wide average would be meaningless.[140]

Because we are not using the ECOS study to design rates in this case, we do not need to resolve this issue here. We urge the Company to work with Staff prior to filing its next rate case to reach a mutual agreement on the data to use for the minimum system study. If agreement is not reached, we expect to see testimony on this matter in the next case, and we will address the issue at that time.

Multiple Intervenors objects to the Company's use of an "adjusted customer allocation factor" to allocate the costs of mains larger than two inches as this underallocates costs to small customers by attempting to combine the number of customers with the aggregation of larger loads. Multiple Intervenors witness Baudino testified that the Company's adjusted customer allocation factor was highly unusual.[141] The Company took issue with Mr. Baudino's illustrative alternative calculation but did not directly address Mr. Baudino's objections to the adjusted customer allocation factor.[142]

We see merit in Multiple Intervenors' objections to the adjusted customer allocation factor, but because we are not using the ECOS study for rate design in this case, this issue

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[139] Tr. 1018-1020.

[140] Tr. 311-313.

[141] Tr. 882-885.

[142] Tr. 314.

can be addressed if necessary in the Company's next rate case.

2. Revenue Allocation

Because of the unresolved disputes about the details of the ECOS study and because the revenue requirement increase we are authorizing in this case is relatively small, we will allocate the revenue requirement increase to each class of service on a uniform basis as proposed by the Company[143] with one exception: we will allocate a slightly larger increase to SC 8 Hamondsport Transportation to move it closer to SC 6 Commercial Transportation, which has similar characteristics. This adjustment was recommended by Staff[144] and not contested by the Company.[145] UIU also concurs with a uniform increase as adjusted by Staff.[146] Multiple Intervenors objects to a uniform rate increase and proposes adjustments to rate design based on the ECOS study,[147] but given the multiple criticisms of the ECOS study and the small revenue increase allowed in this case, we will adopt Staff's position.

3. Rate Design

The Company proposed increases in minimum charges of appproximately 25%.[148] Staff proposed proportional increases across the board to minimum customer charges and all other volumetric charges based on the revenue requirement authorized in this case.[149] The Company accepted Staff's proposal in its Reply Brief.[150] We accept the agreement of the parties. The

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143 Company Reply Brief at 75.

144 Staff Initial Brief at 78.

145 Company Reply Brief at 75.

146 UIU Initial Brief at 10-11.

147 Multiple Intervenors Initial Brief at 7-9.

148 Hearing Exh. 11 (CNG-10, PMN-5, p. 1)

149 Hearing Exh. 46 (SRP-4); Staff Initial Brief at 79.

150 Company Reply Brief at 76.

final revenue allocation is contained in Appendix 9.

4. Lost and Unaccounted for Gas

For the last two rate proceedings, the Company has operated under an incentive mechanism for Lost and Unaccounted for ("LAUF") gas, which is calculated by subtracting metered deliveries from metered supplies. The mechanism is based on a LAUF Factor of Adjustment, which contains a deadband above which the Company incurs a penalty, and below which the Company achieves an incentive. Within the deadband the Company recovers its actual commodity costs. The current Factor of Adjustment is 1.0037, and the deadband is from 1.0 to 1.0160. The Company recommended no change in these amounts. Staff proposed to reset the Factor of Adjustment to 1.0027 based on the most recent five year period as the Commission did in the last two rate cases, and to reset the deadband at 1.0 to 1.0192.[151] The Company accepted these adjustments in its Reply Brief,[152] and we accept the agreement of the parties.

V. CONCLUSION

We find that the rates and rate plan adopted herein provide just and reasonable rates, terms and conditions, and, consistent with the discussion herein, are in the public interest.

The Commission orders:

1. Corning Natural Gas Corporation is directed to file cancellation supplements, effective on not less than one day's notice, on or before May 26, 2021, cancelling the tariff amendments and supplements listed in Appendix 1 to this Order.

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[151] Tr. 1031-1032.

[152] Company Reply Brief at 76.

2. Corning Natural Gas Corporation is directed to file, on not less than five days' notice, such further tariff revisions as are necessary to effectuate the provisions adopted by this Order, including a total net revenue increase of $505,000 to take effect June 1, 2021, as detailed in Appendix 2 to this Order. Corning Natural Gas Corporation shall serve copies of its filing on all active parties in these cases. Any comments on the compliance filing must be received at the Commission's offices within 14 days of service. The amendments specified in the compliance filing shall not become effective on a permanent basis until approved by the Commission.

3. The requirement of Section 66(12)(b) of the Public Service Law that newspaper publication be completed prior to the effective date of the proposed amendments directed in Clause 2 above is waived and Corning Natural Gas Corporation is directed to file with the Commission, not later than six weeks following the amendments' effective date, proof that a notice to the public of the changes made by the amendments has been published once a week for four successive weeks in newspapers having general circulation in the areas affected by the amendments.

4. Corning Natural Gas Corporation is directed to file within 90 days after the end of each calendar year, beginning with 2021, capital expense and variance reports as described in the body of this Order.

5. The Petition of Corning Natural Gas Corporation to Defer Leak Survey and Repair Costs Over and Above the Level Last Established in Rates in Case 16-G-0204 is denied.

6. Corning Natural Gas Corporation shall, within 30 days of the date of issuance of this Order, file proposed policies and procedures with respect to missed appointments and a customer credit of $25 for missed appointments.

7. Corning Natural Gas Corporation shall, either in its next rate case filing or within 60 days of the issuance of this Order, whichever first occurs, file a proposal for an electronic deferred payment agreements program.

8. These proceedings are continued.

By the Commission,

(SIGNED) MICHELLE L. PHILLIPS
Secretary

CASE 20-G-0101 APPENDIX 1

SUBJECT: Filing by CORNING NATURAL GAS CORPORATION

Amendments to Schedule P.S.C. No. 7 – Gas

Seventh Revised Leaves Nos. 153, 157, 160, 162, 165, 197
Ninth Revised Leaf No. 155

Suspension Supplement Nos. 7,8,9

Corning Natural Gas Corporation
Case 20-G-0101
Statement of Operating Income
For the Rate Year Ending January 31, 2022

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission	Revenue Requirement Adjustment	Rate Year with Revenue Increase
Operating Revenues	$ 26,827,587		$ -	$ 26,827,587	$ (765,664)	$ 26,061,923
Purchased Gas	7,227,396		-	7,227,396	-	7,227,396
Operating & Maintenance Expense	9,270,709	1	(697,204)	8,573,505	(3,555)	8,569,950
Depreciation Expense	2,525,056	2	(534,058)	1,990,998	-	1,990,998
Accelerated Recovery of Plant	177,222		-	177,222		177,222
Taxes Other Than FIT	3,153,509	3	(15,303)	3,138,206	(9,687)	3,128,519
Total Operating Expense	22,353,891		(1,246,565)	21,107,326	(13,242)	21,094,084
Operating Income Before Income Taxes	4,473,696		1,246,565	5,720,261	(752,422)	4,967,839
State Income Taxes						
Current	261,981		52,202	314,183	(48,907)	265,275
Deferred	(59,086)	4	26,370	(32,716)	-	(32,716)
Total State Income Taxes	202,895		78,572	281,467	(48,907)	232,560
Federal Income Taxes						
Current	1,062,564		188,849	1,251,413	(147,738)	1,103,675
Deferred	(762,190)	5	54,037	(708,152)	-	(708,152)
Total Federal Income Taxes	300,375		242,887	543,261	(147,738)	395,523
Operating Income	**3,970,427**		**925,106**	**4,895,533**	**(555,776)**	**4,339,757**
Rate Base	$ 68,650,777	6	$ 466,132	$ 69,116,909		$ 69,116,909
Rate of Return	**5.78%**			**7.08%**		**6.28%**

Corning Natural Gas Corporation
Case 20-G-0101
Schedule of Revenues and Operating and Maintenance Expenses
For the Rate Year Ending January 31, 2022

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
Operating Revenues				
Total Delivery Revenues	$ 18,062,487			$ 18,062,487
Merchant Function Charge	246,869			246,869
Total Base Revenues	18,309,356		-	18,309,356
Gas Costs	7,227,396			7,227,396
Revenue Taxes	322,803			322,803
NYSE&G	421,657			421,657
Gas Operating Revenues	26,281,212		-	26,281,212
Other Gas Revenues				
Customer Discounts Forfeited	101,031			101,031
Reconnect Fees	1,992			1,992
Misc. Revenues	2,929			2,929
Local Production Shortfall	213,114			213,114
Local Production - Transportation Short Fall	50,088			50,088
Accelerated Recovery Plant	177,222			177,222
Total Other Gas Revenues	546,375		-	546,375
Operating Revenues	**$ 26,827,587**		**$ -**	**$ 26,827,587**

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
Operating Expenses				
Purchased Gas Other	$ (21,142)		$ -	$ (21,142)
Direct Labor	3,302,952	1A	(150,181)	3,152,771
Supervisory & Indirect Labor	552,394			552,394
Insurance Costs	1,389,575	1B	(82,931)	1,306,644
Regulatory Costs	493,775	1C	(405,698)	88,077
Pensions and OPEBS	1			1
Pension Current	1,072,432			1,072,432
Pension Amortization	222,637	1D	(111,318)	111,319
OPEB Current	64,968			64,968
OPEB Amortization	(72,626)	1E	36,313	(36,313)
Uncollectible Accounts	118,564			118,564
Low Income Program	250,000			250,000
Debit Card & Credit Card fees	44,000	1F	8,242	52,242
Building Services	112,305			112,305
Transportation	195,546			195,546
Outside Services	476,425	1G	(72,000)	404,425
Inventory	166,307			166,307
Other O&M Costs	970,566	1H	80,369	1,050,935
Productivity Adjustment	(67,970)			(67,970)
Total Operating Expense	**$ 9,270,709**		**$ (697,204)**	**$ 8,573,505**

Corning Natural Gas Corporation
Case 20-G-0101
Depreciation Summary
For the Rate Year Ending January 31, 2022

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
Depreciation Expense	2,525,056	2	(534,058)	$ 1,990,998
Depreciation (Bath Line Project 11-G-0280 rate case)	177,222			177,222
Total Depreciation	**$ 2,702,278**		**$ (534,058)**	**$ 2,168,220**

Appendix 2
Schedule 4 of 9

Corning Natural Gas Corporation
Case 20-G-0101
Taxes Other than Income Taxes
For the Rate Year Ending January 31, 2022

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
Property Tax	$ 2,618,171			$ 2,618,171
Payroll Taxes	212,535	3A	(15,303)	197,232
Revenue Taxes	322,803			322,803
Taxes Other Than Income Taxes	**$ 3,153,509**		**$ (15,303)**	**$ 3,138,206**

Corning Natural Gas Corporation
Case 20-G-0101
Rate Base Summary
For the Rate Year Ending January 31, 2022

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
Net Utility Plant				
Plant in Service	$ 98,562,604	6A	104,242	$ 98,666,846
CWIP-Non Interest Bearing	3,182,055			3,182,055
Plant Allocated to Subsidiaries Operations	(817,715)			(817,715)
Plant Reserves				
Normal Depreciation	(26,268,942)	6B	253,197	(26,015,745)
Accelerated Recovery-Root Well/ Upgrades	(2,689,522)			(2,689,522)
Accelerated Recovery-Virgil	(1,000,000)			(1,000,000)
Accelerated Recovery-Bath	(1,569,704)			(1,569,704)
Accelerated Recovery-Other	(52,724)			(52,724)
Total Net Plant	69,346,052		357,439	69,703,491
Working Capital				
Material and Supplies	1,754,033			1,754,033
Prepayments	1,588,832			1,588,832
Cash Working Capital	926,215	6C	(27,063)	899,152
Total Working Capital	4,269,079		(27,063)	4,242,017
Deferred Debits	1,498,815	6D	164,637	1,663,452
Deferred Credits	(382,449)	6E	(78,677)	(461,126)
Unamortized Debt Discount & Expense	94,284			94,284
Accumulated Deferred Income Taxes	(9,946,487)	6F	49,796	(9,896,692)
Total Rate Base	64,879,295		466,132	65,345,427
Earnings Based Capitalization Adjustment	3,771,482			3,771,482
Rate Base as Adjusted	**$ 68,650,777**		**$ 466,132**	**$ 69,116,909**

Corning Natural Gas Corporation
Case 20-G-0101
Calculation of State Income Taxes
For the Rate Year Ending January 31, 2022

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
Operating Income Before Income Taxes	$ 4,473,696		$ 1,246,565	$ 5,720,261
Interest Expense	(1,382,499)		(37,760)	(1,420,259)
Amort of Excess Book Depreciation Reserve	(151,619)			(151,619)
ADR Normalized	18,100			18,100
Book Depreciation Expense	5,158,266			5,158,266
Deduct Tax Depreciation (less accelerated)	(4,659,039)			(4,659,039)
Rate Case Cost 2016	95,000		(82,333)	12,667
Amortization of Gas Specialist	(3,997)		2,221	(1,776)
Other Surcharges Applied to Plant	177,222			177,222
Deferred Net Plant Due	(24,624)		13,674	(10,950)
Rate Case 2020	211,967		(148,377)	63,590
Safety & Reliability Shortfall	29,372		(14,686)	14,686
Customer Affiliate Allocation Shortfall	17,557		(8,778)	8,779
Customer Make Whole Increase	18,397		(9,198)	9,199
Leak Repair/Survey	(0)			(0)
Pass Back of Interest on Over Collection	(57,912)			(57,912)
Fixed Interest	119,561		(59,781)	59,780
Customer Incentive	12,800		(6,400)	6,400
2019 mismarks	-		(2,011)	(2,011)
Leak backlog, total damages and mismarks for 2016, 2017 and 2018	-		(29,372)	(29,372)
Updated NRA balance	-		(14,520)	(14,520)
PP OPEB	-		(38,608)	(38,608)
Deferred Credits - 2016 Regulatory Liability	(4,704)		(3,137)	(7,841)
Deferred Credits - 2017 Regulatory Liability	(3,671)		(2,447)	(6,118)
Deferred Credits - 2018 Regulatory Liability	(3,397)		(11,945)	(15,342)
Deferred Credits - 2019 Regulatory Liability	(10,000)		10,000	0
Total Adjustments for Taxable Income	(443,221)		(443,458)	(886,679)
	939,278			533,580
Tax Income	$ 4,030,475		$ 803,107	$ 4,833,582
Rate	6.50%			6.50%
Current SIT	261,981		52,202	314,183
Total Current State Income Tax	**$ 261,981**		**$ 52,202**	**$ 314,183**

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
ADR Normalized	(1,176)			(1,176)
ACRS Normalized	(32,450)			(32,450)
Other Surcharges applied to plant	(11,519)			(11,519)
Deferred Net Plant Due	1,601		(889)	712
Rate Case 2016	(6,175)		5,352	(823)
Safety & Reliability Shortfall	(1,909)		955	(955)
Customer Affiliate Allocation Shortfall	(1,141)		571	(571)
Customer Make Whole Increase	(1,196)		598	(598)
Gas Specialist	260		(144)	115
Leak Repair/Survey	0		-	0
Pass Back of Interest on Over Collection	3,764		-	3,764
Fixed Interest	(7,771)		3,886	(3,886)
Customer Incentive	(832)		416	(416)
Def Debit-FIT Refund	(0)		-	(0)
2019 mismarks	-		131	131
Leak backlog, total damages and mismarks for 2016, 2017 and 2018	-		1,909	1,909
Updated NRA balance	-		944	944
PP OPEB	-		2,510	2,510
Def Debit-Rate Case 2020	(13,778)		9,645	(4,133)
Deferred Credits - 2016 Regulatory Liability	306		204	510
Deferred Credits - 2017 Regulatory Liability	239		159	398
Deferred Credits - 2018 Regulatory Liability	221		776	997
Deferred Credits - 2019 Regulatory Liability	650		(650)	(0)
Amortization of Accelerated Recovery Deferred Tax	11,822			11,822
Total Deferred State Income Tax	**$ (59,086)**	4A	**$ 26,370**	**$ (32,716)**

Appendix 2
Schedule 7 of 9
Page 1 of 2

Corning Natural Gas Corporation
Case 20-G-0101
Calculation of Federal Income Taxes
For the Rate Year Ending January 31, 2022

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
Operating Income Before Income Taxes	$ 4,473,696		$ 1,246,565	$ 5,720,261
SIT Current	(261,981)		(52,202)	(314,183)
Interest Expense	(1,382,499)		(37,760)	(1,420,259)
Amort of Excess Book Depreciation Reserve	(151,619)			(151,619)
ADR Normalized	18,100			18,100
Deduct Tax Depreciation (less accelerated)	(3,367,705)			(3,367,705)
Rate Case 2016	95,000		(82,333)	12,667
Other Surcharges applied to Plant	177,222			177,222
Safety & Reliability Shortfall	29,372		(14,686)	14,686
Customer Affiliate Allocation Shortfall	17,557		(8,778)	8,779
Customer Make Whole Increase	18,397		(9,198)	9,199
Amortization of Specialist Wage Diff	(3,997)		2,221	(1,776)
Leak Repair/Survey	(0)			(0)
Pass Back of Interest on Over Collection	(57,912)			(57,912)
Fixed Interest	119,561		(59,781)	59,780
Customer Incentive	12,800		(6,400)	6,400
Def Debit-Rate Case 2020	211,967			211,967
2019 mismarks	-		(1,207)	(1,207)
Leak backlog, total damages and mismarks for 2016, 2017 and 2018	-		(29,372)	(29,372)
PP OPEB	-		(38,608)	(38,608)
Updated NRA balance	-		(15,324)	(15,324)
Deferred Credits - 2015 Regulatory Liability	0			0
Deferred Credits - 2016 Regulatory Liability	(4,704)		(3,137)	(7,841)
Deferred Credits - 2017 Regulatory Liability	(3,671)		(2,447)	(6,118)
Deferred Credits - 2018 Regulatory Liability	(3,397)		(11,945)	(15,342)
Deferred Credits - 2019 Regulatory Liability	(10,000)		10,000	0
Deferred Net Plant Due	(24,624)		13,674	(10,950)
Book Depreciation -includes clearing accounts	5,158,266			5,158,266
Total Adjustments for Taxable Income	586,133		(347,283)	238,850
Tax Income	5,059,829		899,282	5,959,111
Rate	21.00%		21.00%	21.00%
Current Federal Income Tax	**$ 1,062,564**		**$ 188,849**	**$ 1,251,413**

	Rate Year As Adjusted Per Staff	Adj No.	Commission Adjustments	Rate Year As Adjusted By the Commission
ADR Normalized	(3,801)			(3,801)
ACRS Normalized	(376,018)			(376,018)
Other Surcharges Applied to Plant	(37,217)			(37,217)
Deferred Net Plant Due	5,171		(2,872)	2,300
Rate Case 2016	(19,950)		17,290	(2,660)
Safety & Reliability Shortfall	(6,168)		3,084	(3,084)
Customer Affiliate Allocation Shortfall	(3,687)		1,843	(1,844)
Customer Make Whole Increase	(3,863)		1,932	(1,932)
Gas Specialist	839		(466)	373
Leak Repair/Survey	-			-
Prior Year Pension Recoverable Costs	(0)		-	(0)
Amortization of Prior Period OPEB Over-Collection	(0)		-	(0)
Pass Back of Interest on Over Collection	12,162		-	12,162
Fixed Interest	(25,108)		12,554	(12,554)
Customer Incentive	(2,688)		1,344	(1,344)
Def Debit-Rate Case 2020	(44,513)		-	(44,513)
2019 mismarks	-		253	253
Leak backlog, total damages and mismarks for 2016, 2017 and 2018	-		6,168	6,168
Updated NRA balance	-		3,218	3,218
Deferred Credits - 2016 Regulatory Liability	988		659	1,647
Deferred Credits - 2017 Regulatory Liability	771		514	1,285
Deferred Credits - 2018 Regulatory Liability	713		2,508	3,222
Deferred Credits - 2019 Regulatory Liability	2,100		(2,100)	(0)
PP OPEB	-		8,108	8,108
Amortization of Accelerated Recovery Deferred Tax	38,194			38,194
Regulatory Tax Asset Protected Rates	119,231			119,231
Regulatory Tax Asset Unprotected Rates	(38,611)			(38,611)
Regulatory Incremental Tax Asset Unprotected	(260,835)			(260,835)
Regulatory Incremental Tax Asset Protected	1,859			1,859
Deferred Regulatory Liability Current FIT Due	(139,313)			(139,313)
Deferred Regulatory Liability Depreciation FIT	(295,045)			(295,045)
Deferred Regulatory Liability FIT Other	752,350			752,350
Adjust amortization of excess ADFIT protected	66,952			66,952
Adjust amortization of excess ADFIT unprotected	(506,703)			(506,703)
Adjust amortization of excess ADFIT unprotected - CIAC	-		-	-
Total Deferred FIT	**$ (762,190)**	5A	**$ 54,037**	**$ (708,152)**

Corning Natural Gas Corporation
Case 20-G-0101
Capital Structure
For the Rate Year Ending January 31, 2022

Corning Natural Gas Corporation
Case 20-G-0101
Summary of Adjustments
For the Rate Year Ending January 31, 2022

Adj No.	Description of Adjustment	Commission Adjustments	Total Amount
Adj. 1	**Operations and Maintenance**		
A.	**Direct Labor**		
(1)	To eliminate management wage increases	(5,139)	
(2)	To update overtime pay for union contract	3,258	
(3)	To update vacation pay for union contract	2,557	
(4)	To reflect union wage increases of 3%	18,923	
(5)	To remove allowance for four new hires	(169,780)	(150,181)
B.	**Insurance**		
(1)	To reduce health insurance related to removal of four hires	(77,680)	
(2)	To reduce dental insurance related to removal of four hires	(5,251)	(82,931)
C.	**Regulatory**		
(1)	To reflect amortization of Prior Period OPEB deferral over 3 years	(38,608)	
(2)	To reflect amortization of 2016, 2017, 2018 NRAs deferral over 3 years	(11,749)	
(3)	To reflect amortization of new 2019 NRA deferral over 3 years	(804)	
(4)	To reflect amortization of 2016 NRA deferral over 3 years	(3,137)	
(5)	To reflect amortization of 2017 NRA deferral over 3 years	(2,447)	
(6)	To reflect amortization of 2018 NRA deferral over 3 years	(11,945)	
(7)	To reflect amortization of Gas Supply Specialist deferral over 3 years	2,221	
(8)	To reflect amortization of Net Plant deferral over 3 years	13,674	
(9)	To reflect amortization of 2016 Rate Case deferral over 10 years	(82,333)	
(10)	To reflect amortization of Fixed Interest deferral over 10 years	(59,781)	
(11)	To reflect amortization of Customer Incentive deferral over 10 years	(6,400)	
(12)	years	(14,686)	
(13)	To reflect amortization of Customer Affiliate Allocation Shortfall deferral over 10 years	(8,778)	
(14)	To reflect amortization of Customer Make Whole Increase deferral over 10 years	(9,198)	
(15)	To reflect amortization of Rate Case 2020 deferral over 10 years	(148,377)	
(16)	To include leak backlog, total damages and mismarks NRA deferrals for 2016, 2017 and 2018	(17,623)	
(17)	To include updated NRA balance	(14,520)	
(18)	To include removal of Company's 2019 NRA deferral estimate	10,000	
(19)	To include 2019 mismark NRA deferral	(1,207)	(405,698)
D.	**Pension-Amortization**		
(1)	To reflect amortization of pension deferral over 10 years		(111,318)
E.	**OPEB-Amortization**		
(1)	To reflect amortization of OPEB deferral over 10 years		36,313
F.	**Debit Card & Credit Card Fees**		
(1)	To update estimated vendor costs		8,242
G.	**Outside Services**		
(1)	To remove allowance for the IT consultant		(72,000)
H.	**Other O&M**		
(1)	To update for the latest construction overhead rate		80,369
	Total O&M Expense Adjustments		(697,204)
Adj. 2	**Depreciation Expense**		
(1)	To reflect correction to depreciation expense	(119,845)	
(2)	To remove the allowance for accelerated depreciation of leak prone pipe	(414,213)	(534,058)
Adj. 3	**Taxes Other Income Taxes**		
A.	**Payroll Tax**		
(1)	To track labor adjustments		(15,303)
	Total Taxes other than Income Tax Adjustments		(15,303)

Adj. 4	**New York State Income Tax**		
A.	**Deferred Taxes**		
(1)	To track deferral adjustments		26,370
Adj. 5	**FED Income Tax**		
A.	**Deferred Taxes**		
(1)	To track deferral adjustments		31,511
Adj. 6	**Rate Base**		
A.	**Net Utility Plant**		
(1)	To correct for errors in Company's plant model		104,242
B.	**Plant Reserves**		
(1)	To reflect correction to accumulated depreciation	46,091	
(2)	To remove the allowance for accelerated depreciation of leak prone pipe	207,106	253,197
C.	**Cash Working Capital**		
(1)	To track adjustment to working capital		(27,063)
D.	**Deferred Debits**		
(1)	To reflect amortization of 2016 Rate Case deferral over 10 years	41,027	
(2)	To reflect amortization of Fixed Interest deferral over 10 years	29,890	
(3)	To reflect amortization of Customer Incentive deferral over 10 years	3,200	
(4)	years	7,343	
(5)	To reflect amortization of Customer Affiliate Allocation Shortfall deferral over 10 years	4,389	
(6)	To reflect amortization of Customer Make Whole Increase deferral over 10 years	4,600	
(7)	To reflect amortization of Rate Case 2020 deferral over 10 years	74,188	164,637
E.	**Deferred Credits**		
(1)	To reflect amortization of Prior Period OPEB deferral over 3 years	19,304	
(2)	To reflect amortization of 2016, 2017, 2018 NRAs deferral over 3 years	5,875	
(3)	To reflect amortization of new 2019 NRA deferral over 3 years	403	
(4)	To reflect amortization of 2016 NRA deferral over 3 years	1,568	
(5)	To reflect amortization of 2017 NRA deferral over 3 years	1,224	
(6)	To reflect amortization of 2018 NRA deferral over 3 years	5,972	
(7)	To reflect amortization of Gas Supply Specialist deferral over 3 years	(1,110)	
(8)	To reflect amortization of Net Plant deferral over 3 years	(6,837)	
(9)	To include leak backlog, total damages and mismarks NRA deferrals for 2016, 2017 and 2018	(79,304)	
(10)	To include updated NRA balance	(65,341)	
(11)	To include removal of Company's 2019 NRA deferral estimate	45,000	
(12)	To include 2019 mismark NRA deferral	(5,431)	(78,677)
F.	**Deferred Taxes Amount**		
(1)	To reflect the ADSIT impact related to the depreciation adjustments	17,357	
(2)	To reflect the ADFIT impact related to the depreciation adjustments	56,076	
(3)	To reflect amortization of Prior Period OPEB deferral over 3 years	(5,309)	
(4)	To reflect amortization of 2016, 2017, 2018 NRAs deferral over 3 years	(1,615)	
(5)	To reflect amortization of new 2019 NRA deferral over 3 years	(110)	
(6)	To reflect amortization of 2016 NRA deferral over 3 years	(431)	
(7)	To reflect amortization of 2017 NRA deferral over 3 years	(336)	
(8)	To reflect amortization of 2018 NRA deferral over 3 years	(1,642)	
(9)	To reflect amortization of Gas Supply Specialist deferral over 3 years	305	
(10)	To reflect amortization of Net Plant deferral over 3 years	1,880	
(11)	To reflect amortization of 2016 Rate Case deferral over 10 years	(11,282)	
(12)	To reflect amortization of Fixed Interest deferral over 10 years	(8,220)	
(13)	To reflect amortization of Customer Incentive deferral over 10 years	(880)	
(14)	years	(2,019)	
(15)	To reflect amortization of Customer Affiliate Allocation Shortfall deferral over 10 years	(1,207)	
(16)	To reflect amortization of Customer Make Whole Increase deferral over 10 years	(1,265)	
(17)	To reflect amortization of Rate Case 2020 deferral over 10 years	(20,401)	
(18)	To include leak backlog, total damages and mismarks NRA deferrals for 2016, 2017 and 2018	21,808	
(19)	To include updated NRA balance	17,969	
(20)	To include removal of Company's 2019 NRA deferral estimate	(12,375)	
(21)	To include 2019 mismark NRA deferral	1,493	49,796

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Appendix 3
Schedule 1
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Corning Natural Gas Corporation
Deferred Debits and Credits
For the Rate Year Ending January 31, 2022

Deferred Debits

	Balance as of 9/30/19	Number of Years of Amortization	Amortization Expense
Fixed Interest	$ 597,803	10	$ (59,780)
Customer Incentive	64,000	10	(6,400)
Safety & Reliability Shortfall	146,859	10	(14,686)
Customer Affiliate Allocation Shortfall	87,785	10	(8,779)
Customer Make Whole Increase	91,987	10	(9,199)
Rate Case 2020	635,900	10	(63,590)
Rate Case 2016	126,667	10	(12,667)
Total Deferred Debits	**$ 1,751,002**		**$ (175,099)**
Pension Deferral	**$ 1,113,185**		**$ (111,319)**
Total Amortization Expense			***$ (286,418)***

Deferred Credits

	Balance as of 9/30/19	Number of Years of Amortization	Amortization Expense
Prior Period OPEB Interest Due Customers	$ (289,558)	3	$ 96,519
Amortization of Gas Specialist Wage Differential	(5,329)	3	1,776
Deferred Net Plant Due	(32,850)	3	10,950
Deferred Credits-2016 Regulatory Liability	(23,522)	3	7,841
Deferred Credits-2017 Regulatory Liability	(18,355)	3	6,118
Deferred Credits-2018. Regulatory Liability	(89,587)	3	29,862
Deferred Credits-2019 Regulatory Liability	(6,034)	3	2,011
Additional 2016 - 2018 NRAs	(88,115)	3	29,372
Total Deferred Credits	**$ (553,350)**		**$ 184,450**
OPEB Deferral	**$ (363,130)**	10	**$ 36,313**
Total Amortization Expense			***$ 220,763***

CORNING NATURAL GAS CORPORATION
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RATE YEAR DEPRECIATION EXPENSE

Account	Measuring and Regulating Station Structures	Staff Monthly Depreciation Rates	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22
	INTANGIBLE PLANT:													
301	Organization	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
302	Franchise and Consents	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-	-	-	-
	TRANSMISSION PLANT:													
	Land	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
365	Rights of Way	0.128%	69	69	69	69	69	69	69	69	69	69	69	69
366	Structures and Improvements	0.167%	86	86	86	86	86	86	86	86	86	86	86	86
367	Mains	0.119%	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616	4,616
369	Measuring and Regulating Station Equipment	0.185%	785	785	785	785	786	786	787	788	789	790	790	791
371	Other Equipment	0.208%	490	490	490	490	490	490	490	490	490	490	490	490
			6,046	6,046	6,047	6,047	6,047	6,048	6,049	6,050	6,050	6,051	6,052	6,052
	DISTRIBUTION PLANT:													
	Land	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
374	Land Rights	0.000%	-	-	-	-	-	-	-	-	-	-	-	-
375	Structures and Improvements	0.167%	330	330	330	330	330	330	330	330	330	330	330	330
376	Mains	0.128%	64,848	64,916	64,983	65,153	65,492	65,967	66,510	67,053	67,528	67,972	68,260	68,356
378	Measuring and Regulating Station Equipment	0.208%	8,494	8,525	8,556	8,633	8,788	9,004	9,251	9,498	9,715	9,876	9,959	9,986
380	Services	0.152%	28,675	28,697	28,719	28,775	28,885	29,040	29,217	29,394	29,549	29,672	29,739	29,762
381	excl. ERTS	0.278%	5,547	5,553	5,558	5,572	5,598	5,636	5,679	5,721	5,759	5,788	5,805	5,810
381.1	ERTS (Encoder, Receiver, Transmitter)	0.417%	1,225	1,231	1,237	1,252	1,282	1,324	1,372	1,420	1,462	1,495	1,513	1,520
382	Meter Installations	0.167%	4,656	4,656	4,656	4,656	4,656	4,656	4,656	4,656	4,656	4,656	4,656	4,656
383	House Regulators	0.185%	816	817	817	819	823	829	835	842	847	852	854	855
384	House Regulator Installations	0.185%	684	684	684	684	684	684	684	684	684	684	684	684
385	Industrial Meas and Reg Station Equipment	0.208%	311	311	311	311	311	311	311	311	311	311	311	311
			115,587	115,720	115,853	116,186	116,851	117,782	118,846	119,910	120,841	121,636	122,112	122,270
	GENERAL PLANT:													
389	Land and Land Rights		-	-	-	-	-	-	-	-	-	-	-	-
390	Structures and Improvements	0.177%	8,723	8,725	8,728	8,735	8,748	8,766	8,787	8,808	8,827	8,842	8,851	8,854
391	Office Furniture and Equipment	0.641%	20,451	20,493	20,534	20,637	20,844	21,133	21,463	21,794	22,083	22,236	22,272	22,283
392	Transportation Equipment	0.926%	12,168	12,226	12,283	12,427	12,714	13,117	13,577	14,037	14,439	14,792	15,008	15,081
393	Stores Equipment	0.333%	214	214	214	214	214	214	214	214	214	214	214	214
394	Tools, Shop and Garage Equipment	0.417%	5,079	5,090	5,100	5,128	5,182	5,257	5,344	5,430	5,506	5,564	5,594	5,604
395	Laboratory Equipment	0.333%	122	122	122	122	122	122	122	122	122	122	122	122
396	Power Operated Equipment	0.595%	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932
397	Communications Equipment	0.556%	813	813	813	813	813	813	813	813	813	813	813	813
			49,502	49,614	49,726	50,007	50,568	51,353	52,251	53,149	53,935	54,514	54,806	54,903
	Total		171,135	171,380	171,626	172,239	173,466	175,183	177,146	179,109	180,826	182,202	182,969	183,225
	Depreciation Expense Balance		(12,635)	(12,635)	(12,635)	(12,635)	(12,635)	(12,635)	(12,635)	(12,635)	(12,635)	(12,635)	(12,635)	(12,635)
	Depreciation of LPP at Applicable Rates		1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843	1,843
			160,343	160,588	160,834	161,447	162,673	164,391	166,354	168,316	170,034	171,409	172,177	172,433
	Annual Depreciation Expense	$ 1,990,998												

Appendix 5r

CORNING NATURAL GAS CORPORATION
CASE 20-G-0101

CAPITAL BUDGET BY PROJECT

Acct. No.	Project	Description	CY 2020	CY 2021	CY 2022	CY 2023	CY 2024
	1	**Services**					
380	1.1	New installations	$ 140,550	$ 143,361	$ 146,228	$ 149,153	$ 152,136
380	1.2	Systematic replacement	$ 612,848	$ 625,105	$ 637,607	$ 650,359	$ 663,366
380	1.3	Other replacement	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ 753,398**	**$ 768,466**	**$ 783,835**	**$ 799,512**	**$ 815,502**
	2	**Meters & Regulators**					
383	2.1	Residential regulators	$ 22,176	$ 22,620	$ 23,072	$ 24,004	$ 24,004
378	2.2	Non-residential regulators	$ 4,490	$ 4,580	$ 3,870	$ 4,765	$ 4,860
381	2.3	Residential meters	$ 61,500	$ 62,730	$ 63,985	$ 65,264	$ 66,570
381	2.4	Non-residential meters	$ 37,875	$ 38,633	$ 39,405	$ 40,193	$ 40,997
378	2.5	Rotary / turbine meters	$ 43,400	$ 37,944	$ 38,703	$ 39,477	$ 40,266
378	2.6	Volume correctors	$ 15,600	$ 15,912	$ 16,230	$ 16,555	$ 16,886
378	2.7	Pressure recorders	$ 3,720	$ 3,794	$ 3,870	$ 3,948	$ 4,027
378	2.8	AMR	$ 74,160	$ 75,643	$ 77,156	$ 78,699	$ 80,273
		Project Total	**$ 262,921**	**$ 261,856**	**$ 266,292**	**$ 272,905**	**$ 277,883**
	3	**Main - Distribution**					
376	3.1	New installations	$ -	$ 285,532	$ 291,242	$ 297,067	$ 303,008
376	3.2	Systematic Replacement	$ 1,546,787	$ 1,523,937	$ 1,097,234	$ 1,492,239	$ 1,617,214
376	3.3	Other replacement (Cross Town Line repair)	$ -	$ -	$ -	$ -	$ -
376	3.4	Other replacement (Leak Repair, system upgrades)	$ -	$ -	$ -	$ -	$ -
376	3.5	Blank	$ -	$ -	$ -	$ -	$ -
376	3.6	Blank	$ -	$ -	$ -	$ -	$ -
376	3.7	Blank	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ 1,546,787**	**$ 1,809,469**	**$ 1,388,476**	**$ 1,789,306**	**$ 1,920,222**
	4	**Main - HP Distribution**					
376	4.1	New installations	$ -	$ -	$ -	$ -	$ -
376	4.2	Line 11	$ -	$ -	$ -	$ -	$ -
376	4.3	Bath Reliability - Second Supply	$ 480,000	$ 306,000	$ 312,120	$ 318,363	$ 324,730
376	4.31	Line 15 Systematic Replacement	$ 600,000	$ 612,000	$ 2,184,840	$ 955,088	$ 649,459
376	4.4	Blank	$ -	$ -	$ -	$ -	$ -
376	4.5	Blank	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ 1,080,000**	**$ 918,000**	**$ 2,496,960**	**$ 1,273,450**	**$ 974,189**
	5	**Main - Distribution extension**					
376	5.1	Blank	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	6	**Cathodic Protection**					
376	6.1	System Cathodic Protection	$ 57,222	$ 58,366	$ 59,534	$ 60,724	$ 61,938
369	6.2	Blank	$ -	$ -	$ -	$ -	$ -
376	6.3	Blank	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ 57,222**	**$ 58,366**	**$ 59,534**	**$ 60,724**	**$ 61,938**
	7	**SCADA**					
391	7.1	Hardware / Software upgrade	$ -	$ -	$ -	$ -	$ -
378	7.2	RTU /other equipment (current installation improvements)	$ 46,818	$ 47,754	$ 48,709	$ 49,684	$ 50,677
		Project Total	**$ 46,818**	**$ 47,754**	**$ 48,709**	**$ 49,684**	**$ 50,677**
	8	**M&R Stations**					
378	8.1	M&R Station replacement	$ -	$ 94,889	$ 96,787	$ 98,724	$ 100,698
378	8.2	Herrington Station (odorizer install)	$ -	$ 500,000	$ 408,000	$ -	$ -
378	8.3	Orr Hill Station (odorizer install)	$ -	$ -	$ -	$ -	$ -
378	8.4	Blank	$ -	$ -	$ -	$ -	$ -
378	8.5	Blank	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ -**	**$ 594,889**	**$ 504,787**	**$ 98,724**	**$ 100,698**

CORNING NATURAL GAS CORPORATION
CASE 20-G-0101

CAPITAL BUDGET BY PROJECT

Acct. No.	Project	Description	CY 2020	CY 2021	CY 2022	CY 2023	CY 2024
	9	**Transportation Equipment**					
392	9.1	Replace small vehicle	$ -	$ 206,000	$ 210,120	$ 214,323	$ 163,957
392	9.2	Replace1987 Line Truck	$ 190,000	$ -	$ 200,000	$ -	$ -
392	9.3	Heavy Equip Trailer	$ -	$ -	$ -	$ -	$ -
392	9.4	Replace Backhoe	$ -	$ -	$ -	$ -	$ -
392	9.5	Purchase Mini Excav	$ -	$ 80,000	$ -	$ -	$ -
392	9.6	Replace small vehicle	$ -	$ -	$ -	$ -	$ -
392	9.7	Replace line tech truck	$ -	$ 40,800	$ -	$ -	$ -
392	9.8	Replace dump truck	$ -	$ -	$ -	$ -	$ -
392	9.9	Replace backhoe	$ -	$ -	$ -	$ -	$ -
392	9.10	Replace 1987 line truck	$ -	$ -	$ -	$ -	$ -
392	9.11	Heavy Equipment Trailer	$ -	$ -	$ -	$ -	$ -
392	9.12	Replace line truck	$ -	$ -	$ -	$ -	$ -
392	9.13	Replace 1996 line truck	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ 190,000**	**$ 326,800**	**$ 410,120**	**$ 214,323**	**$ 163,957**
	10	**Tools and Equipment**					
394	10.1	Pipeline Locator	$ 4,412	$ 4,500	$ 4,590	$ 4,682	$ 4,776
394	10.2	HFI	$ 12,000	$ -	$ -	$ -	$ -
394	10.3	CGI	$ 5,400	$ 5,508	$ 5,618	$ 5,731	$ 5,845
394	10.4	Portable Shoring	$ -	$ 10,200	$ -	$ -	$ 10,400
394	10.5	CP Data Logger	$ -	$ -	$ -	$ -	$ -
394	10.6	Blank	$ -	$ -	$ -	$ -	$ -
394	10.7	Electro fusion Controller	$ -	$ -	$ -	$ -	$ -
394	10.8	Mueller (8" to 12") machine	$ -	$ -	$ -	$ -	$ -
394	10.9	Health HFI	$ -	$ -	$ -	$ -	$ -
394	10.10	Engineering survey equipment	$ -	$ -	$ -	$ -	$ -
394	10.11	Blank	$ -	$ -	$ -	$ -	$ -
394	10.12	GPS Survey Equipment	$ -	$ -	$ -	$ -	$ -
394	10.13	Welding Machine	$ -	$ -	$ -	$ -	$ -
394	10.14	Blank	$ -	$ -	$ -	$ -	$ -
394	10.15	Blank	$ -	$ -	$ -	$ -	$ -
394	10.16	Lighting	$ -	$ -	$ -	$ -	$ -
394	10.17	Stopper Replacement Equipment	$ -	$ -	$ -	$ -	$ -
394	10.18	Misc.Tools and Equipment	$ 3,184	$ 3,247	$ 3,312	$ 3,378	$ 3,446
		Project Total	**$ 24,996**	**$ 23,455**	**$ 13,521**	**$ 13,791**	**$ 24,467**
	11	**Safety Equipment**					
394	11.1	PPE	$ 70,000	$ 71,400	$ 72,828	$ 74,285	$ 75,770
394	11.2	Flash fire coveralls / hood / gloves	$ 40,800	$ 41,616	$ 42,448	$ 43,297	$ 44,163
394	11.3	Supplied Air Respirator	$ -	$ -	$ -	$ -	$ -
394	11.4	Confined space gas monitor	$ 7,500	$ -	$ -	$ 7,950	$ -
		Project Total	**$ 118,300**	**$ 113,016**	**$ 115,276**	**$ 125,532**	**$ 119,933**
	12	**General Office**					
390	12.1	HVAC	$ -	$ -	$ -	$ -	$ -
390	12.2	Parking Lot Refurbishment	$ -	$ -	$ -	$ -	$ -
390	12.3	Office Furniture and Equipment	$ -	$ -	$ -	$ -	$ -
390	12.4	Building Upgrades	$ -	$ -	$ -	$ -	$ -
390	12.5	Work Stations	$ -	$ -	$ -	$ -	$ -
390	12.6	Roof	$ -	$ -	$ 90,000	$ -	$ -
390	12.7	Training Center	$ -	$ 78,000	$ -	$ -	$ -
		Project Total	**$ -**	**$ 78,000**	**$ 90,000**	**$ -**	**$ -**
	13	**IT equipment**					
391	13.1	Computers / software	$ 28,830	$ 29,402	$ 29,990	$ 30,590	$ 31,200
391	13.2	Field Laptops	$ 8,268	$ 4,216	$ 4,301	$ 4,386	$ 4,476
391	13.3	Field GPS equipment	$ 300,000	$ 100,000	$ -	$ -	$ -
391	13.4	CADD Software replacement	$ -	$ 100,000	$ -	$ -	$ -
391	13.5	Blank	$ 90,000	$ 5,000	$ 5,000	$ -	$ -
391	13.6	Printer and Computer Replacement	$ -	$ 3,000	$ -	$ -	$ -
391	13.7	Accounting and Billing System Upgrade	$ -	$ 15,000	$ -	$ -	$ -
391	13.8	Enterprise Software (Microsoft and Norton Updates)	$ -	$ 75,000	$ 50,000	$ -	$ -
391	13.9	AS400 Equipment/Software/Licensing Costs	$ -	$ 7,500	$ 7,500	$ -	$ -
		Project Total	**$ 427,098**	**$ 339,118**	**$ 96,791**	**$ 34,976**	**$ 35,676**
	14	**Major Projects**					
369	14.1	Virgil expansion - Main & Services	$ 10,000	$ 3,300	$ 3,366	$ 3,433	$ 3,502
380	14.2	Blank	$ -	$ -	$ -	$ -	$ -
383	14.3	Blank	$ -	$ -	$ -	$ -	$ -
378	14.4	Blank	$ -	$ -	$ -	$ -	$ -
369	14.6	Cross Town-E Pultney repair 2010	$ -	$ -	$ -	$ -	$ -
		Project Total	**$ 10,000**	**$ 3,300**	**$ 3,366**	**$ 3,433**	**$ 3,502**
						$ -	$ -
						$ -	**$ -**
		Total Budget	**$ 4,517,539**	**$ 5,342,489**	**$ 6,277,667**	**$ 4,736,359**	**$ 4,548,643**

CORNING NATURAL GAS CORPORATION
CASE 20-G-0101

RATE YEAR NET PLANT

	Rate Year Gross Plant Balance	CWIP Balance	Depreciation Reserve Balance
Jan-21 (1/2)	$ 48,151,334	$ 1,394,082	$ (15,129,567)
Feb-21	$ 96,405,610	$ 2,788,164	$ (30,434,244)
Mar-21	$ 96,508,551	$ 2,788,164	$ (30,609,601)
Apr-21	$ 96,611,492	$ 2,788,164	$ (30,785,203)
May-21	$ 97,023,257	$ 2,788,164	$ (30,961,418)
Jun-21	$ 97,640,904	$ 3,113,252	$ (31,138,860)
Jul-21	$ 98,464,434	$ 3,329,977	$ (31,318,019)
Aug-21	$ 99,287,963	$ 3,546,702	$ (31,499,141)
Sep-21	$ 100,111,493	$ 3,546,702	$ (31,682,226)
Oct-21	$ 100,729,140	$ 3,546,702	$ (31,867,029)
Nov-21	$ 101,332,908	$ 3,329,977	$ (32,053,206)
Dec-21	$ 101,453,661	$ 3,315,363	$ (32,240,152)
Jan-22 (1/2)	$ 50,787,207	$ 1,403,457	$ (16,213,677)
AVG OF THE MONTHLY AVG	$ 98,708,996	$ 3,139,906	$ (31,327,695)
NET PLANT	$ 70,521,206		

CORNING NATURAL GAS CORPORATION
CASE 20-G-0101

NET PLANT TRUE UP TEST

		RATE YEAR GROSS PLANT BALANCE	NIB CWIP BALANCE	DEPRECIATION RESERVE BALANCE	AVERAGE DEFERRED TAXES
		A	*B*	*C*	*D*
Jan-21	(1/2)	47,167,434	1,602,443	(15,129,567)	
Feb-21		94,421,920	3,204,885	(30,434,244)	
Mar-21		94,508,972	3,204,885	(30,609,601)	
Apr-21		92,086,342	3,204,885	(30,785,203)	
May-21		92,434,551	3,204,885	(30,961,418)	
Jun-21		92,956,865	3,204,885	(31,138,860)	
Jul-21		93,653,283	3,479,787	(31,318,019)	
Aug-21		94,349,701	3,663,055	(31,499,141)	
Sep-21		95,046,120	3,846,323	(31,682,226)	
Oct-21		95,582,080	3,846,323	(31,867,029)	
Nov-21		96,096,786	3,846,323	(32,053,206)	
Dec-21		96,199,727	3,677,455	(32,240,152)	
Jan-22	(1/2)	48,151,334	1,827,532	(16,213,677)	
AVG OF THE MONTHLY AVG		$ 94,387,926	$ 3,484,473	$ (31,327,695)	$ 5,135,789

NET PLANT TARGET PER ORDER	$ 124,064,305	*E = A + B - C - D*
EXAMPLE ACTUAL NET PLANT	$ 91,000,000	*F*
OVER/(UNDER)	$ (33,064,305)	*G = F - E*
Pre Tax Rate of Return	10.61%	*H*
Carrying Costs	$ (3,508,123)	*I = G * H*
Average Plant Balance	$ 94,387,926	*A*
Actual Depreciaton Expense	$ 986,284	*J*
Composite Depreciation Rate	1.045%	*K= J/A*
Delta Depreciation Expense	$ (345,497)	*L = G *K*
Total Carrying Costs	$ (3,853,620)	*M = I + L*

NOTE:
The Net Plant In Service includes all writedowns (e.g. Virgil Surcharge, Rootwell Surcharge, Service Adjustment), however these writedowns are not specifically identified in this Appendix.

Corning Natural Gas Corporation (Corning) Case 20-G-101 Gas Safety Metrics Appendix

Gas Safety Metric	Staff recommendation	CNG Counteroffer
Leak Management	- Reducing the number from five to four leaks at year end. - An NRA of ten basis points for failure to meet the repairable leak target, and five basis points for failure to meet the total leak backlog targets. - If the Company maintains less than 35 total leaks, but not less than 26 total leaks at calendar years-end, it would earn a PRA of two BPs. If the Company maintains less than 25 total leaks, but not less than 16 total leaks at calendar year's end, it would earn a PRA of four BPs. If the Company maintains 15 or less total leaks at calendar year's-end, it would earn a PRA of six BPs. If the Company maintains 15 or less total leaks at calendar year's-end, it would earn a PRA of eight BPs - The Commission should not provide a PRA for Type 3 leaks in its determination of the rate case.	- Corning proposes and Staff agrees to a more stringent target for total leak backlog, by reducing them from 50 to 45 leaks at year-end 2021.
Leak Prone Pipe Replacement	- Corning replace or eliminate a minimum of 10 miles of leak prone pipe (LPP) annually. - Corning replace a minimum of 250 leak prone services per year, concurrently with the main replacement program.	- Corning agrees with Staff's recommended target of ten miles of LPP per year but proposes that LPP include Lines 11 and 15.

Gas Safety Metric	Staff recommendation	CNG Counteroffer
	- All gas meters and service regulators be located outside on all new and replacement service installations. - Corning agrees that it will maintain records of the number of miles and feet of mains replaced, more specifically of the pipe replaced in the flood control area, and any incremental cost over the $33.96 cost per foot for systematic replacement of distribution main in calendar year 2021 utilized by the Staff Infrastructure and Operations Panel to calculate the average unit cost, but no more than 1.5 times cost per unit, be deferred. - The maximum NRA exposure increases to 15 BPs. Corning agrees with Staff's recommendation	- Corning agrees with Staff's recommendation that Corning replace 250 leak prone services per year in conjunction with main replacement. - Corning agrees with Staff's recommendation. Fourth, Staff recommends and Corning supports Staff's recommendation to allow Corning to address the leaks found in the flood control area through the leak prone pipe replacement program.
Damage Prevention	- The total damage target be set at a rate of 2.50 damage incidents per 1000 one call tickets; failure to achieve this target would result in an NRA of 20 BPs; for a rate between 2.26 and 2.50, the Company would incur an NRA of ten basis points; for a rate between 2.01 and 2.25, the Company would incur an NRA of five basis points; for a rate between 1.51 and 2.00, the Company would not incur or earn any revenue adjustments; for a rate between 1.26 and 1.50, the	- Corning proposes and Staff agrees that damages due to mismarks and damages due to Company or Corning Contractor targets be eliminated, and instead Corning should be allowed to maintain an overall damage target. - Corning counter-offered to Staff's

Gas Safety Metric	Staff recommendation	CNG Counteroffer
	Company would earn a PRA of five basis points; for a rate below 1.26 the Company would earn a PRA of ten basis points.	proposed maximum NRA exposure of twenty BPs by proposing a maximum NRA exposure of fifteen BPs, asserting that given the size of the company, a small change in the number of total damages would have a large impact on its overall damage performance.
Violations	- Recommends that of the $153,000 resulting from the negative revenue adjustments, $75,000 be used to fund the implementation of a Residential Methane Detector Program. - Modifying the current NRA BPs allocation by reducing the NRA BPs maximum exposure by 25 BPs, from 100 to 75 BPs per year for this measure. - Violation measure targets and associated NRAs be modified as follows: for record audits, the first five high risk violations would not subject the Company to NRAs; from the sixth to the 20th high-risk violations, the Company would incur one-half BP per violation; and for each high-risk violation greater than 20, the Company would incur one BP per violation. For the first 15 other risk violations, the Company would not	- Corning agrees and accepts Staff's recommendations regarding the violation measure targets and associated NRAs as stated in its testimony.

Gas Safety Metric	Staff recommendation	CNG Counteroffer
	be subject to a NRA; and for each other risk violation greater than 15, the Company would incur a NRA of one-fourth BP per violation. For field audits and investigations, the Company would incur a NRA of one-half BP for each of the first 20 high-risk violations; for each high-risk violation in excess of 20, the Company would incur a NRA of one BP per violation; and for all other risk violations, the Company would incur a NRA of one-fourth BP per violation. - For each audit year, capping the total record audit violation count at ten basis points for each of the code sections identified in Exhibit 44. - If the Company fails to comply with its implementation plan, the number of violations of a given code section that are in excess of ten would be included with the remainder of the violations being considered for the compliance measure. - The performance measure provide a financial disincentive for non-compliance with the pipeline safety regulations, but it addresses only the first ten record audit violations of a specific requirement. If the financial disincentive is insufficient to induce compliance, then additional measures are necessary to change the	

Gas Safety Metric	Staff recommendation	CNG Counteroffer
	performance. It is critical for the Commission to be able to address all violations of its pipeline safety regulations given the potential for serious harm.	
New York State Department of Environmental Conservation requirements and gas leaks found in Flood control area	- Corning be directed by the Commission to seek approval from DEC to perform the necessary work to repair or eliminate these leaks in the flood control area, and file quarterly updates with the Chief of Pipeline Safety and Reliability Section on the status of its work to eliminate or repair the leaks, along with copies of all DEC communications with the Company until all the leaks are eliminated.	- Corning agrees and states that leaks will be addressed through the leak prone pipe replacement program and they will continue to work with the DEC to complete the repairs. - Corning proposes to provide Staff a list of project(s) completed the prior year and those slated to be completed that year, the report will be submitted by January 10th of each year. Staff accepts.
The 1.1 miles of Pipe Located at Sullivan Park Science Center	- Corning perform the necessary operating and maintenance (O&M) work, such as: leak surveys, mark-outs, CP readings, corrosion control/monitoring, identification and inspection of below grade valves, etc. - Within 60 days from the date of Staff filing its direct testimony, the Company files with the Chief of Safety	- Corning states that Staff's recommendation to expect Corning to be able to assure the integrity of the 1.1 miles of pipe within matters of weeks is unrealistic, and that the Company proposes

Gas Safety Metric	Staff recommendation	CNG Counteroffer
	and Reliability Section a report outlining the O&M performed and the records obtained with an explanation of how the integrity of this pipe is guaranteed.	to file the requested report outlining the O&M performed and the records obtained by December 31, 2020.
Residential Methane Detector Program	- Commission direct Corning to develop and file a proposal, within 90 days from the issuance of its rate order, for a Residential Methane Detector pilot program. This proposal will include details on Corning's deployment strategies, the number of customers involved, the number of methane detector units, and the associated cost per unit.	
Training with First Responders and New York Pipeline Emergency Responders Initiative, or NYPERI	- Corning improves its existing training with fire departments and first responders by conducting emergency drills, hands-on activities, and workshops with a review of the processes and procedures that would be used during an emergency. To accommodate this training, we recommend that $78,000 be included in Corning's capital budget for the purpose of establishing a training center so that Corning can conduct fire drills, or for the acquisition of a trailer type vehicle equipped with the necessary equipment to conduct drills and simulate real-life or life like environmental conditions that	- Corning agrees with the necessity of this training and believes that it has an advantage in that its Training Technician is a Chief with a local volunteer department and is a Training Technician with the New York State Fire Training Academy.

Gas Safety Metric	Staff recommendation	CNG Counteroffer
	change similar to situations experienced in the field. - An incentive, a PRA of one BP for each drill conducted up to six BP per year, with the assumption that Department Gas Safety Staff will be invited to attend each drill and that documentation is provided following each drill including a video recording of each drill and a list of all persons taking part. - Implementing emergency drills which will help educate and train those individuals on how to respond prior to an incident. - Corning participates in the collaborative effort with the stakeholders (Natural Gas Local Distribution Companies, Fire Departments, State Fire Marshal, Department of Public Service, etc.) of the NYPERI.	
Monthly Leak Report	- Staff did not address this request in its direct testimony, however, it would not be opposed to the Company's request.	- Corning proposed in its direct and rebuttal testimony that it be allowed to discontinue submitting reports on a monthly basis regarding leak repair status, leak survey status, quantity of leaks discovered, quantity

Gas Safety Metric	Staff recommendation	CNG Counteroffer
		of leaks repaired, and quantity of main, pursuant to Commission order issued in case 05-G-1539.

Customer Service Performan Indicator (CSPI)		
Indicator Metric	**Calendar Year Metric Targets**	**NRA - Pre-Tax Basis Points**
Escalated Customer Complaints	3 or less	0
	4	5
	5	10
	6	15
Customer Satisfaction Survey	≥87.7%	0
	≥86.7% to <87.7%	5
	≥85.7% to <86.7%	10
	<85.7%	15
Appointments Kept	$25 Credit for Each Missed Appointment	

Customer complaints are not a rate, rather the acutal aggregate number of escalated complaints received in the calendar year.

Revenue Allocation
Rate Year Ending January 31, 2022

Incremental Revenue Adjustment	$ (765,664)
Contract Adjustment	$ 20,559
Revenue Tax Adjustment	$ 9,671
Merchant Function Charge	$ (92,274)
Adjustment Revenue Requirement	$ (827,708)
Percent On Base Rate	-5.00%

		Unitized ROR	Allocation Factor	Revenue at Current Rates	Based Revenue Increase	Adjustment	Total	% Increase	Revenue Target
	7.00%								
S.C. 1 & SC 14 Residential	5.84%	0.835	1.00	$ 11,918,904	$ (595,393)	$ (1,187)	$ (596,581)	-5%	$ 11,322,323
S.C. 3 & SC 14 Commercial	14.72%	2.103	1.00	$ 2,252,461	$ (112,519)	$ (224)	$ (112,743)	-5%	$ 2,139,718
S.C. 6 Commercial Transportation	4.51%	0.645	1.00	$ 678,674	$ (33,902)	$ (68)	$ (33,970)	-5%	$ 644,704
SC-7 Bath S.C. 1, 2 & 3 Transportation	11.57%	1.653	1.00	$ 1,554,565	$ (77,656)	$ (155)	$ (77,811)	-5%	$ 1,476,754
S.C. 8 Hamondsport Transportation	0.86%	0.123	0.80	$ 164,899	$ (6,590)	$ (13)	$ (6,603)	-4%	$ 158,296
Total				**$ 16,569,503**	**$ (826,061)**	**$ (1,647)**	**$ (827,708)**		**$ 15,741,795**

Delivery Revenue by Service Classification
Rate Year Ending January 31, 2022

			Rate Year Usage Ccf	Current Rates	Revenue @ Current Rates	Recommended Rat	Recommended Impact	Revenue @ Proposed Rates	% Increase	Revenue Impact	Revenue Targets
S.C. 1 & S.C. 14 Residential											
Customers			167,634	$ 19.75	$ 3,310,772	$ 19.75	$ -	$ 3,310,772	0%	$ -	
	First 3 Ccf		475,891								
	Next 47 Ccf	38.78%	5,359,007	$ 0.8274	$ 4,434,042	$ 0.7701	$ (0.0573)	$ 4,126,744	-7%	$ (307,298)	
	Over 50 Ccf	57.78%	7,984,105	$ 0.5228	$ 4,174,090	$ 0.4866	$ (0.0362)	$ 3,884,808	-7%	$ (289,283)	
			13,819,003		**$ 11,918,904**			**$ 11,322,323**		**$ (596,581)**	**$ 11,322,323**
S.C. 3 & S.C. 14 Commercial											
Customers			13,090	$ 30.25	$ 395,973	$ 30.25	$ -	$ 395,973	0%	$ -	
	First 3 Ccf		30,040						\		
	Next 47 Ccf	9.49%	385,525	$ 0.6902	$ 266,089	$ 0.6483	$ (0.0419)	$ 249,930	-6%	$ (16,159)	
	Over 50 Ccf	89.77%	3,646,867	$ 0.4361	$ 1,590,399	$ 0.4096	$ (0.0265)	$ 1,493,815	-6%	$ (96,584)	
			4,062,433		**$ 2,252,461**			**$ 2,139,718**		**$ (112,743)**	**$ 2,139,718**
S.C. 6 Commercial Transportation											
Customers			276	$ 120.00	$ 33,120	$ 120.00	$ -	$ 33,120	0%	$ -	
	First 3 Ccf		771								
	Over 3 Ccf	99.96%	2,168,471	$ 0.2977	$ 645,554	$ 0.2820	$ (0.0157)	$ 611,584	-5%	$ (33,970)	
			2,169,241		**$ 678,674**			**$ 644,704**		**$ (33,970)**	**$ 644,704**
S.C. 7 & Bath S.C. 1 2 & 3 Transportation											
Customers			122	$ 1,220.00	$ 148,840	$ 1,220.00	$ -	$ 148,840	0%	$ -	
	First 2500 Ccf		339,870								
	Over 2500 Ccf	97.00%	11,456,601	$ 0.1227	$ 1,405,725	$ 0.1159	$ (0.0068)	$ 1,327,914	-6%	$ (77,811)	
			11,811,471		**$ 1,554,565**			**$ 1,476,754**		**$ (77,811)**	**$ 1,476,754**
S.C. 8 Hammondsport Transportation											
Customers			91	$ 100.00	$ 9,100	$ 100.00	$ -	$ 9,100	0%	$ -	
	First 3 Ccf		267								
	Over 3 Ccf	99.96%	713,694	$ 0.2183	$ 155,799	$ 0.2090	$ (0.0093)	$ 149,196	-4%	$ (6,603)	
			713,961		**$ 164,899**			**$ 158,296**		**$ (6,603)**	**$ 158,296**
Total Firm Sales					**$ 16,569,503**			**$ 15,741,795**			
Corning Contracts											
	1		0		0			$ -			
	2		20,488,434		$ 633,868			$ 633,868			
	3		0		0		**Rate Increase Adjustment**	$ -			
	4		3,594,290		$ 446,178		$ 20,559.00	$ 425,619			
	5		281,136		$ 120,303			$ 120,303			
	6		1,574,280		$ 45,526			$ 45,526			
	7		3,906,244		$ 247,140			$ 247,140			
	8		0		0			$ -			
Total Contracts			29,844,384		**$ 1,493,014**			**$ 1,472,455**			
Total Sales		12,949,755 85,179,902	44,396,226 17,758,490		**$ 18,062,517**			**$ 17,214,250**			

Delivery Rates
Rate Year Ending January 31, 2022

	Current Rates		Rate Year Rates	
SC. 1 & 14 Residential				
Minimum Charge	$ 19.75	$	18.76	per month
First 3				
Next 47 CCF	$ 0.8274	$	0.7860	per Ccf
All Over 50 CCF	$ 0.5228	$	0.4966	per Ccf
S.C. 3 & 14 Commercial				
Minimum Charge	$ 30.25	$	28.74	per month
First 3 CCF				
Next 47 CCF	$ 0.6902	$	0.6557	per Ccf
All Over 50 CCF	$ 0.4361	$	0.4143	per Ccf
S.C. 6 Commercial Transportation				
Minimum	$ 120.00	$	113.99	per month
First 3 CCF				
All Over 3 CCF	$ 0.2977	$	0.2828	per Ccf
S.C. 7 & Bath S.C. 1, 2 & 3				
Minimum	$ 1,220.00	$	1,158.93	per month
First 2500 CCF				
All Over 2500 CCF	$ 0.1227	$	0.1166	per Ccf
S.C.8 Hammondsport Transportation				
Minimum	$ 100.00	$	96.00	per month
First 3 CCF				
All Over 3 CCF	$ 0.2183	$	0.2096	per Ccf

Note: Bath S.C. 2 and 3 is billed as one customer and assessed one minimum charge.

Corning Natural Gas Corporation
Rate Year Ending January 31, 2022

ANNUAL BILL IMPACTS

S.C. 1 Residential

Month	Sales Ccf	Bills at Presents Rates	Bills at Rate Year Rate	Difference Amount	Difference Percent
January	188	$ 196.92	$ 204.28	$ 7.36	3.7%
February	165	$ 176.59	$ 182.84	$ 6.25	3.5%
March	144	$ 158.60	$ 163.86	$ 5.26	3.3%
April	107	$ 125.76	$ 129.23	$ 3.47	2.8%
May	60	$ 84.76	$ 85.99	$ 1.23	1.4%
June	27	$ 48.65	$ 48.65	$ 0.00	0.0%
July	18	$ 38.97	$ 38.71	$ (0.27)	-0.7%
August	15	$ 35.05	$ 34.68	$ (0.37)	-1.1%
September	16	$ 36.28	$ 35.94	$ (0.34)	-0.9%
October	32	$ 54.86	$ 55.03	$ 0.17	0.3%
November	66	$ 90.32	$ 91.86	$ 1.53	1.7%
December	125	$ 141.95	$ 146.31	$ 4.35	3.1%
Annual Totals	**964**	**$ 1,188.72**	**$ 1,217.37**	**$ 28.65**	**2.4%**

	Present Rates	Rate Year Rates
First 3 Ccf	$ 19.75	$ 18.76
Next 47 Ccf	$ 0.82740	$ 0.78599
Over 50 Ccf	$ 0.52280	$ 0.49663
DRA	$ 0.00596	$ 0.00596
Federal Tax Act	$ (0.07260)	$ -
Merchant Function Charge	$ 0.01747	$ 0.01876
Gas Supply Charge	$ 0.39971	$ 0.39971

The Average Annual Usage is 964 Ccf.

S.C. 14 Residential Aggregation

Month	Sales Ccf	Bills at Present Rates	Bills at Rate Year Rates	Difference Amount	Difference Percent
January	265	$ 155.01	$ 164.01	$ 9.00	5.8%
February	214	$ 131.43	$ 138.38	$ 6.96	5.3%
March	195	$ 122.68	$ 128.88	$ 6.20	5.1%
April	146	$ 99.89	$ 104.11	$ 4.22	4.2%
May	83	$ 70.73	$ 72.42	$ 1.69	2.4%
June	41	$ 48.35	$ 48.49	$ 0.14	0.3%
July	29	$ 39.45	$ 39.30	$ (0.14)	-0.4%
August	23	$ 34.79	$ 34.49	$ (0.30)	-0.9%
September	25	$ 36.31	$ 36.07	$ (0.25)	-0.7%
October	46	$ 52.65	$ 52.94	$ 0.28	0.5%
November	97	$ 77.37	$ 79.63	$ 2.27	2.9%
December	177	$ 114.21	$ 119.67	$ 5.46	4.8%
Annual Totals	**1,339**	**$ 982.86**	**$ 1,018.41**	**$ 35.55**	**3.6%**

	Present Rates	Rate Year Rates
First 3 Ccf	$ 19.75	$ 18.76
Next 47 Ccf	$ 0.82740	$ 0.78599
Over 50 Ccf	$ 0.52280	$ 0.49663
DRA	$ 0.00596	$ 0.00596
Federal Tax Act	$ (0.06630)	$ -
Merchant Function Charge	$ -	$ -

The Average Annual Usage is 1,339 Ccf.

S.C. 3 Commercial

Month	Sales Ccf	Bills at Present Rates	Bills at Rate Year Rates	Difference Amount	Difference Percent
January	558	$ 492.38	$ 507.12	$ 14.74	3.0%
February	479	$ 428.50	$ 440.86	$ 12.36	2.9%
March	414	$ 375.26	$ 385.65	$ 10.38	2.8%
April	293	$ 277.59	$ 284.34	$ 6.75	2.4%
May	151	$ 163.09	$ 165.59	$ 2.50	1.5%
June	84	$ 109.00	$ 109.48	$ 0.49	0.4%
July	71	$ 98.21	$ 98.30	$ 0.08	0.1%
August	62	$ 91.34	$ 91.17	$ (0.17)	-0.2%
September	67	$ 94.83	$ 94.78	$ (0.04)	0.0%
October	96	$ 118.83	$ 119.68	$ 0.85	0.7%
November	184	$ 189.96	$ 193.46	$ 3.50	1.8%
December	**354**	**$ 327.47**	**$ 336.08**	**$ 8.61**	**2.6%**
Annual Totals	**2,814**	**$ 2,766.46**	**$ 2,826.50**	**$ 60.04**	**2.2%**

	Present Rates	Rate Year Rates
First 3 Ccf	$ 30.25	$ 28.74
Next 47 Ccf	$ 0.69020	$ 0.65565
Over 50 Ccf	$ 0.43610	$ 0.41427
DRA	$ 0.00596	$ 0.00596
Federal Tax Act	$ (0.05060)	$ -
Merchant Function Charge	$ 0.01747	$ 0.01876
Gas Supply Charge	0.39971	0.39971

The Average Annual Usage is 2,814 Ccf.

Corning Natural Gas Corporation
Rate Year Ending January 31, 2022

ANNUAL BILL IMPACTS

S.C. 6 Commercial Transportation

Month	Sales Ccf	Bills at Present Rates	Bills at Rate Year Rate	Difference Amount	Difference Percent
January	15,523	$ 10,688.29	$ 10,806.30	$ 118.01	1.1%
February	14,023	$ 9,666.61	$ 9,773.21	$ 106.60	1.1%
March	12,663	$ 8,741.09	$ 8,837.37	$ 96.27	1.1%
April	8,409	$ 5,844.44	$ 5,908.38	$ 63.94	1.1%
May	5,365	$ 3,772.28	$ 3,813.10	$ 40.82	1.1%
June	3,662	$ 2,612.38	$ 2,640.25	$ 27.87	1.1%
July	3,246	$ 2,329.00	$ 2,353.71	$ 24.71	1.1%
August	3,091	$ 2,223.74	$ 2,247.27	$ 23.53	1.1%
September	3,645	$ 2,600.69	$ 2,628.43	$ 27.74	1.1%
October	6,341	$ 4,436.31	$ 4,484.54	$ 48.23	1.1%
November	9,874	$ 6,842.16	$ 6,917.24	$ 75.08	1.1%
December	14,022	$ 9,666.47	$ 9,773.07	$ 106.60	1.1%
Annual Totals	**99,864**	**$ 69,423.45**	**$ 70,182.87**	**$ 759.42**	**1.1%**

	Present Rates	Rate Year Rates
First 3 Ccf	$ 120.00	$ 113.99
Over 3 Ccf	$ 0.29770	$ 0.28280
DRA	$ 0.00596	$ 0.00596
Federal Tax Act	$ (0.02250)	$ -
Merchant Function Charge	$ -	$ -
Gas Supply Charge	$ 0.39971	$ 0.39971

The Average Annual Usage is 99,864 Ccf.

S.C. 7 Industrial Transportation

Month	Sales Mcf	Bills at Present Rates	Bills at Rate Year Rates	Difference Amount	Difference Percent
January	13,256	$ 68,838.80	$ 69,384.11	$ 545.31	0.8%
February	11,193	$ 58,267.32	$ 58,720.64	$ 453.33	0.8%
March	11,200	$ 58,304.80	$ 58,758.45	$ 453.65	0.8%
April	7,846	$ 41,119.09	$ 41,423.21	$ 304.12	0.7%
May	7,664	$ 40,184.16	$ 40,480.15	$ 295.98	0.7%
June	7,477	$ 39,223.40	$ 39,511.02	$ 287.63	0.7%
July	7,470	$ 39,188.77	$ 39,476.10	$ 287.32	0.7%
August	7,838	$ 41,075.09	$ 41,378.83	$ 303.74	0.7%
September	7,302	$ 38,329.21	$ 38,609.06	$ 279.84	0.7%
October	7,247	$ 38,046.68	$ 38,324.07	$ 277.39	0.7%
November	10,551	$ 54,979.49	$ 55,404.21	$ 424.72	0.8%
December	11,166	$ 58,126.26	$ 58,578.36	$ 452.10	0.8%
Annual Totals	**110,210**	**$ 575,683.08**	**$ 580,048.20**	**$ 4,365.13**	**0.8%**

	Present Rates	Rate Year Rates
First 250 Mcf	$ 1,220.00	$ 1,158.93
Over 250 Mcf	$ 1.22700	$ 1.16558
DRA	$ 0.00596	$ 0.00596
Federal Tax Act	$ (0.10600)	$ -
Merchant Function Charge	$ -	$ -
Gas Supply Charge	$ 3.99712	$ 3.99712

The Average Annual Usage is 110,210 Mcf.

S.C. 8 Hammondsport Transportation

Month	Sales Ccf	Bills at Present Rates	Bills at Rate Year Rates	Difference Amount	Difference Percent
January	13,588	$ 8,317.12	$ 8,459.27	$ 142.14	1.7%
February	13,900	$ 8,505.58	$ 8,650.98	$ 145.40	1.7%
March	11,683	$ 7,164.59	$ 7,286.80	$ 122.21	1.7%
April	7,473	$ 4,618.91	$ 4,697.09	$ 78.19	1.7%
May	4,345	$ 2,726.96	$ 2,772.43	$ 45.47	1.7%
June	3,402	$ 2,156.50	$ 2,192.10	$ 35.60	1.7%
July	3,304	$ 2,097.66	$ 2,132.25	$ 34.58	1.6%
August	3,448	$ 2,184.75	$ 2,220.84	$ 36.09	1.7%
September	4,511	$ 2,827.61	$ 2,874.82	$ 47.21	1.7%
October	5,171	$ 3,226.74	$ 3,280.85	$ 54.11	1.7%
November	7,973	$ 4,920.91	$ 5,004.32	$ 83.41	1.7%
December	12,823	$ 7,854.25	$ 7,988.39	$ 134.14	1.7%
Annual Totals	**91,621**	**$ 56,601.59**	**$ 57,560.14**	**$ 958.55**	**1.7%**

	Present Rates	Rate Year Rates
First 3 Ccf	$ 100.00	$ 96.00
Over 3 Ccf	$ 0.21830	$ 0.20956
DRA	$ 0.00596	$ 0.00596
Federal Tax Act	$ (0.01920)	$ -
Merchant Function Charge	$ -	$ -
Gas Supply Charge	$ 0.39971	$ 0.39971

The Average Annual Usage is 91,621 Ccf.

Appendix 9

Corning Natural Gas Corporation
Rate Year Ending January 31, 2022

ANNUAL BILL IMPACTS

S.C 14 Commercial Aggregation

Month	Sales Ccf	Bills at Present Rates	Bills at Rate Year Rates	Difference Amount	Difference Percent
January	1,800	$ 765.64	$ 795.41	$ 29.77	3.9%
February	1,639	$ 700.56	$ 727.48	$ 26.91	3.8%
March	1,500	$ 644.63	$ 669.09	$ 24.46	3.8%
April	977	$ 434.24	$ 449.47	$ 15.22	3.5%
May	638	$ 297.68	$ 306.91	$ 9.23	3.1%
June	376	$ 192.20	$ 196.79	$ 4.60	2.4%
July	298	$ 160.92	$ 164.14	$ 3.22	2.0%
August	279	$ 153.22	$ 156.11	$ 2.89	1.9%
September	310	$ 165.58	$ 169.01	$ 3.43	2.1%
October	387	$ 196.79	$ 201.58	$ 4.80	2.4%
November	679	$ 314.25	$ 324.21	$ 9.95	3.2%
December	1,246	$ 542.32	$ 562.29	$ 19.97	3.7%
Annual Totals	**10,129**	**$ 4,568.05**	**$ 4,722.49**	**$ 154.44**	**3.4%**

The Average Annual Usage is 10,129 Ccf.

	Present Rates	Rate Year Rates
First 3 Ccf	$ 30.25	$ 28.74
Next 47 Ccf	$ 0.69020	$ 0.65565
Over 50 Ccf	$ 0.43610	$ 0.41427
DRA	$ 0.00596	$ 0.00596
Federal Tax Act	$ (0.03950)	$ -
Merchant Function Charge	$ -	$ -

Compression Surcharge Calculation

TCJA Surcredit Component

Service Classes	Four Months Sales *CCF	Total Annual Sales CCF	TCJA Rate (Per CCF)	TCJA Surcredits
S.C. 1 Residential	6,459,891	13,088,273	$ (0.0726)	$ (468,988)
S.C. 3 Commercial	1,117,822	2,345,495	$ (0.0506)	$ (56,562)
S.C. 6 Commercial Transportation	860,925	2,061,961	$ (0.0225)	$ (19,371)
S.C. 7 Industrial Transportation	2,653,272	7,859,634	$ (0.0106)	$ (28,125)
S.C. 8 Hammondsport Transportation	294,861	713,961	$ (0.0192)	$ (5,661)
S.C. 14 Residential Aggregate	349,916	730,730	$ (0.0663)	$ (23,199)
S.C. 14 Commercial Aggregate	835,072	1,716,938	$ (0.0395)	$ (32,985)
S.C. 1 Bath Firm	1,143,036	2,702,968	$ (0.0105)	$ (12,002)
S.C. 2 & 3 Bath Transportation	507,967	1,248,869	$ (0.0109)	$ (5,537)
Total	**14,222,762**	**32,468,829**		**$ (652,430)**

***CCF (January 31, 2021 through May 31, 2021)**

Base Rates Component

Base Rate Compression Surcharge %		**44.5%**
Revenue Requirement Decrease	$	(765,664)
Base Rate Compression Surcharge	**$**	**(340,929)**

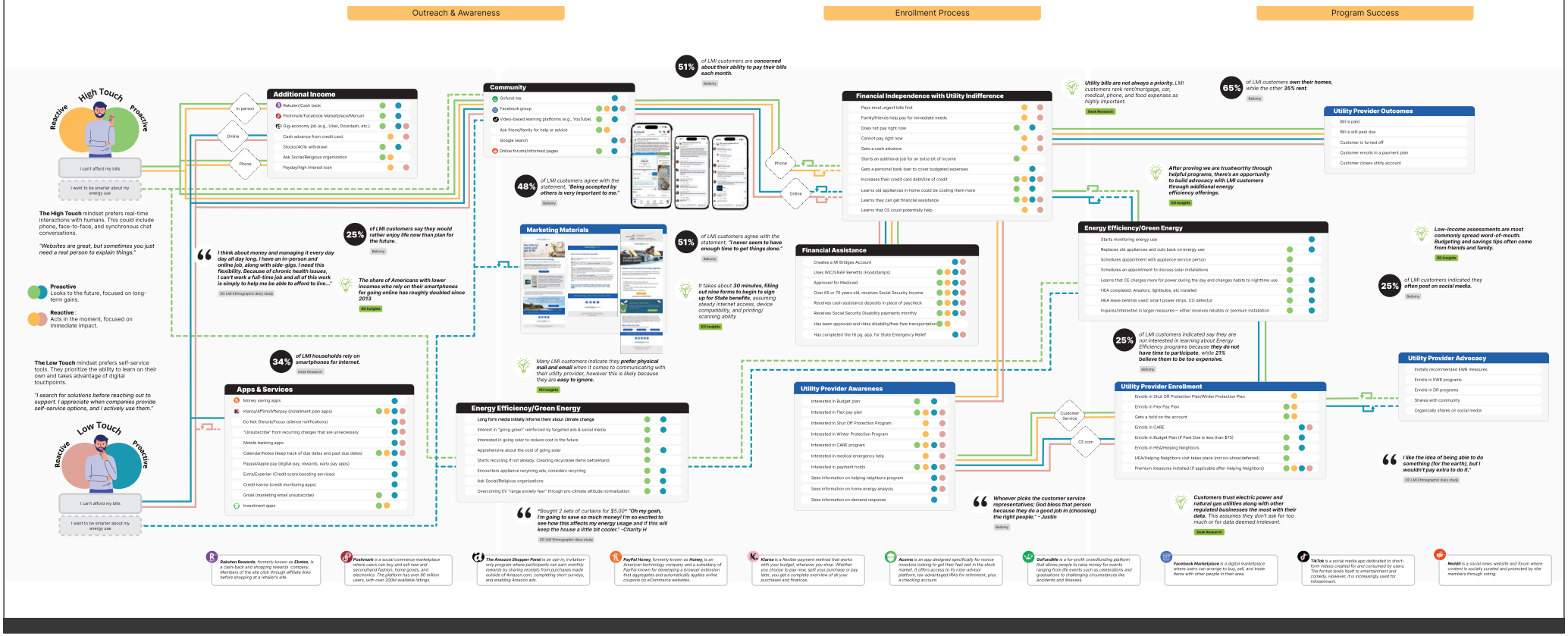
	Percent	Amount
Residential Allocation	72%	$ (245,469)
Non Residential Allocation	28%	$ (95,460)
TCJA Surcredit		$ 652,430
Total Compression Surcharge		**$ 311,501**

Revenue Decoupling Mechanism Target

RDM Residential Service Classes		
S.C. 1 & 14 Residential	$	11,322,323

LOW & MODERATE INCOME CUSTOMERS MINDSET MAP

CONSUMERS ENERGY EXPERIENCE DESIGN XD



Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company	Executive	Position	Base Salary	Target Annual Incentive ($)	Target Annual Incentive (%)	Target Total Cash Compensation [1]	Total Long-Term Incentive	Target Total Direct Compensation [2]
Alliant Energy Corporation	John O. Larsen	Chair, President & CEO	$1,025,000	$1,178,750	115%	$2,203,750	$3,776,810	$5,980,560
Ameren Corporation	Martin J. Lyons	President & CEO	$1,100,000	$1,210,000	110%	$2,310,000	$4,125,000	$6,435,000
Atmos Energy Corporation	John K. Akers	President & CEO	$920,000	$920,000	100%	$1,840,000	$2,957,744	$4,797,744
CenterPoint Energy, Inc.	David J. Lesar	Pres. & CEO	$1,475,000	$2,065,000	140%	$3,540,000	$8,481,250	$12,021,250
Consolidated Edison, Inc.	Timothy P. Cawley	COB, Pres., & CEO	$1,250,000	$1,562,500	125%	$2,812,500	$5,551,295	$8,363,795
DTE Energy Company	Gerardo Norcia	COB, Pres. & CEO	$1,276,923	$1,560,000	122%	$2,836,923	$6,524,979	$9,361,902
Edison International	Pedro J. Pizarro	Pres. & CEO, EIX	$1,330,000	$1,729,000	130%	$3,059,000	$7,647,587	$10,706,587
Entergy Corporation	Leo P. Denault	COB & CEO	$1,300,000	$1,820,000	140%	$3,120,000	$8,986,053	$12,106,053
Eversource Energy	Joseph R. Nolan, Jr.	Pres. & CEO	$1,200,000	$1,320,000	110%	$2,520,000	$5,624,000	$8,144,000
Hawaiian Electric Industries, Inc.	Constance H. Lau	Former HEI President & CEO	$955,000	$955,000	100%	$1,910,000	$3,204,098	$5,114,098
NiSource Inc.	Lloyd Yates	President & CEO	$1,000,000	$1,150,000	115%	$2,150,000	$4,500,000	$6,650,000
OGE Energy Corp.	S. Trauschke	Chair, President & CEO	$1,071,005	$1,178,114	110%	$2,249,119	$3,981,998	$6,231,117
Pinnacle West Capital	Jeffrey B. Guldner	COB, Pres. & CEO, PNW & APS	$1,100,000	$1,210,000	110%	$2,310,000	$4,079,762	$6,389,762
PPL Corporation	Vincent Sorgi	President & CEO	$1,133,000	$1,416,250	125%	$2,549,250	$5,111,866	$7,661,116
Public Service Enterprise Group	Ralph Izzo	President, Chair & CEO	$1,421,400	$1,989,960	140%	$3,411,360	$9,100,065	$12,511,425
Sempra Energy	Jeffrey W. Martin	Chair, CEO & President	$1,350,000	$2,025,000	150%	$3,375,000	$8,916,873	$12,291,873
WEC Energy Group, Inc.	Gale E. Klappa	COB	$1,083,600	$1,462,860	135%	$2,546,460	$3,204,333	$5,750,793
Xcel Energy Inc.	Bob Frenzel	COB, Pres. & CEO	$1,200,000	$1,500,000	125%	$2,700,000	$6,300,028	$9,000,028
n=18								
		Summary Statistics[3]						
		25th Percentile	$1,074,154	$1,186,563	110%	$2,264,339	$4,006,439	$6,270,778
		50th Percentile	$1,166,500	$1,439,555	124%	$2,547,855	$5,331,581	$7,902,558
		Average	$1,177,274	$1,458,469	122%	$2,635,742	$5,670,763	$8,306,506
		75th Percentile	$1,294,231	$1,687,375	134%	$3,003,481	$7,366,935	$10,370,416
CMS Energy	**Garrick Rochow**	**President & CEO**	**$1,150,000**	**$1,380,000**	**120%**	**$2,530,000**	**$5,200,000**	**$7,730,000**

Notes:
1. Target TCC (total cash compensation) includes base salary and target annual incentive.
2. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
3. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

Second Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company	**Executive**	**Position**	**Base Salary**	**Target Annual Incentive ($)**	**Target Annual Incentive (%)**	**Target Total Cash Compensation [1]**	**Total Long-Term Incentive**	**Target Total Direct Compensation [2]**
Alliant Energy Corporation	Robert J. Durian	EVP & CFO	$565,000	$423,750	75%	$988,750	$1,027,048	$2,015,798
Ameren Corporation	W.L. Baxter	Executive Chairman	$1,000,000	$1,000,000	100%	$2,000,000	$3,000,000	$5,000,000
Atmos Energy Corporation	Christopher T. Forsythe	SVP & CFO	$496,500	$322,725	65%	$819,225	$910,712	$1,729,937
CenterPoint Energy, Inc.	Jason P. Wells	EVP & CFO	$695,000	$521,250	75%	$1,216,250	$1,675,003	$2,891,253
Consolidated Edison, Inc.	Robert N. Hoglund	SVP & CFO	$838,400	$628,800	75%	$1,467,200	$1,608,575	$3,075,775
DTE Energy Company	David E. Meador	Former Vice Chairman & Chief Admin Officer	$789,231	$625,600	79%	$1,414,831	$1,895,147	$3,309,978
Edison International	Maria Rigatti	EVP & CFO, EIX	$710,000	$568,000	80%	$1,278,000	$1,775,086	$3,053,086
Entergy Corporation	Andrew S. Marsh	EVP & CFO	$710,700	$604,095	85%	$1,314,795	$2,008,880	$3,323,675
Eversource Energy	Werner J. Schweiger	EVP & COO	$770,001	$616,000	80%	$1,386,001	$1,748,151	$3,134,152
Hawaiian Electric Industries, Inc.	Ann C. Teranishi	ASB President & CEO	$790,617	$553,432	70%	$1,344,049	$766,898	$2,110,947
NiSource Inc.	Pablo A. Vegas	EVP, COO & President, NiSource Utilities	$618,000	$494,400	80%	$1,112,400	$1,235,000	$2,347,400
OGE Energy Corp.	B. Buckler	CFO	$440,000	$308,000	70%	$748,000	$755,200	$1,503,200
Pinnacle West Capital	James R. Hatfield	Former Advisor to CEO, PNW	$700,000	$525,000	75%	$1,225,000	$1,258,562	$2,483,562
PPL Corporation	Gregory N. Dudkin	EVP & COO	$740,000	$592,000	80%	$1,332,000	$1,595,363	$2,927,363
Public Service Enterprise Group	Ralph A. LaRossa	COO	$810,700	$729,630	90%	$1,540,330	$2,400,087	$3,940,417
Sempra Energy	Trevor I. Mihalik	EVP & CFO	$780,000	$702,000	90%	$1,482,000	$2,431,809	$3,913,809
WEC Energy Group, Inc.	J. Kevin Fletcher	Pres. & CEO	$1,087,934	$1,414,314	130%	$2,502,248	$3,241,666	$5,743,914
Xcel Energy Inc.	Timothy O'Connor	EVP & COO	$750,000	$637,500	85%	$1,387,500	$1,550,079	$2,937,579
n=18								
		Summary Statistics[3]						
		25th Percentile	$696,250	$522,188	75%	$1,218,438	$1,240,891	$2,381,441
		50th Percentile	$745,000	$598,048	80%	$1,338,024	$1,641,789	$2,995,333
		Average	$738,449	$625,916	82%	$1,364,366	$1,715,737	$3,080,103
		75th Percentile	$790,270	$635,325	85%	$1,454,108	$1,980,447	$3,320,251
CMS Energy	**Rejji Hayes**	**EVP & CFO**	**$775,000**	**$620,000**	**80%**	**$1,395,000**	**$1,700,000**	**$3,095,000**

Notes:

1. Target TCC (total cash compensation) includes base salary and target annual incentive.
2. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
3. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

Third Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company	Executive	Position	Base Salary	Target Annual Incentive ($)	Target Annual Incentive (%)	Target Total Cash Compensation [1]	Total Long-Term Incentive	Target Total Direct Compensation [2]
Alliant Energy Corporation	James H. Gallegos	EVP, GC & Corporate Secretary	$554,000	$360,100	65%	$914,100	$789,331	$1,703,431
Ameren Corporation	Michael L. Moehn	EVP & CFO	$715,000	$536,250	75%	$1,251,250	$2,298,567	$3,549,817
Atmos Energy Corporation	David J. Park	SVP, Utility Operations	$468,650	$281,190	60%	$749,840	$665,440	$1,415,280
CenterPoint Energy, Inc.	Scott E. Doyle	EVP, Utility Operations	$600,000	$450,000	75%	$1,050,000	$1,500,000	$2,550,000
Consolidated Edison, Inc.	Matthew Ketschke	Pres., Con Edison of New York	$646,000	$516,800	80%	$1,162,800	$1,608,575	$2,771,375
DTE Energy Company	Trevor F. Lauer	Pres. & COO - DTE Electric Company	$616,846	$496,800	81%	$1,113,646	$1,351,952	$2,465,598
Edison International	Steven D. Powell	Pres. & CEO, SCE	$650,000	$487,500	75%	$1,137,500	$1,527,600	$2,665,100
Entergy Corporation	Roderick K. West	Group Pres., Utility Operations	$753,819	$603,055	80%	$1,356,874	$1,840,794	$3,197,668
Eversource Energy	Philip J. Lembo	EVP & CFO	$720,001	$576,000	80%	$1,296,001	$1,634,650	$2,930,651
Hawaiian Electric Industries, Inc.	Gregory C. Hazelton	HEI EVP & CFO	$546,400	$355,160	65%	$901,560	$950,731	$1,852,291
NiSource Inc.	Donald E. Brown	EVP, CFO & President, Corporate Services	$618,000	$463,500	75%	$1,081,500	$1,200,000	$2,281,500
OGE Energy Corp.	W. Sultemeier	GC & Chief Compliance Officer	$460,000	$298,995	65%	$758,995	$694,817	$1,453,812
Pinnacle West Capital	Maria L. Lacal	EVP, Chief Nuclear Officer	$600,000	$450,000	75%	$1,050,000	$839,352	$1,889,352
PPL Corporation	Joseph P. Bergstein	EVP & CFO	$632,500	$506,000	80%	$1,138,500	$1,477,272	$2,615,772
Public Service Enterprise Group	Daniel J. Cregg	EVP & CFO	$714,300	$535,725	75%	$1,250,025	$1,750,045	$3,000,070
Sempra Energy	Kevin C. Sagara	EVP & Group President	$780,000	$702,000	90%	$1,482,000	$2,012,345	$3,494,345
WEC Energy Group, Inc.	Scott J. Lauber	Senior EVP & COO	$950,000	$807,500	85%	$1,757,500	$2,192,990	$3,950,490
Xcel Energy Inc.	Brian Van Abel	EVP & CFO	$650,000	$487,500	75%	$1,137,500	$1,550,036	$2,687,536
n=18								
		Summary Statistics[3]						
		25th Percentile	$600,000	$450,000	75%	$1,050,000	$1,013,048	$1,987,389
		50th Percentile	$639,250	$492,150	75%	$1,137,500	$1,513,800	$2,640,436
		Average	$648,640	$495,226	75%	$1,143,866	$1,438,028	$2,581,894
		75th Percentile	$714,825	$536,119	80%	$1,250,944	$1,721,196	$2,982,715
CMS Energy	**Shaun Johnson**	**SVP & General Counsel**	**$540,000**	**$405,000**	**75%**	**$945,000**	**$800,000**	**$1,745,000**

Notes:
1. Target TCC (total cash compensation) includes base salary and target annual incentive.
2. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
3. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

Fourth Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company	**Executive**	**Position**	**Base Salary**	**Target Annual Incentive ($)**	**Target Annual Incentive (%)**	**Target Total Cash Compensation [1]**	**Total Long-Term Incentive**	**Target Total Direct Compensation [2]**
Alliant Energy Corporation	David A. de Leon	SVP & President of WPL	$390,000	$195,000	50%	$585,000	$325,744	$910,744
Ameren Corporation	Richard J. Mark	Chairman & Pres., Ameren Illinois	$566,000	$396,200	70%	$962,200	$1,031,102	$1,993,302
Atmos Energy Corporation	Karen E. Hartsfield	SVP, GC & Corporate Secretary	$440,000	$264,000	60%	$704,000	$665,440	$1,369,440
CenterPoint Energy, Inc.	Monica Karuturi	EVP & GC; Former SVP	$580,000	$406,000	70%	$986,000	$1,102,000	$2,088,000
Consolidated Edison, Inc.	Deneen L. Donnley	SVP & GC	$630,400	$441,280	70%	$1,071,680	$903,540	$1,975,220
DTE Energy Company	David Ruud	SVP & CFO	$623,077	$441,000	71%	$1,064,077	$1,279,526	$2,343,603
Edison International	Adam S. Umanoff	EVP & GC, EIX	$605,000	$453,750	75%	$1,058,750	$1,331,021	$2,389,771
Entergy Corporation	Paul D. Hinnenkamp	EVP & COO	$649,877	$487,408	75%	$1,137,285	$1,923,508	$3,060,793
Eversource Energy	Gregory B. Butler	EVP & GC	$670,002	$469,000	70%	$1,139,002	$1,244,544	$2,383,546
Hawaiian Electric Industries, Inc.	Scott W. H. Seu	HE President & CEO	$506,667	$405,334	80%	$912,001	$821,385	$1,733,386
NiSource Inc.	Violet G. Sistovaris	EVP & Chief Experience Officer	$515,000	$386,250	75%	$901,250	$1,000,000	$1,901,250
OGE Energy Corp.	D.O. Jones	VP, Utility Operations	$355,000	$230,750	65%	$585,750	$412,809	$998,559
Pinnacle West Capital	Robert E. Smith	EVP, GC & Chief Development Officer	$610,000	$457,500	75%	$1,067,500	$762,436	$1,829,936
PPL Corporation	Paul W. Thompson	EVP, LG&E & KU Energy LLC (LKE)	$682,800	$580,380	85%	$1,263,180	$1,087,296	$2,350,476
Public Service Enterprise Group	Tamara L. Linde	EVP & GC	$657,800	$493,350	75%	$1,151,150	$1,300,019	$2,451,169
Sempra Energy	Karen L. Sedgwick	Chief Administrative Officer & Chief HR Officer	$460,000	$276,000	60%	$736,000	$736,000	$1,472,000
WEC Energy Group, Inc.	Xia Liu	EVP & CFO	$739,450	$591,560	80%	$1,331,010	$1,778,476	$3,109,486
Xcel Energy Inc.	Brett Carter	EVP, Group Pres., Utilities & CCO	$580,000	$464,000	80%	$1,044,000	$1,125,019	$2,169,019
n=18								
		Summary Statistics[3]						
		25th Percentile	$508,750	$388,738	70%	$903,938	$777,173	$1,757,523
		50th Percentile	$592,500	$441,140	73%	$1,051,375	$1,059,199	$2,040,651
		Average	$570,060	$413,265	71%	$983,324	$1,046,104	$2,029,428
		75th Percentile	$645,008	$467,750	75%	$1,120,884	$1,270,780	$2,375,278
CMS Energy	**Brian Rich**	**SVP & Chief Customer Officer**	**$495,000**	**$321,750**	**65%**	**$816,750**	**$850,000**	**$1,666,750**

Notes:

1. Target TCC (total cash compensation) includes base salary and target annual incentive.
2. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
3. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

Fifth Highest-Paid Officer Total Compensation Summary

			Total Compensation Opportunity					
Company	**Executive**	**Position**	**Base Salary**	**Target Annual Incentive ($)**	**Target Annual Incentive (%)**	**Target Total Cash Compensation [1]**	**Total Long-Term Incentive**	**Target Total Direct Compensation [2]**
Alliant Energy Corporation	Terry L. Kouba	SVP & President of IPL	$390,000	$195,000	50%	$585,000	$325,744	$910,744
Ameren Corporation	Fadi M. Diya	SVP & Chief Nuclear Officer, Ameren Missouri	$555,000	$360,750	65%	$915,750	$1,011,064	$1,926,814
Atmos Energy Corporation	J. Matt Robbins	SVP, HR	$332,072	$199,243	60%	$531,315	$665,440	$1,196,755
CenterPoint Energy, Inc.	Kenneth M. Mercado	Former EVP, Electric Utility	$525,000	$367,500	70%	$892,500	$997,500	$1,890,000
Consolidated Edison, Inc.	Robert Sanchez	Pres. & CEO, Orange & Rockland	$530,500	$424,400	80%	$954,900	$1,013,060	$1,967,960
DTE Energy Company	Mark W. Stiers	Pres. & COO - DTE Vantage and Energy Trading	$573,077	$403,900	70%	$976,977	$965,680	$1,942,657
Edison International	J. Andrew Murphy	SVP, Strategy & Corp Development, EIX	$475,000	$332,500	70%	$807,500	$712,515	$1,520,015
Entergy Corporation	Marcus V. Brown	EVP & GC	$710,700	$568,560	80%	$1,279,260	$1,507,328	$2,786,588
Eversource Energy	Christine M. Carmody	EVP HR & Info Technology	$541,001	$379,000	70%	$920,001	$1,005,122	$1,925,123
Hawaiian Electric Industries, Inc.	Kurt K. Murao	HEI EVP, GC Chief Admin Officer & Corporate Secretary	$402,000	$241,200	60%	$643,200	$499,262	$1,142,462
NiSource Inc.	Charles E. Shafer	SVP & Chief Safety Officer	$360,500	$216,300	60%	$576,800	$360,000	$936,800
OGE Energy Corp.	C. McQuistion	VP, Corporate Responsibility & Stewardship	$325,000	$146,250	45%	$471,250	$283,240	$754,490
Pinnacle West Capital	Theodore N. Geisler	SVP & CFO, PNW & APS	$450,000	$315,000	70%	$765,000	$1,051,582	$1,816,582
PPL Corporation	Wendy E. Stark	SVP, GC, Corporate Secretary & CLO	$525,000	$393,750	75%	$918,750	$647,968	$1,566,718
Public Service Enterprise Group	David M. Daly	Former Executive Advisor	$600,000	$450,000	75%	$1,050,000	$1,360,046	$2,410,046
Sempra Energy	Peter R. Wall	SVP, Controller & Chief Accounting Officer	$390,000	$195,000	50%	$585,000	$540,519	$1,125,519
WEC Energy Group, Inc.	Margaret C. Kelsey	EVP, GC & Corporate Secretary	$579,232	$434,424	75%	$1,013,656	$990,694	$2,004,350
Xcel Energy Inc.	Amanda Rome	EVP, Chief Legal & Compliance Officer	$570,000	$427,500	75%	$997,500	$1,050,034	$2,047,534
n=18								
		Summary Statistics[3]						
		25th Percentile	$393,000	$222,525	60%	$599,550	$567,381	$1,156,035
		50th Percentile	$525,000	$364,125	70%	$904,125	$978,187	$1,853,291
		Average	$490,782	$336,127	67%	$826,909	$832,600	$1,659,509
		75th Percentile	$566,250	$419,275	75%	$971,458	$1,012,561	$1,961,634
CMS Energy	**Brandon Hofmeister**	**SVP, Governmental, Regulatory & Public Affairs**	**$525,000**	**$341,250**	**65%**	**$866,250**	**$800,000**	**$1,666,250**

Notes:
1. Target TCC (total cash compensation) includes base salary and target annual incentive.
2. Target TDC (total direct compensation) = base salary + target annual incentive + long-term incentive.
3. Data are independently arrayed and thus will not sum to total cash/total direct compensation.

Question:

34. Refer to page 82 of the NGDP where it states, "Consumers Energy is assessing where hybrid heating and heat pump technology can best serve customers."
a. Please provide details about any assessment the Company has conducted to-date.
b. Please provide all analysis, resources, and references behind this statement, including any supporting data and workpapers with formulas intact and all sources, assumptions, and units clearly identified.
c. Please describe the Company's plans for deploying or supporting residential and commercial hybrid heating through 2030 and through 2050.
d. Is the Company analyzing any full electrification technologies (heat pump technology without natural gas back-up)?
i. If so, please provide this analysis. In answering this question, please also provide data on:
1. The switchover temperature at or below which a hybrid heating system (combining a heat pump with a backup gas heating system) would rely on the backup gas heating.
2. The associated efficiency value, expressed as the coefficient of performance (COP), for the hybrid heat pump at that switchover temperature.
e. If the Company is not analyzing full electrification technologies, please explain how the Company can assess the benefits of hybrid heating and heat pump technologies relative to full electrification technologies.

Response:

a. The Company has not yet assessed where hybrid heating and heat pump technology can best serve customers but has evaluated the impact of heat pump technology with Michigan residents served by non-regulated fuels. Please reference U21806-MNSC-CE-0039_Dreisig_ATT_1 for completed impact evaluation on heat pump pilot study.
b. Attachments U21806-MNSC-CE-0039_Dreisig_ATT_1, U21806-MNSC-CE-0039_Dreisig_ATT_2, U21806-MNSC-CE-0039_Dreisig_ATT_3 and Appendix C – Decarbonization Modeling of the Natural Gas Delivery Plan are the analyses performed to date on heat pump technology.
c. The Company does not have current plans to deploy or support hybrid heating through 2030 and 2050. Customer research will continuously monitor behavior and preferences to assess the future need to support hybrid heating and heat pump technology.
d. The Company is currently evaluating geothermal technology through thermal energy networks in local communities. Please reference attachment U21806-MNSC-CE-0039_Dreisig_ATT_4 showing the Company's network geothermal proposal to the MPSC.
    i. The Company has not determined the optimum switchover temperature yet for network geothermal technology.
    ii. A coefficient of performance (COP) value is not evaluated at this switchover temperature; however, industry research suggests that network geothermal technology provides the highest COP of any electrification technology. Attachment U21806-MNSC-CE-0039_Dreisig_ATT_5 compares network geothermal against other heat pump pathways clearly showing the highest COP amongst alternatives. This is important because it may provide the most mitigation to incremental peak electric load during winter months in a highly electrified future.

e. As noted, the Company's gas business at this time is investigating full electrification through network geothermal technology.

Witness: NEAL P. DREISIG
Date: February 3, 2025

U21806-MNSC-CE-0066
Page **1** of **1**

Question:

61. Refer to the following statement on page 82 of the Natural Gas Delivery Plan: "Modeling shows the most cost-effective means of electrifying residential end uses is with hybrid heating. Hybrid heating combines the heat content of natural gas with the efficiency of a heat pump. In this context, heat pumps would be used as much as possible; however, during the coldest winter months, natural gas furnaces would still be used to mitigate winter peak electric load. Consumers Energy is assessing where hybrid heating and heat pump technology can best serve customers."

a. Please provide the Company's analysis for this modeling in MS Excel workbook.

b. Please provide a detailed plan for the assessment of hybrid heating.

Response:

a. The Company does not have modeling completed for hybrid heating in Excel format. Analysis for electrifying residential end uses with hybrid heating is based on third party consultant modeling that sought to achieve the combination of technologies that provided the lowest societal cost.

   Confidential Attachment U21148-MNSC-CE-0066_CONF_ATT_1 shows the analysis that demonstrates the balanced combination of multiple technologies will all be needed to meet the State's 2050 net zero goal at the lowest cost. This attachment will be provided to parties that have executed a non-disclosure agreement under the protective order. This analysis is a State level analysis using proprietary data modeling through third party expert consultants. The Company does not own, have a copy of, nor have access to the modeling program used.

b. Hybrid heating is anticipated to have high carbon abatement costs compared to other technologies but can help mitigate the shift of electric peak demand to winter. This approach could reduce the need for $20-25B in capital investment for electric generation and transmission infrastructure making it an overall affordable solution without impacting the existing system. Customer research will continuously monitor behavior and preferences to assess future need for hybrid heating technology.

Witness: NEAL P. DREISIG
Date: January 30, 2025

U21806-MNSC-CE-0573
Page **1** of **1**

Question:

8. Refer to U21806-MNSC-CE-0039 Attachment 2, slides 11 through 13.

a. Please provide all sources and assumptions behind the Company's estimate for the cost of "New gas furnace + installation" and "New ASHP + installation".

b. Please explain what the figures "Preferred technology based on trends assumptions" show.

i. What do the numbers on these figures indicate?

ii. What are the assumptions behind the 'current trends' and 'accelerated trends' scenarios?

Response:

a. Heat pump analysis details on U21806-MNSC-CE-0039 Attachment 2, slides 11 through 13, are based on proprietary data modeling through third party expert consultants. The Company does not own, have a copy of, nor have access to the modeling program used. The Company used U21806-MNSC-CE-0573_ATT 1 and U21806-MNSC-CE-0573_ATT 2 to verify cost estimates and conclusions shown on U21806-MNSC-CE-0039 Attachment 2.

b.

i. Numbers on the figures reflect the most likely electrification technology to be adopted given a "business as usual" environment vs. an environment where accelerated decarbonization trends exist. Natural gas is overlaid to better understand directionally when specific electrification technologies make sense for customers. In all cases, the "business as usual" trend shows natural gas as the most affordable option for customers. U21806-MNSC-CE-0573_ATT 1 and U21806-MNSC-CE-0573_ATT 2 studies confirm this.

ii. Assumptions behind "current trends" include the current state of federal and state policy along with current cost estimates and efficiency factors for various electrification technologies. In this scenario, natural gas is the most affordable option for customers. Assumptions behind "accelerated trends" include scenarios where climate policy is pulled forward requiring the accelerated adoption of various technologies.

Witness: NEAL P. DREISIG
Date: March 18, 2025

U21806-MNSC-CE-0771
Page **1** of **1**

Question:

5. Refer to MNSC-CE-0571 where it states, "Cost of carbon abatement is assessed through a marginal cost of carbon abatement framework. This assessment is performed annually by primary pathway to understand cost effectiveness of reducing carbon as standalone technologies. External cost impacts are excluded from assessment. This analysis provides directional cost effectiveness by pathway to help prioritize decision-making."

a. Please provide all workpapers and analysis used to assess the marginal cost of carbon abatement for each standalone technology and pathway, in excel format with formulas intact and all units and assumptions clearly identified.

b. Please provide the workpapers and results of the latest "directional cost effectiveness" analysis including all calculations used in the analysis in excel format with formulas intact and all units and assumptions clearly identified.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that said request is not relevant to this proceeding. Consumers Energy is not requesting rate relief in this case related to carbon abatement in this proceeding. This request is outside the scope of the proceeding and does not appear to be reasonably calculated or necessary to gather any information that is important to the issues at stake in the case; thus, the request is not proportional to the needs of the case. S**ubject to the Company's objection and without waiving its objection, Consumers Energy responds as follows:**

a. Please find attached U21806-MNSC-CE-0771_ATT1, U21806-MNSC-CE-0771_ATT2, U21806-MNSC-CE-0771_ATT3, U21806-MNSC-CE-0771_ATT4.

b. Please find attached U21806-MNSC-CE-0771_ATT1.

Witness: NEAL P. DREISIG
Date: April 7, 2025

U21806-MNSC-CE-0039_ATT 1

Consumers Energy Count on Us®

CADMUS

2021 Cold-Climate Heat Pump Initiatives Evaluation Report

August 26, 2022

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Consumers Energy

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U21806-MNSC-CE-0039_ATT 1

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Acronyms and Abbreviations

Acronym	Definition
AC	Air conditioner
AMI	Advanced metering infrastructure
ASHP	Air-source heat pump
CCHP	Cold-climate heat pump
CDH	Cooling degree hour
COP	Coefficient of performance
HDH	Heating degree hour
HSPF	Heating seasonal performance factors
MEMD	*Michigan Energy Measures Database*
NPS	Net promoter score
PMOs	Property owners and managers
SEER	Seasonal energy efficiency ratio
TMY3	Typical meteorological year version 3

Executive Summary

In its March 5, 2020 Order Approving Settlement Agreement in Consumers Energy's *2020-2023 Energy Waste Reduction (EWR) Plan*, the Michigan Public Service Commission (MPSC) authorized the Company to invest in cold-climate heat pump (CCHP) initiatives for both income-qualified and non-income-qualified residential customers and business customers to test the efficacy, performance, and customer experience, among other factors. The Settlement Agreement[1] required the Company to submit an interim and final report delineating cold-climate heat pump (CCHP) initiative findings with the Company's 2020 and 2021 EWR Reconciliation filings, respectively. This report supplements the CCHP final report submitted as required by the March 5 Order and documents 2021 evaluation activities.[2]

The approved Settlement Agreement included both increased investment to support the income-qualified program performance metric associated with CCHP installations and a CCHP retrofit pilot initiative targeted to residential homes and businesses heated with electricity or heating fuels not regulated by the Michigan Public Service Commission, such as delivered propane or fuel oils. Given the challenges with implementing the CCHP initiatives, as well as unanticipated delays due to COVID-19, participation for income-qualified single-family and small commercial customers in 2021 occurred late in the year. This late participation has delayed the evaluation impact analysis for these two initiatives. All impact evaluation efforts will be completed in 2022 and the report will be filed in the case docket.

The main objective of these CCHP Initiatives was to demonstrate the potential for energy savings by replacing inefficient heating and cooling equipment with CCHPs. Consumers Energy targeted four distinct customer groups:

- Residential customers with electric or delivered fuel heating
- Income-qualified single-family customers with electric or delivered fuel heating
- Income-qualified multifamily customers with electric heating
- Small commercial customers with electric or delivered fuel heating

Consumers Energy designed its CCHP Initiatives to address both the supply and demand for CCHPs. The initiatives were implemented through Consumers Energy's existing residential, income qualified and small business product offerings. They aimed to strengthen trade allies' capabilities to install and service advanced heat pumps while increasing customers' awareness of and confidence in heat pumps as a viable, affordable, and environmentally friendly home heating source.

The CCHP Initiatives' incentives varied by customer type and ranged from $1,000 for market-rate customers to the full cost of installation for income-qualified and small business customers.

[1] Original settlement agreement: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000009hu1HAAQ at page 2
Settlement agreement amendment: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000CGUIcAAP

[2] Cadmus. 2020-2021 Cold-Climate Heat Pump Initiatives Final Report. May 18, 2022.

Consumers Energy marketed the initiatives through participating contractors, who were familiar with heat pump technology and had been educated about the offering, as well as through mass marketing campaigns and other Consumers Energy network partners like Habitat for Humanity. Table 1 through Table 3 shows participation and investments through December 31, 2021, by customer group and year.

Table 1. 2020 and 2021 Cold-Climate Heat Pump Participation and Investment

	Residential Market Rate	Income Qualified		Small Commercial	Total
		Single-Family	Multifamily		
2020 - 2021 Target	50 [a, b]	160	558	25 [b]	**793**
2020 - 2021 Installations	53	179	663	26 [c]	**921**
Percentage of Target	106%	112%	119%	88%	**116%**
Total Investment	$579,297	$3,184,143	$3,664,670	$999,000	**$8,427,110**

[a] The original Settlement Agreement targeted 100 heat pumps. Per the end of July 2020 reforecast; this was adjusted to 50 heat pumps.

[b] While the income qualified targets are specific to each year and summed in this table, the residential market rate and small commercial targets represent the total adjusted targets for the two-year period.

[c] This is updated from the 2020–2021 Cold Climate Heat Pump Initiatives Final Report.

Table 2. 2020 Cold-Climate Heat Pump Participation and Investment

	Residential Market Rate	Income Qualified		Small Commercial [a]	Total
		Single-Family	Multifamily		
2020 Target	100 [b]	100	225	25	**450**
2020 Installations	5	78 [c]	276	0	**359**
Percentage of Target	5%	78%	123%	0%	**80%**
2020 Investment	$258,771	$1,447,290	$1,523,558	$225,204	**$3,454,823**

[a] The small commercial initiative had eight commitments with three customers at the end of 2020, but no completed installations.

[b] The original Settlement Agreement targeted 100 heat pumps. Per the end of July reforecast, this was adjusted to 50 heat pumps.

[c] Of the 78 heat pumps, 74 were installed for a large group of duplexes owned by one landlord. Duplexes are classified as single-family homes.

Table 3. 2021 Cold-Climate Heat Pump Participation and Investment

	Residential Market Rate	Income Qualified		Small Commercial	Total
		Single-Family	Multifamily		
2021 Target	50	60	333	25	**468**
2021 Installations	48	101	387	26 [a]	**562**
Percentage of Target	96%	168%	116%	112%	**120%**
2021 Investment	$320,526	$1,736,853	$2,141,112	$773,796	**$4,972,287**

[a] This is updated from the 2020-2021 Cold-Climate Heat Pump Initiatives Final Report.

In addition to persistent market barriers to the adoption of CCHPs documented in the first-year summary of pilots, the Settlement Agreement imposed eligibility restrictions for Consumers Energy CCHP initiatives, requiring heat pump systems to displace at least 50% of a customer's heating load from delivered fuels or electric resistance heating systems and limiting residential eligibility to primary residences only (i.e. secondary or vacation homes were ineligible).

Consumers Energy continued to encounter several challenges with encouraging heat pump adoption across all income levels and all residential and multifamily building types. These challenges resulted in lower participation than expected and are attributed to a lack of consumer awareness, difficulty identifying eligible customers, lack of contractor participation, and, in some cases, high incremental costs. Consumers Energy encountered fewer challenges with small business owners given that the Initiative covered the full installation cost of the CCHP, but Consumers Energy recognizes this is not a sustainable program option and expects to encounter similar challenges as the residential market when the incentive no longer covers the full equipment and installation cost for customers.

Despite these challenges, participants were generally satisfied with their experience and gave high satisfaction ratings for the overall performance of their new heat pump. Participants also reported better working equipment and increased comfort compared to their previous equipment. In addition, the Evaluation team's impact analysis for market rate and income-qualified multifamily customers show most participants will save energy, and in turn, money on their heating and cooling bills; however, the ranges of savings vary based on the heating fuel type of the replaced equipment. An engineering analysis for income-qualified single-family customers and metering analysis for small commercial customers is currently underway and will be completed by end of 2022.

Consumers Energy contracted with independent teams led by Cadmus and TRC to evaluate its respective residential and commercial program portfolios (referred to jointly as the Evaluation team throughout this report). The Evaluation team focused on providing Consumers Energy with the necessary details to inform later phases of the CCHP Initiatives and on monitoring early performance in 2021 to comply with the evaluation and reporting requirements in its Settlement Agreement.

Research Objectives

The Cadmus team focused our evaluation on providing Consumers Energy with the necessary details to inform later phases of promoting CCHPs. Following discussions with Consumers Energy's program management staff, the Cadmus team identified several research objectives regarding the evaluation.

Cadmus assessed four research objectives:

Assess the CCHP Initiatives' performance according to energy savings, customer satisfaction, impacts to customer bills, operational issues, and customer comfort.

Understand market readiness to adopt heat pump technology on a large scale and learn about the challenges of installing CCHPs.

Determine current limitations in the CCHP supply chain and their potential implications for the CCHP Initiatives.

Understand how CCHPs impact low-income customers and property managers who own income-qualified housing on non-energy factors such as changes in energy bills, heating and cooling equipment operation, and comfort levels.

Research Approach

Starting in 2021, the Evaluation team conducted several research and evaluation activities:

- Interviews with Consumers Energy CCHP Initiatives managers and implementation contractors (n=7)
- Interviews with HVAC contractors, distributors, and CCHP manufacturers (n=18)
- Billing analysis, engineering reviews, site visits, and metering for commercial participants (n=9)
- Surveys or interviews with Initiative participants and property owners (n=51)
- Residential Market Rate Participant Engineering Analysis (n=51)
- Multifamily and Income Qualified Billing Analysis (n=77 participants and 112 comparison buildings)

Participation was limited across all initiatives. This meant there were small populations to survey, interview, and perform billing analysis activities even using the census of participants. Therefore, the generated results, in most cases, are not statistically significant and while the evaluation team has made some conclusions and recommendations in this report, there is remaining uncertainty about the technology performance and market potential of CCHPs in Michigan. In addition, participation for small business customers occurred later in 2021, which delayed the metering of small business CCHPs.[3] Results from this activity will be prepared for Consumers Energy in Q4 2022.

Report Organization

We organized this report as follows:

- Summary of Key Findings, Conclusions, and Recommendations
- Contractor, Distributor, and Manufacturer Findings
- Residential Market Rate Initiative Findings
- Income Qualified Multifamily Initiative Findings
- Commercial and Industrial Cold-Climate Heat Pump Pilot Findings
- Appendices
  - Appendix A: Survey and Interview Methodology and Details
  - Appendix B: Impact Analysis Methodology and Details
  - Appendix C: Consumers Energy Heat Pump Market Rate Customer Survey
  - Appendix D: Consumers Energy Heat Pump Property Owner and Manager Interview Guide
  - Appendix E: Consumers Energy Heat Pump Multifamily Tenant Survey Guide
  - Appendix F: Consumers Energy Heat Pump Commercial Interview Guide
  - Appendix G: Consumers Energy Heat Pump Contractor Interview Guide
  - Appendix H: Consumers Energy Heat Pump Manufacturer and Distributor Interview Guide

[3] Initial impact analysis for commercial customers is reported in " 2021 Cold Climate Heat Pump Pilot Impact Evaluation Results Memo submitted to Consumers Energy by TRC. Updated cooling savings will be provided at the conclusion of additional metering in November 2022.

Summary of Key Findings, Conclusions, and Recommendations

This section presents the Evaluation team's key research findings, conclusions, and recommendations associated with the four cold-climate heat pump (CCHP) research objectives, which informed our evaluation tasks. The remaining chapters of this report provide further explanation of these findings and support for our conclusions and recommendations.

Key Findings and Recommendations

CONCLUSION 1. There is low and varied awareness of cold-climate heat pumps by homeowners, property owners and their tenants, and commercial businesses and even lower awareness that Consumers Energy offers cold-climate heat pump rebates.

Participants' awareness of CCHPs and Consumers Energy rebates was largely driven by HVAC contractors and Consumers Energy. However, awareness varied among contractors and within the territories they served. Where contractors were aware of CCHPs, they were a driving force of information dissemination about heat pumps and Consumers Energy rebates for both residential and commercial customers.

TRADE ALLIES: Contractors' overall awareness of heat pump technologies was largely correlated with the heating fuels used by their customer base. Contractors serving rural populations (where delivered fuels are more common) were more familiar with ducted heat pump systems, while contractors serving urban populations (where electric resistance heating is more prevalent) were more familiar with ductless heat pump systems. Contractors indicated that Consumers Energy could be instrumental in driving awareness of heat pump technologies, citing the success of the campaigns used to promote smart thermostats.

MARKET RATE: Most Residential Market Rate pilot participants reported being familiar with CCHPs before deciding to purchase one for their home (eight of nine), but few (three of nine) were aware that Consumers Energy provided heat pump rebates. While CCHP rebates were new in 2020, respondents' awareness of heat pumps came primarily from contractors, with about half (five of nine) indicating that a contractor had recommended a heat pump before they learned about and applied for the Consumers Energy heat pump rebate. A small number of participants (two of nine) heard about the rebate through Consumers Energy email communications.

INCOME QUALIFIED MULTIFAMILY: Multifamily property owners and managers were generally aware (31%, or n=10 of 32) of CCHPs prior to being approached by Consumers Energy, though they were not aware of Consumers Energy incentives until their involvement. However, the property owners and managers' tenants reported a lack of knowledge regarding heat pumps, with 66% of tenant respondents (n=21 of 32) saying they did not know about CCHPs, and half saying they were not aware that there was a CCHP installed in their apartment at the time of the survey. Of the half that were aware of the heat pump installation, 56% (n=9 of 16) did not know that Consumers Energy was involved in the project.

COMMERCIAL: Only two out of seven interviewed commercial respondents were familiar with cold-climate heat pump technology prior to participation. Those who had heard of cold-climate heat

pumps were unaware of the advancements in technology that made heat pumps more feasible for regions, like Michigan, with very cold winters. After learning about the new cold-climate heat pumps and Consumers Energy's pilot, most respondents were motivated to participate, but still held reservations about performance during the winter, prompting some to ask to keep their old heating system as a back-up.

RECOMMENDATIONS

High Priority: Identify opportunities for Consumers Energy to promote the cold-climate heat pump technology and incentives. Consider providing materials, such as one-page initiative summaries, for distributors to leave with contractors during their interactions. Continue to promote cold-climate heat pumps through events like the Annual Trade Ally Kickoff or identify larger distribution events or trainings where Consumers Energy can interact with trade allies.

High Priority: Increase contractor and customer education of cold-climate heat pump benefits and technology. Consider increasing the promotion of cold-climate heat pumps through planned marketing campaigns (such as bill inserts and online advertising) and through cross-program promotions.

CONCLUSION 2. Because natural gas is the predominate heating fuel in Michigan, and current Michigan Public Service Commission policy limits fuel-switching, there are limited cost-effective cold-climate heat pump installation opportunities. This contrasts with other states such as Maine and Vermont where a higher percentage of homes use more costly heating fuels such as propane and oil and where state policies incentivize fuel-switching.

TRADE ALLIES: While demand is increasing, trade allies reported that multiple barriers have limited demand for CCHPs in Michigan compared to other states. Manufacturers and distributors noted that awareness of and affinity for CCHPs among contractors varied and some maintain the belief that heat pumps are not effective in cold climates. Contractors and distributors also reported that increased customer awareness would help increase adoption; however, the cost of new CCHPs remains prohibitive. A homeowner likely needs to financially benefit from switching to a CCHP to be interested, but the lifecycle cost of a new CCHP compared to alternative heating technologies supplied by natural gas (the predominate heating fuel in Michigan) likely does not financially benefit the homeowner at a time when natural gas rates are low. Contractors acknowledged this fuel-switching challenge and said that even when they identify a potential cold-climate heat pump customer, there are few tools available for the contractor or customer to make accurate projections of the total system lifetime cost savings.

MARKET RATE AND COMMERCIAL CUSTOMERS: During 2021 and 2022, the Michigan Public Service Commission allowed Consumers Energy to target market rate and commercial customers who receive non-regulated fuels and those with electric heating systems. Consumers Energy's *2018 Residential Appliance Saturation and Home Characteristics Study* found that approximately 82% of customers in single-family homes across Consumers Energy's natural gas, electric and combination fuel

service territory heat their homes with natural gas, while 4% use electric heat and 14% use another source such as propane, fuel oil, or wood. This heating fuel distribution creates a significant challenge with identifying homeowners and businesses that may be eligible for a CCHP under the current regulatory rules (i.e., heat their homes or buildings with electric or distributed fuels), and limits market potential. Of the residential market rate participants for which baseline analysis was conducted (n=51), the majority (59%) used propane or oil, while 31 % used electric heat and 10% used natural gas heat prior to installing their heat pump[4].

Four of the seven commercial respondents interviewed discussed wanting to move away from using propane, and two of the respondents were motivated to participate in the pilot specifically so they could stop using propane. While respondents appreciated the opportunity to move from propane to electric heating, it is unclear whether Consumers Energy can continue with this targeted approach beyond the pilot phase. Future negotiations between the Michigan Public Service Commission and Consumers Energy and its stakeholders will determine whether Consumers Energy can continue to rely on this targeted approach in future initiative cycles.

RECOMMENDATIONS

High Priority: Because contractors reported that it is not always simple to determine when cold-climate heat pumps are economically more beneficial than traditional equipment, provide them with sales tools, such as a cost-effectiveness calculator, that can assist them in identifying when a cold-climate heat pump makes financial sense for their customers.

Low Priority: Promote the space cooling benefits associated with a cold-climate heat pump. Cold-climate heat pumps are a good option to add cooling where there was not previously a whole-home space cooling system or where the cold-climate heat pump can replace inefficient central air conditioners and room air conditioners.

CONCLUSION 3. Participants were generally satisfied with their experience and gave very high ratings for the CCHP Initiatives offering. However, multifamily tenants' satisfaction was split, largely based on whether the tenant received education on how to operate the new equipment.

MARKET RATE: Market rate customers gave high satisfaction ratings, with all nine respondents giving a rating of 8 or higher for their overall experience with the heat pump. In addition, market rate customers were highly likely to recommend the heat pump to a friend (with a net promoter[5] score of +89).

[4] Consumers Energy excluded most customers that used natural gas for space heating from the CCHP initiative, but a small number of participants recruited by contractors used natural gas prior to installation of the CCHP.

[5] The net promoter score is expressed as an absolute number between -100 and +100 that represents the difference between the percentage of promoters (respondents giving a rating of 9 or 10) and the percentage of detractors (respondents giving a rating of 1 to 6).

INCOME QUALIFIED MULTIFAMILY: The three interviewed income qualified multifamily property owners and managers provided an average rating of 9.5 (on a 10-point scale) for their satisfaction with the CCHP Initiatives and their likelihood to recommend heat pumps to a colleague. The property owners and managers also rated their likelihood to adopt similar CCHP equipment in their other properties as a 9.0 on a 10-point scale.

Income-qualified multifamily tenants (n=23 of 32) were *very satisfied* with their CCHP experience, and generally felt that the heat pumps provided improved winter heating and summer cooling comfort. Multifamily tenant participants gave an average rating of 8.7 for their overall experience with the heat pump, though some may not have been aware of their heat pump until they were contacted for the survey. Respondents also gave an average rating of 8.8 regarding summer comfort and 7.9 regarding winter comfort. However, tenants' willingness to recommend Consumers Energy was dependent on the level of communication and instruction provided to them regarding equipment operation. Tenants who provided verbatim feedback around lack of instruction were more likely to provide a lower overall net promoter score (averaging +13) than those who received instructions (averaging +50). Similarly, tenants who reported that the installer did not set up their heating and cooling schedule were also more likely to provide a lower overall net promoter score (averaging +10) than those who had the installer set up a schedule (averaging +67).

COMMERCIAL: Commercial participants rated their overall satisfaction with the CCHP Initiatives as an average of 9.9 out of 10, and 86% (six out of seven interviewees) strongly agreed that Consumers Energy made it easy to participate in the initiative.[6] In follow up interviews with participants, four out of five interviewees reported being satisfied with their heat pump's performance during the winter.[7]

CONCLUSION 4. Some participants received a new thermostat with their CCHP. Participants who received a new thermostat had varied knowledge about how to use it to optimize operation of their heat pump and some could have benefitted from additional instructions and training.

MARKET RATE: Seven of the nine residential market rate participants had a programmable or smart thermostat, while two reported having a non-programmable thermostat. Of those who had a programmable thermostat, only two programmed temperature setbacks. Despite most having thermostat programming capability, four of nine tended to adjust the temperature manually.

INCOME QUALIFIED MULTIFAMILY: Only three income qualified multifamily respondents could confirm with certainty that the contractor set up a heating and cooling schedule for their heat pump. These three participants also confirmed that the heating and cooling schedule set up by the

[6] Commercial participants were interviewed prior to experiencing a full heating season and some respondents listed this uncertainty about how the equipment would perform during the heating season as a reason for not giving a higher satisfaction rating for their heat pump, though the average rating was still 9.3 out of 10.

[7] The one respondent who was displeased, noted that the heat pump took a while to turn on, they often felt a cool breeze that was discharged directly onto an employee, and they had to adjust their thermostat higher than usual in order to achieve their preferred temperature.

contractor was still in operation. Only 25% (n=8) reported receiving instructions or documentation about the heat pump or use of their thermostat with the heat pump.

COMMERCIAL: Most respondents needed additional time to learn how to use their new thermostats and a few had minor issues operating their heat pumps. While most respondents did not have any problems with their new heat pumps, some (43%; n=3) reported that learning how to use their new thermostat was the most challenging aspect of their new equipment. Two respondents (29%) also reported needing a contractor's assistance with minor issues related to operating their heat pump. These minor issues included resolving an installation error and adjusting the cooling so that the air temperature was reaching the thermostat's temperature setpoint. Another finding from the follow up interviews was that some customers needed additional support understanding the controls and settings of the heat pumps to maximize the value, especially when sites have overlapping building controls with multiple heating units.

RECOMMENDATION

High Priority: Consider increasing follow up communications and support after the installation to ensure participants understand their new technology. Sending follow-up emails with resources and providing high-touch support after the installation engenders a positive equipment experience, which is critical for word-of-mouth testimonial marketing. Encourage contractors to provide set up and programming instructions and provide contractor training to ensure they are familiar with different types of thermostats and systems.

CONCLUSION 5. Participants reported better working equipment and increased home and business comfort levels after the installation of their CCHP.

MARKET RATE: Most market rate participants surveyed (seven of nine) said their home was more comfortable after installing the heat pump. The nine respondents rated their comfort level as 9.1 on average during the summer, with a slightly lower rating of 8.6 (n=5) during the winter. None of the respondents indicated any concerns with the heat pump's ability to heat to a preferred comfort level. Five respondents also mentioned improved heating and cooling distribution across sections of the home.

INCOME QUALIFIED MULTIFAMILY: Income-qualified multifamily tenants said their homes were as comfortable with the CCHPs as before (43%), with one-quarter reporting increased comfort levels. A few tenants said their home was too hot or too cold after the heat pump installation. Property owners and managers indicated that tenant comfort was a key decision factor to install CCHPs.

COMMERCIAL: Customers were very satisfied with heat pump performance overall , though three interviewees (43%) reported some minor initial issues with their heat pumps, including one who said it did not cool down to the expected temperature and two who had issues with the installation that required a contractor to fix.

RECOMMENDATION

Medium Priority: Promote the increased home and business comfort that cold-climate heat pumps can provide during both the heating and cooling seasons. Developing and using home and business testimonials could be an effective way Consumers Energy can promote the benefits of cold-climate heat pumps such as increased comfort, lower energy bills, and for some, the addition of space cooling.

CONCLUSION 6: Distributors generally had heat pump inventory on hand, so delivery times were either not impacted or were only impacted temporarily by manufacturing delays.

While manufacturers and distributors reported manufacturing delays as a result of COVID-19, as well as on-going transportation delays, distributors generally reported having sufficient stock on hand to meet current demand. Only one distributor reported a delay (6 to 8 weeks) in getting equipment to the customer. Note that custom equipment was generally not discussed in the interviews with manufacturers and distributors, and it is possible that timelines for custom equipment could be different. It is also worth noting that the manufacturer and distributor interviews were conducted in April of 2021, and the factors influencing supply chains may have changed since this time.

CONCLUSION 7: Most residential market rate and income-qualified Multifamily participants realized heating and cooling utility bill savings after the installation of their CCHP. However, bill savings largely depends on heating fuel prior to the heat pump installation, as well as how the homeowner used their new equipment.

MARKET RATE: The majority of market rate participants replaced propane heating systems (51%), followed by electric heating (31%), natural gas heating (10%), and fuel oil heating (8%).[8] Based on engineering estimates, market rate participants who replaced propane or electric heating systems will realize approximately $910 to $1,680 in heating and cooling savings per year[9]. The five homes that previously heated with natural gas will likely see an increase in their utility bill of $450 per year on average due to the higher cost of electricity compared to natural gas; also, four of the five homes did not have existing central air conditioning, which means they will add electrical load in the summer.

INCOME QUALIFIED MULTIFAMILY: Income-qualified multifamily tenants, even though retaining their original baseboard heating systems, experienced annual savings of 896 kWh, which translates to approximately $147 in annual bill savings. Most of the savings (93%) were realized during the heating season (largely October-April). These savings during the heating season were equivalent to approximately 23% of baseline weather-sensitive electric heating use. Income qualified multifamily tenants experienced lower than anticipated savings attributable to the heat pumps because they continued use of their baseboard heating systems, consistent with other recent evaluation findings.

[8] At the time of conducting the engineering analysis the evaluation team had a sample of 51 CCHP installations.

[9] Based on fuel costs at the time of the analysis in January 2022.

INCOME QUALIFIED SINGLE FAMILY: Due to low participation and delays due to COVID, the Income Qualified Single-Family Impact analysis will be completed in 2022. The Evaluation team is currently conducting an engineering analysis of the impacts for the income-qualified single-family installations, relying on MEMD parameters and assumptions collected from customers such as home vintage, presence of central cooling, equipment efficiencies, tonnage, and other data. The analysis will be completed later in 2022 and filed in the case docket.

COMMERCIAL: Because participation in the small business pilot occurred later in 2021, the impact evaluation was delayed. The impact evaluation is based on metered data, and TRC is keeping the meters in place to collect data for at least one complete heating season and one complete cooling season for each site.[10] The results of the heating season impact analysis are presented in a separate memo that is included in the filing of 2021 studies made on August 31, 2022.[11] Metering for the 2022 cooling season is still in progress as of the writing of the report, and analysis will take place in later in 2022.

RECOMMENDATIONS

High Priority: Provide multifamily property owners who had cold-climate heat pumps installed with information for how continued use of baseboard heating systems will minimize the tenant's ability to achieve the highest potential heating, and cost savings.

High Priority: Provide multifamily property owners with handouts they can distribute to tenants with simple operational instructions to ensure all new tenants understand how to operate their heat pump systems. Additional follow up and coordination with maintenance staff to review proper operations would ensure persistence of heat pump savings.

High Priority: If the Michigan policy on fuel switching should change, natural gas heating customers should be screened prior to approval to ensure the heat pump has potential to reduce energy bills.

Table 4 shows the Evaluation team's conclusion for each research objective outlined above.

[10] Metering analysis was performed for 22 CCHP installations.

[11] TRC. 2022. C&I 2021 Cold Climate Heat Pump Pilot Impact Evaluation Memo

Table 4. Research Objective Mapping

Conclusion	Research Objective: 1. Assess Cold-Climate Heat Pump Initiative Performance	2. Understand Market Readiness and Challenges	3. Determine Current Supply Chain Limitations	4. Understand Impacts on Low-Income Customers
There is low and varied awareness of cold-climate heat pumps by homeowners, property owners and their tenants, and commercial businesses and even lower awareness that Consumers Energy offers cold-climate heat pump rebates.		✓		
Because natural gas is the predominate heating fuel in Michigan, and current Michigan Public Service Commission policy limits fuel-switching, there are limited cost-effective cold-climate heat pump installation opportunities. This contrasts with other states such as Maine and Vermont where a higher percentage of homes use more costly heating fuels such as propane and oil and where state policies incentivize fuel-switching.		✓		
Participants were generally satisfied with their experience and gave very high ratings for the Cold-Climate Heat Pump Initiatives offering. However, multifamily tenants' satisfaction was split, largely based on whether the tenant received education on how to operate the new equipment.	✓			✓
Some participants received a new thermostat with their cold-climate heat pump. Participants who received a new thermostat had varied knowledge about how to use it to optimize operation of their heat pump and some could have benefitted from additional instructions and training.		✓		
Participants reported better working equipment and increased home and business comfort levels after the installation of their cold-climate heat pump.	✓			✓
Distributors generally had heat pump inventory on hand, so delivery times were either not impacted or were only impacted temporarily by manufacturing delays.			✓	
Most residential participants realized heating and cooling utility bill savings after the installation of their cold-climate heat pump. However, bill savings largely depends on heating fuel prior to the heat pump installation, as well as how the homeowner used their new equipment.	✓			✓

Recommendation Priority

To assist Consumers Energy in prioritizing the actions needed to address these recommendations, the Evaluation team organized each evaluation recommendation by topic and prioritized them based on the following definitions.

- ***High Priority:*** The evaluation revealed compelling and conclusive data on a concern or a current initiative strength that are likely to have a significant impact on customer satisfaction, achievement of participation goals, or initiative savings if not addressed or maintained.
- ***Medium Priority:*** The evaluation revealed data that are inconclusive and require additional investigation or the issue is likely to have a moderate impact on initiative effectiveness or efficiency.
- **Low Priority:** The issue is likely to have little impact on initiative effectiveness or efficiency.

Table 5 lists the CCHP initiatives evaluation recommendations.

Table 5. Summary of Heat Pump Pilot Recommendations and Priorities

Priority	Summary of Recommendations
High Priority	Identify opportunities for Consumers Energy to promote the Cold-Climate Heat Pump technology and incentives. Consider providing materials, such as one-page initiative summaries, for distributors to leave with contractors during their interactions. Continue to promote cold-climate heat pumps through events like the Annual Trade Ally Kickoff or identify larger distribution events or trainings where Consumers Energy can interact with trade allies.
	Increase contractor and customer education of cold-climate heat pump benefits and technology. Consider increasing the promotion of cold-climate heat pumps through planned marketing campaigns (such as bill inserts and online advertising) and through cross-program promotions.
	Because contractors reported that it is not always simple to determine when cold-climate heat pumps are economically more beneficial than traditional equipment, provide them with sales tools, such as a cost-effectiveness calculator, that can assist them in identifying when a cold-climate heat pump makes financial sense for their customers.
	Consider increasing follow up and support after the installation to ensure participants understand their new technology. Sending follow-up emails with resources and providing high-touch support after the installation engenders a positive equipment experience, which is critical for word-of-mouth testimonial marketing. Encourage contractors to provide set up and programming instructions and provide contractor training to ensure they are familiar with different types of thermostats and systems.
	Provide multifamily property owners who had cold-climate heat pumps installed with information for how continued use of baseboard heating systems will minimize the tenant's ability to achieve the highest potential heating and cost savings.
	Provide multifamily property owners with handouts they can distribute to tenants with simple operational instructions to ensure all new tenants understand how to operate their heat pump heating systems. Additional follow up and coordination with maintenance staff to review proper operations would ensure persistence of heat pump savings.
	If the Michigan Public Service Commission policy on fuel switching should change, natural gas heating customers should be screened prior to approval to ensure the heat pump has potential to reduce energy use.
Medium Priority	Promote the increased home and business comfort that cold-climate heat pumps can provide during both the heating and cooling seasons. Developing and using home and business testimonials could be an effective way Consumers Energy can promote the benefits of cold-climate heat pumps such as increased comfort, lower energy bills, and for some the addition of space cooling.
Low Priority	Promote the space cooling benefits associated with a cold-climate heat pump. Cold-climate heat pumps are a good option to add cooling where there was not previously a whole-home space cooling system or where the cold-climate heat pump can replace inefficient central air and room air conditioners.

Contractor, Distributor, and Manufacturer Findings

Consumers Energy launched the CCHP initiatives just prior to the start of the COVID-19 pandemic, which as reported by Consumers Energy staff, created unique challenges such as long delays in project timelines due to back-ordered equipment. In addition, trade ally participation was low, with only one trade ally completing the vast majority of installations across these offerings in the early months of the initiative. To determine the sources of these barriers and understand the challenges associated with adopting CCHPs in Consumers Energy's service territory, the Evaluation team interviewed eleven contractors, two manufacturers, and five distributors involved in the installation, production, and distribution of CCHPs in Michigan.

Contractors' awareness and perceptions of CCHPs varied, and a contractor's interest in heat pump technologies in general depended largely on the availability of different heating fuels in their service territories. Contractors in rural areas, where delivered fuels are more common, had more awareness of and a greater affinity for ducted systems and heat pumps in general. Contractors in urban areas had more awareness of ductless systems, but overall lower levels of familiarity with and affinity for heat pump technologies.

Among all contractors, the pervading theme regarding CCHPs (and heat pumps in general) is that of uncertainty. In order to confidently promote heat pump technologies, contractors must be able to determine the operating cost of the equipment compared to a customer's existing equipment. Currently, there are no readily available tools that allow contractors to accurately model and compare the energy consumption of a heat pump to other heating sources; combined with the comparatively higher up-front cost of heat pumps, this inability to accurately model potential energy savings commonly makes heat pumps a non-starter. Furthermore, several contractors expressed a hesitancy to promote electric heating sources to their customers, as they perceived the price of electricity to be less static and more prone to price increases than other fuel sources. Additionally, some contractors were unaware that CCHPs were effective in cold climates. The confluence of uncertainty around CCHPs is commonly too significant of a barrier for contractors to abandon the status quo of a like-for-like equipment replacement.

Although there were manufacturing and transportation delays, distributors reported having stock on hand that was sufficient to meet current demand. Manufacturers and distributors noted that some contractors maintained the belief that heat pumps were not effective in cold climates (a finding that may be correlated with a contractor's location, given that the contractor interviews found that contractors in urban areas were less aware and less in favor of heat pumps compared to those in rural areas). Aside from this contractor barrier, manufacturers and distributors pointed to customer hesitation due to large up-front or long-term costs associated with CCHPs. In Michigan, CCHPs are less cost-effective than in other states due to the low cost of natural gas, but demand seems to be increasing, especially in rural areas where homes are predominantly heated with propane or oil.

This chapter provides contractor findings separately from manufacturer and distributor findings.

Contractor Findings

The Evaluation team interviewed eleven HVAC contractors to address three research objectives:

- Determine current awareness and perceptions of heat pump technologies.
- Identify the main barriers to installing heat pumps in Michigan.
- Identify marketing and outreach best practices.

The key findings corresponding to each research objective are outlined below.

Cold-Climate Heat Pump Awareness and Perceptions

Contractors' overall awareness of and attitudes toward CCHP technologies were largely correlated with the type of fuel available to the contractor's customer base. Contractors serving rural populations were more familiar with ducted systems, displayed an overall greater affinity for heat pump technologies, and reported higher levels of customer awareness and demand. Conversely, contractors serving urban populations were more familiar with ductless systems and displayed comparatively lower levels of familiarity with improvements in CCHP capabilities.

Contractors indicated that general awareness of heat pump technologies among customers was low but increasing. Contractors reported a marginal increase in the number of customers asking for the technology in recent months, and a more substantial increase in customers who were aware once the contractor presents CCHPs as an option. Similarly with contractor awareness, customer awareness is largely correlated with location and the availability of natural gas.

> "The typical customer is not aware it [CCHPs] is a heating option."
>
> - Contractor

Best Cold-Climate Heat Pump Applications

Contractors detailed the various scenarios in which CCHPs are currently being adopted by customers, or where they make the most sense for future adoption. For ducted systems, contractors reported the three best applications:

- Customers with propane or delivered fuels who have no access to natural gas
- Green-motivated customers who are not as cost conscious
- New construction

The best applications for ductless mini splits differ by heating versus cooling:

- Heating
  - Customers with electric baseboard heat—especially multifamily customers
  - Customers with hot or cold spots not served well by the existing system (and who could use heat pumps for supplementary heat)
- Cooling
  - Customers with no existing duct work (such as those with a boiler or electric baseboard heat)
  - Commercial applications, such as computer server rooms or elevator rooms
  - Vacation homes (that are not occupied in the winter)[12]

[12] Note that secondary or vacation homes were not eligible for the pilot.

Barriers to Adoption

Contractors provided a variety of reasons for the relatively slow adoption of heat pump technologies to date. Barriers primarily relate to financial constraints, either the up-front cost of the equipment or the comparatively higher operating cost (where natural gas is available). Adding to concerns over the operating cost is the idea that electric rates can be somewhat variable, so even if a contactor is able to project the operating cost of equipment for their customer, there is no guarantee that the projection will be accurate in the future. Furthermore, even when projecting operating costs using a fixed cost of electricity, there are no readily available tools by which contractors or customers can make accurate projections of the total system cost (equipment and operation). Several barriers were identified:

- Higher equipment cost versus other systems
- Relative higher cost of electricity compared to natural gas
- Variability in electric rates
- Inability to make accurate comparisons between the operating costs of CCHP systems to traditional heating systems
- Lack of education and awareness for the public and contractors alike
- Contractor perceptions of poor performance in the Michigan climate (less common)

Installation complexity and cost, supply chain robustness, and previous experiences with heat pumps are not seen as barriers among contractors. Contractors detailed how heat pumps generally require minimal additional work compared to traditional systems, and that relative to the additional cost of the equipment itself, the additional installation costs are negligible.

> "ASHPs [air-source heat pumps] have fallen off [become less common] for a couple reasons: most homes lately have a natural gas option, so we feel it is more to their advantage to use the gas furnace than air-to-air heat pumps."
>
> - Contractor

Overcoming Barriers to Adoption

There was no consensus among interviewed contractors as to what would be most influential in increasing CCHP adoption. Two contractors referenced a different rate structure for customers who use electric heat: Consumers Energy used to offer a special rate for customers with electric heat, and one contractor said the number of heat pumps they install has decreased since this rate was rescinded. These contractors believe that introducing an electric heating rate would potentially help to price CCHPs more similarly to natural gas–fired systems and lead to increased adoption:

- "If you choose a certain heating system, they used to offer a heating energy price decrease. If Consumers [Energy] could bring something like this back, demand would explode. Offer special rates for HP [heat pump] use for heating."
- "Used to do heat pumps more when they offered an electric heating rate, but we've switched to mostly natural gas due to cost of use."

Two contractors indicated that additional customer education is necessary to increase CCHP adoption, with one proposing a potential marketing campaign similar to the thermostat promotions that Consumers Energy currently offers. Other suggestions included offering increased rebates and a tool that helps customers more accurately project the lifetime operating costs of heat pumps against other space heating options:

- "Messaging would be a big bonus for all the contractors. It would help with promoting them [CCHPs]. Like the thermostat promotions that have produced a lot of positive feedback, [a campaign promoting heat pumps] would be very helpful."
- "Just educating people about that they've gotten the bugs out of these things [CCHPs] and they're working great."
- "Better rebates on them [CCHPs] for sure. With the [heat pumps] we have had a hard time meeting Consumers Energy's rebate requirements to qualify; our basic ASHP [air-source heat pump] doesn't qualify [and would] need to get up into the second or third level of efficiency, and with the increased cost the low [$100] rebates are not effective."
- "[It would be great] if Consumers [Energy] were able to come up with a tool comparing purchase and operational costs of electricity versus natural gas systems, showing savings of switching over when customers have dual fuel systems."

Marketing and Outreach Suggestions

As previously noted, two contractors said that increased customer education would be the most impactful way to increase customer demand for CCHP technologies. Each interviewed contractor suggested specific comparisons or promotional strategies to present the equipment to customers:

- Two suggested direct promotional campaigns from Mitsubishi that have been successful within Michigan
- One suggested using smart thermostat promotions from Consumers Energy
- One suggested promoting heat pumps as an air conditioner (AC) that also provides free heat
- One suggested offering a winter electric heating rate for owners with a CCHP
- One suggested providing tools to demonstrate savings compared to other systems

Income-Qualified Considerations

Two contractors indicated that unique circumstances may prevent the widespread adoption of heat pumps for income-qualified customers:

- The potential for theft of the costly units
- Low-income property managers' aversion to potential equipment issues and ensuing repairs

Distributor and Manufacturer Findings

The Evaluation team interviewed five distributors and two manufacturers of CCHPs in Michigan to address several research objectives:

- Confirm and document the supply chain for CCHPs in Michigan
- Identify the barriers leading to extended timelines for CCHP installation
- Identify sources of differences in CCHP installation costs across states
- Explore the cause of low participation by trade allies
- Identify any additional barriers and challenges delaying the widespread adoption of CCHPs in Michigan, like training or education
- Identify ways in which Consumers Energy can influence market adoption

The key findings corresponding to each research objective are outlined below.

Cold-Climate Heat Pump Supply Chain

Manufacturers and distributors confirmed that CCHPs follow a traditional supply chain structure, with no difference compared to traditional air-source heat pumps (ASHPs) or other types of HVAC equipment. While this typically means that units move from the manufacturer to the distributor and then to a contractor before reaching customers, there are exceptions for national corporate customers, who may purchase equipment directly from a distributor rather than through a contractor (see Figure 1).

Many CCHPs are manufactured abroad and shipped to ports in the United States, primarily to California or Georgia, before being trucked to regional destinations.

Figure 1. Heat Pump Supply Chain

Installation Timelines

Distributors reported it takes from one to 20 weeks to receive inventory from manufacturers, depending on whether the manufacturer is overseas or domestic and whether they placed a rush order. Manufacturers and distributors reported experiencing manufacturing delays as a result of COVID-19, as

well as ongoing transportation delays that included backups at ports and a truck driver shortage that began in 2018, prior to the pandemic.

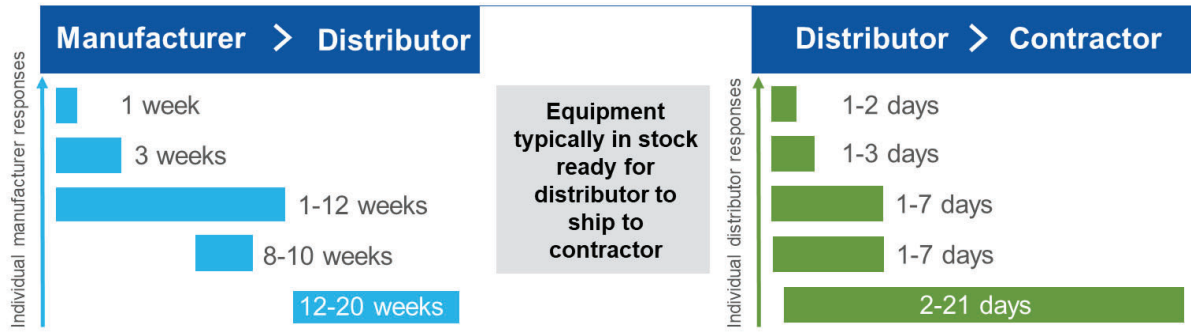
Despite manufacturing and transportation delays, distributors generally reported having stock on hand, so installation times were either not impacted or were only impacted temporarily. For the most part, distributors had learned how to manage around these constraints by being proactive and front-loading inventory. With enough inventory in stock, they can prevent delivery delays from impacting installation timelines:

- "With COVID-19, a lot of the supply chains have been broken. We were very responsive and proactive this year by buying up huge amounts of inventory. If we were to stop purchasing equipment now (March 2021), we would have enough equipment to last through November." – Distributor
- "This whole COVID thing really threw a wrench in a lot of this, and so I think a lot of it, the success that we have seen, having a little bit of inventory in Michigan, has to be to the credit of the distributor being proactive." – Manufacturer

When distributors have stock on hand, they reported that they typically deliver equipment to the contractor within one week, as shown in Figure 2. For a custom system or for equipment not in stock, the delivery timeline can stretch to three weeks or more, and one distributor had seen delays reach as long as six to eight weeks at points earlier in the pandemic, saying, "Much like everything else in the world, COVID really wreaked some havoc on manufacturing, so you know there were some times when it was six to eight weeks, but thankfully with good planning, we had enough stock that we really didn't have to deal too much with it [delays]." One distributor stated that custom equipment requires roughly 30 days to get to the contractor. Note that with the exception of this one distributor, timelines for custom equipment were not discussed in the interviews. It is possible that timelines for custom equipment could be different.

Notably, manufacturers and distributors have not observed any issues with the supply chain or with installation timelines that are unique to CCHPs or to Michigan.

Figure 2. Equipment Delivery Timelines Reported by Distributors



Note: The range in times for equipment to be delivered from the manufacturer to the distributor is due to differences between oversees versus land shipping and rush versus standard orders. One distributor also noted that COVID-19 led to six- to eight-week delays in equipment getting from the distributor to the contractor.

Cold-Climate Heat Pump Cost Differences across States

Most interviewed distributors and manufacturers did **not** report CCHP cost differences between Michigan and other states. One exception was a distributor who reported that installation costs in Michigan are higher compared to the Northeast. The distributor linked this difference to lower familiarity among installers in Michigan and said they expect costs to go down as installers become more familiar with the technology.

Within Michigan, interviewees observed differences in cost based on location in the state, with labor costs in urban areas being higher than costs in more rural areas. As one distributor stated, "Michigan prices are pretty average compared to Ohio [prices]. If you're in a more rural area, installation prices tend to go down, and if you're in a bigger, more metropolitan area then prices tend to go up."

One manufacturer also pointed out cost differences depending on whether contractors are union or non-union: "We go from $85 an hour that a contractor will charge a consumer to $140, especially if they are [in] a union. Or [when] you get into the Motor City, they seem to think they can charge a lot more."

Four of the five distributors reported increased CCHP costs over the last six months, and two interviewees noted that the cost of materials is rising—particularly for sheet metal, steel, and copper—which could lead to further cost increases down the road. As one distributor said, "[Internal costs] are going through the roof, [and] manufacturers can't eat it all."

Contractor Engagement

All five of the interviewed distributors shared the perception that there are still contractors in Michigan who do not have a full understanding of CCHPs and need to become more familiar with the technology and benefits. All five distributors also reported offering trainings to contractors to further their knowledge of CCHPs, including installation and service trainings as well as sales-oriented trainings: "We do training at every level possible, from technical service/installation to sales, and we have even offered business training."

Reports of attendance at trainings varied, with three who said their trainings were well-attended, one who said there was a mix of well-attended and less well-attended trainings, and another who said they were not well-attended, which they attributed to a lack of awareness of CCHP technology. One distributor also reported that, in their experience, one-on-one trainings work better than trainings offered in a group setting. Many training offerings have been moved to virtual platforms like Zoom due to the pandemic, which two distributors noted has been more challenging than in-person trainings.

Interviewees noted that trainings do not differ by state, e.g., they do not address specific climate, available programs, or current policies.

Barriers to Adoption

Four distributors mentioned that one barrier to CCHPs becoming more common in Michigan is that awareness of and trust in CCHP technology is not yet widespread among contractors in the state.

Instead, they reported that many contractors continue to hold an outdated perception that heat pumps are not a viable option in cold climates:

- "A lot of the contractors, especially a lot of the old timers... They don't see heat pumps as a viable option in Michigan. We hear that so many times." – Distributor
- "As technology continues to get better and heat pumps can operate at lower temperatures, you're always going to have an old service tech or installer that absolutely does not believe in the new technology." – Distributor
- "A lot of contractors are not as informed as they could be." – Distributor

Other barriers mentioned include concerns about up-front and long-term costs and, relatedly, the lack of incentives (since current policies in Michigan do not allow utilities to incentivize customers to switch from natural gas heat to electric heat).

Interviewees reported that demand for CCHPs is higher in other states than in Michigan. One attributed this lower demand in Michigan to the lack of widespread understanding among contractors and customers that heat pumps can be effective in cold climates. Others discussed the trade-offs in switching from different fuel sources. One distributor pointed out that natural gas is cheaper in Michigan than in other states, making CCHPs less cost-effective, and therefore less appealing, for those who currently use natural gas heating.[13] For those who use more expensive propane or fuel oil systems, however, distributors felt switching to a heat pump *would* be more cost-effective: "All-electric heat is a no-brainer. If they have propane or fuel oil, [heat pumps] make sense. With a natural gas system, it is a tougher sell."

Overcoming Barriers

Although interviewees reported that demand for heat pumps is lower in Michigan than elsewhere, they have also observed that demand in the state is increasing. Two distributors reported seeing major growth in CCHP adoption in recent years: one reported that their 2021 quarter 1 CCHP sales were greater than CCHP sales in the previous two years combined, and another reported having record demand in 2020, with sales doubling from 2019.

> "Ductless mini-splits are a huge, growing market, [with] the largest growth potential of any [technology], and everyone is saying the same thing."
>
> - Distributor

While there are still awareness and education gaps, interviewees reported that contractors and customers are becoming increasingly familiar as CCHPs have become more technically viable. As mentioned above, CCHPs are also increasingly *economically* viable in rural areas where there is a reliance on propane and oil heat.

[13] The proportion of households in Michigan with natural gas heating (82%) is higher than in most other states (Consumers Energy. 2018 Residential Saturation Study. Not available online).

The two biggest tools that interviewees noted as key to increasing CCHP adoption are incentives and increasing contractor and customer education. Several distributors emphasized that incentives and rebates are highly appealing to customers, making them an important tool for increasing adoption:

- "Customers would be willing to switch with an incentive." – Distributor
- "Incentives help to drive adoption." – Distributor

> "[It's] all about making the contractors aware of the benefits." – Distributor

Contractor education is also seen as a need, both to increase awareness of the viability of CCHPs in the state and to improve contractors' understanding of the benefits and cost-effectiveness of CCHPs.

Increasing Adoption

Distributers and manufacturers mentioned that Consumers Energy has been actively working to increase CCHP adoption, and they see the role of utilities as critical in helping this new technology gain a foothold.

> "The role of the utility is very important because they are the ones that can accelerate the [adoption of CCHP] technology." – Distributor

Distributers and manufacturers suggested that Consumers Energy can further encourage adoption in three ways: through education and training, by providing sales tools, and by offering incentives. Additional education and marketing directed at customers is needed to increase their awareness of the benefits of CCHPs.

> "There is a lack of information about the difference between costs for gas and electric." – Distributor

Similarly, interviewees suggested providing in-person trainings to contractors about rebates and the benefits of CCHP technology, including targeted trainings for technicians who may need more help to transition to a new technology. Three interviewees also said it would be useful to have a calculator tool that helps contractors easily demonstrate cost savings for switching to CCHP technology.

Interviewees also suggested that higher incentives would be instrumental in increasing CCHP adoption, and primarily felt that incentives should be offered via a midstream strategy. While one interviewee said rebates should be directed to contractors, all the other interviewees suggested that rebates should be directed to distributors, with one saying it would be helpful to have automatic incentives that minimize paperwork. One interviewee also suggested that incentives should be provided for CCHPs that have equivalent seasonal energy efficiency ratio (SEER) ratings as incentivized air conditioners.

> "Utility rebates really help. In some cases, the rebate has been able to cover the difference [between an AC and a heat pump]." – Distributor

Residential Market Rate Initiative Findings

In November 2021, the Evaluation team sent a survey invitation to 29 Residential Market Rate pilot participants who had valid emails. The email survey invitation included a $15 incentive for taking the survey. Nine of the 29 participants completed the survey, for a 31% response rate; with such a small sample size, the results should be interpreted with caution and only viewed as directional indications (not intended to be analyzed with statistical confidence).

In addition to the participant survey, the Evaluation team conducted an engineering analysis to determine market rate CCHP participants' energy and utility bill cost savings. The Evaluation team used data collected from the Consumers Energy initiative team and calculations that can be found in the *Michigan Energy Measures Database* (MEMD).[14]

This chapter first provides details of Residential Market Rate pilot participants, then covers the engineering analysis findings.

Market Rate Participant Survey

The Evaluation team designed the participant survey to address several key objectives:

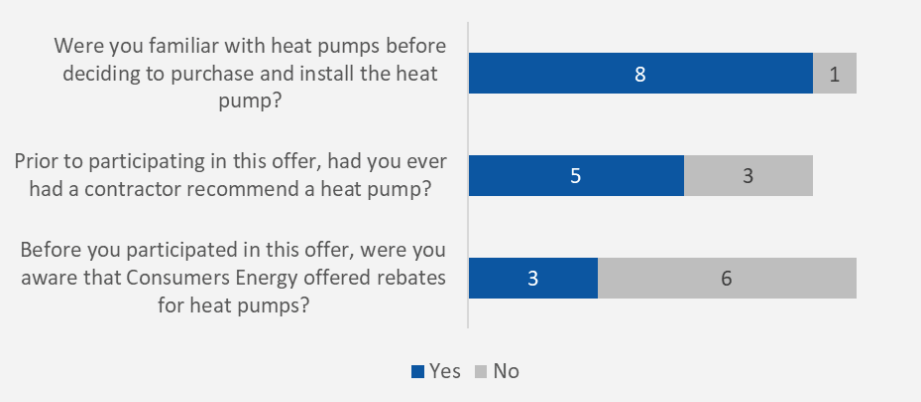
- Assess awareness of and motivation for installing heat pumps
- Assess the participant installation experience
- Document perceptions of heat pumps, energy or cost savings, and comfort levels
- Document participant usage behavior
- Assess satisfaction with the offering and with Consumers Energy

Awareness and Motivation

All nine respondents confirmed that they received a rebate for their heat pump and that they were present when the heat pump was installed. While most (eight of nine) were familiar with heat pumps before deciding to purchase one for their home, few (three of nine) were aware that Consumers Energy provided heat pump rebates (Figure 3). Respondents first learned about Consumers Energy's heat pump rebate primarily through their contractor (four of nine) or from a Consumers Energy email (two of nine). About half (five of nine) said a contractor had recommended a heat pump before they learned about and applied for the Consumers Energy heat pump rebate.

[14] Michigan Public Service Commission. *Michigan Energy Measures Database.* https://michigan.gov/mpsc/regulatory/ewr/michigan-energy-measures-database

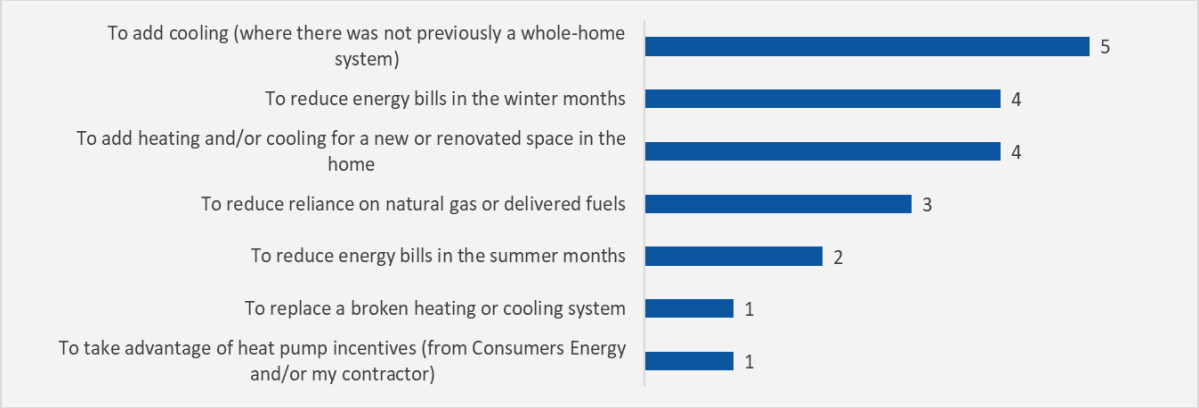
Figure 3. Heat Pump Awareness



Source: Heat Pump Market Rate Customer Survey Questions B3, B4, and B5 (n=9).

Although respondents could indicate several different motivations for installing a heat pump, responses were most frequently associated with space cooling needs and saving money on energy bills. Most respondents (n=5) installed a heat pump to add cooling where there was not previously a whole-home space cooling system. Four respondents each wanted to reduce energy bills in winter months and wanted to add space heating or cooling for a new or renovated space. Three respondents wanted to reduce their reliance on natural gas or delivered fuels (Figure 4).

Figure 4. Motivations for Installing a Heat Pump



Source: Heat Pump Market Rate Customer Survey Question B7. "What were the main reason(s) you decided to install a heat pump in your home?" (n=9; multiple responses accepted)

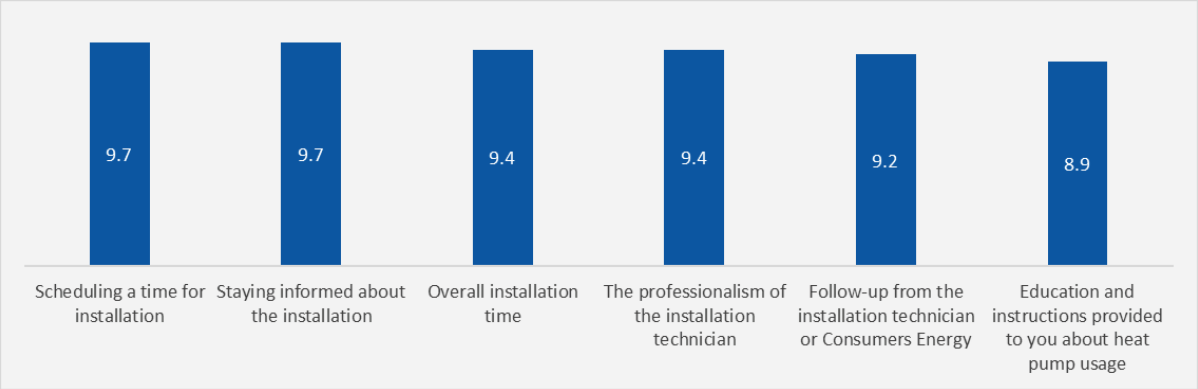
When asked to rate the importance of several factors in their decision to install a heat pump, respondents rated energy savings (over the previous heating/cooling system) as the most important (with a mean rating of 9.1 on a 10-point scale, where 1 meant *not at all important* and 10 meant *extremely important*). The contractor's recommendation received a mean rating of 8.0, and the rebate amount received the lowest rating of all decision factors, at 7.6.

Installation Experience

Respondents were engaged with the installation experience: all of them were present during the installation. Most (eight of nine) received instructions on how to set up and control the heating and cooling schedule on their heat pump at the time of installation. Only one respondent said the installation contractor set up a heating and cooling schedule for them but said they had adjusted that original schedule to address changes in their home's conditioning needs.

Respondents provided very high ratings for aspects of the installation experience, with scheduling and staying informed about the installation receiving the highest mean ratings (of 9.7 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding*; see Figure 5).

Figure 5. Installation Experience Ratings



Source: Heat Pump Market Rate Customer Survey Question D2. "How would you rate each of the following installation experiences with the heat pump offering?" (n=9)

The lowest rating (of 5) was provided by one respondent for the "education and instructions provided about heat pump usage," but that person did not answer the follow-up question about why they gave that rating.

Heat Pump Perceptions

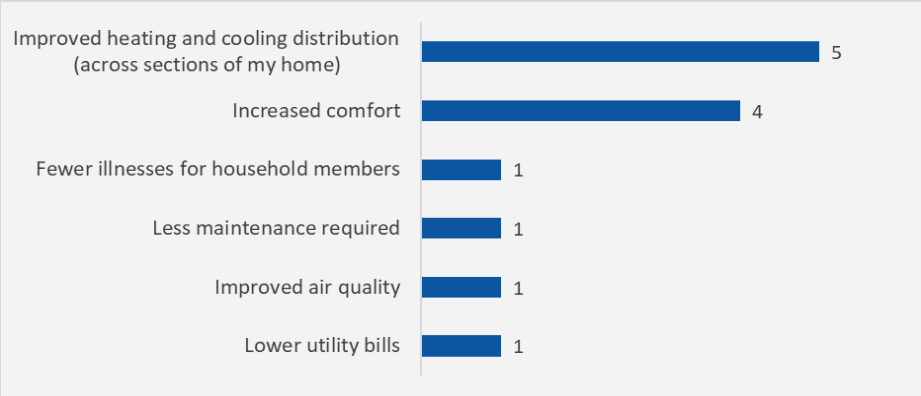
Most respondents (seven of nine) said their home is more comfortable after installing the heat pump, while the other two respondents said their home is equally as comfortable as before the heat pump was installed. One respondent also volunteered that their home air quality was vastly improved, which was also a primary reason they installed the heat pump.

Five respondents rated the comfort level provided by the heat pump in winter months, providing a mean rating of 8.6 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding*. None indicated any concerns with the heat pump's ability to heat to a preferred comfort level. Comfort ratings for summer months were higher, at an average of 9.1 with ratings from all nine respondents.

Overall, perceptions were mixed about whether respondents had seen savings on their energy bill since the heat pump was installed. Four respondents said it was too soon to tell if their energy bill was affected, while two said they had a lower-than-expected energy bill and two said they had not seen a lower-than-expected energy bill.

In addition to energy savings, respondents reported several additional benefits that they value in their heat pump. With several response options provided, the most frequent benefit selected (by five respondents) was improved heating and cooling distribution across sections of the home (Figure 6). This was followed by four respondents who said the heat pump provided increased comfort. One respondent each indicated having lower utility bills, less required maintenance, improved air quality, and fewer illnesses for household members.

Figure 6. Heat Pump Benefits

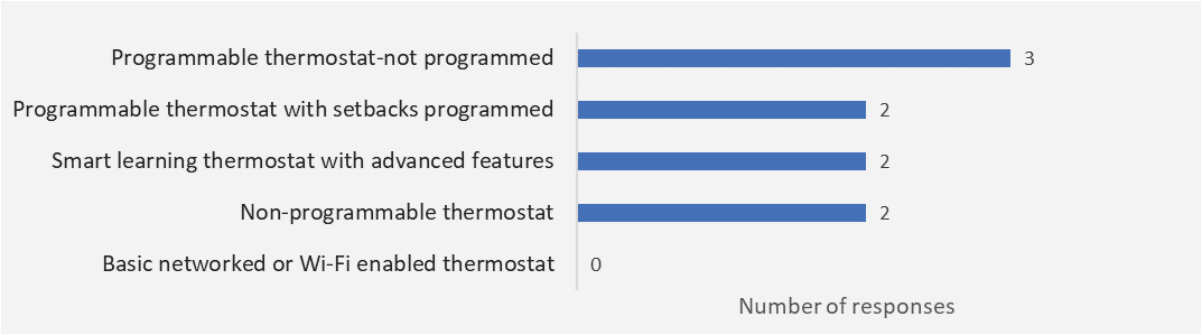


Source: Heat Pump Market Rate Customer Survey Question D13. "In addition to energy savings, if any, are there any other benefits you have experienced or observed from the installation of a heat pump?" (n=9; multiple responses accepted)

Thermostat Usage Behavior and Experience

While five of nine respondents had programmable thermostats, only two of those five used programmed temperature setbacks to control their heat pump temperature settings. Two respondents had smart learning thermostats with occupancy sensing and schedule learning capabilities, and two others had non-programmable thermostats with manual-only controls (Figure 7).

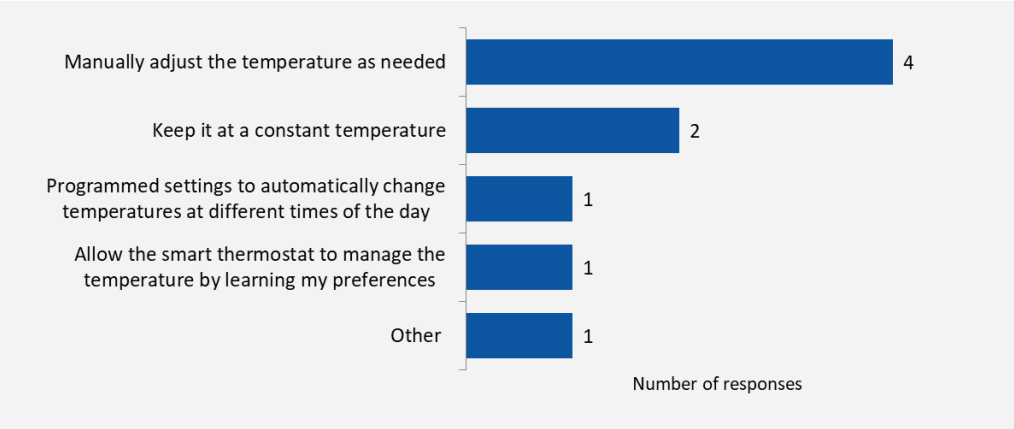
Figure 7. Respondent Thermostat Types



Source: Heat Pump Market Rate Customer Survey Question C1. "What type of thermostat do you have in your home?" (n=9)

Respondents, either singularly or with other household members, monitor and adjust the home heating and cooling settings. Despite most having programming capability through their thermostats, four of nine said they adjust the temperature manually (Figure 8).

Figure 8. Thermostat Management



Source: Heat Pump Market Rate Customer Survey Question C3. "How did your household most frequently manage your thermostat to control the temperature in your home this summer?" (n=9)

Satisfaction with the Offering and with Consumers Energy

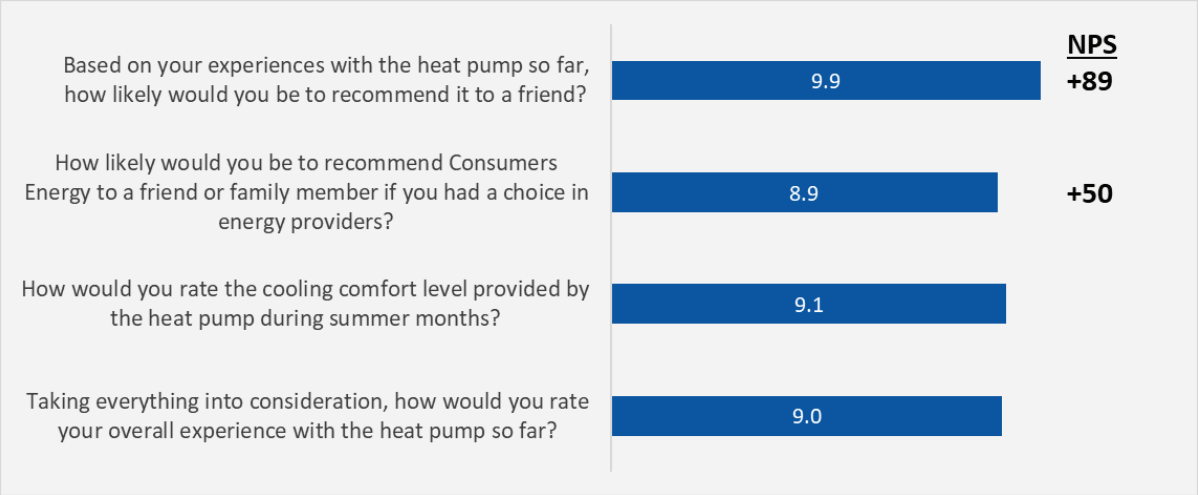
Overall, respondents were highly satisfied with the heat pump (giving a mean rating of 9.0 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding*), with all nine respondents giving a rating of 8 or higher for their overall experience with the heat pump.

Another key measure of customer satisfaction is the percentage of customers who are highly willing to recommend a product, service, or company after subtracting the percentage of customers who are highly unlikely to recommend that same product, service, or company. The net percentage of those willing to promote the product is the net promoter score (NPS), expressed as an absolute number between -100 and +100 that represents the difference between the percentage of promoters (respondents giving a rating of 9 or 10) and the percentage of detractors (respondents giving a rating of 1 to 6). The Evaluation team calculated a NPS for the two likelihood to recommend questions (likelihood to recommend the initiative and likelihood to recommend Consumers Energy).

Based on their experiences, respondents were highly likely to recommend the heat pump to a friend. As shown in Figure 9, nearly all respondents (eight of nine) gave a rating of 9 or higher (with a mean of 9.9), with three indicating that they had already recommended the heat pump rebate to a friend. The resulting NPS for the heat pump is +89.

Five of eight respondents (63%) provided a rating of 9 or 10 for their likelihood to recommend Consumers Energy to a friend. Only one respondent rated their likelihood to recommend as a 5. The resulting NPS for Consumers Energy is +50, with a mean rating of 8.9.

Figure 9. Market Rate Heat Pump Participant Satisfaction



Source: Heat Pump Market Rate Customer Survey Questions D10, B1, D7, and D9. All questions used a 10-point rating scale, where 1 meant *extremely unlikely* and 10 meant *extremely likely*, with an "already did" response option as a 10 rating (n=9).

The NPS for recommending the heat pump is considered very high and compares favorably to other efficiency programs with similar measures. For example, HVAC participants provided a program NPS of +76 and a Consumers Energy NPS of +63 in 2021. Again, caution is recommended in interpreting numeric results due to the small sample size with the Residential Market Rate pilot response population.

When asked to elaborate on their rating for recommending Consumers Energy, respondents gave positive comments:

- "Consumers Energy has been a good power company. They keep us informed on rebates, power outages, etc. During power outages they are great at restoring power quickly and keeping us informed on time frames. The rebate for heat pumps was one of the reasons we decided to try a heat pump. Our power bill has gone up, but we are using our heat pump a fair amount. It is still a better option than the window air conditioner that we had before."
- "It's been a great company. I grew up in a Consumers [Energy] home and have had one [a heat pump] my entire adult life."
- "High marks for programs and communication."
- "Very happy with service and energy offers."
- "[I] like that Consumers [Energy] is trying to help on heating costs that are going up every year."
- "We don't really have much choice, but I think that Consumers Energy does a good job providing (mostly) reliable electric service (which is all you [they] provide to my area)."

Two respondents said they do not have a choice in energy company, so they do not have a point of comparison, and one commented on high rates.

The only improvement suggestion respondents provided did not directly pertain to the heat pump initiative: "Allow me to change the energy conservation program I want more than once a year. We would like to 'follow the rules' imposed during the summer year-round but cannot change because we cancelled the program we had been on (Consumers [Energy] could limit our AC during peak periods) because our contractor did not want Consumers [Energy] to be able to change our now Wi-Fi–capable system (the old one was not [Wi-Fi]) in May/early June. We did not find out about the option we'd like until later in the summer but were not allowed to use it."

Impact Analysis

The Evaluation team conducted an engineering analysis of the impacts from the Residential Market Rate pilot and relied on MEMD assumptions and information we had collected from customers such as home vintage, presence of central cooling, installed system coefficient of performance (COP)[15] at 5°F, rated heating seasonal performance factor (HSPF) and SEER, tonnage, and other data. The Evaluation team relied on the MEMD weighting tool, which generates a single measure output based on home vintage, climate zone, sizing, and efficiency levels. Since the MEMD weighting tool does not allow for varying the baseline equipment type or system efficiency, the Evaluation team used MEMD building simulation output data to develop site-specific consumption values. MEMD staff provided underlying MEMD 2019 weighting tool building simulation results for ASHPs in single-family buildings.[16] This section summarizes key findings from the engineering analysis.

There were 42 Residential Market Rate pilot CCHPs installed in homes with electric and propane heating, making up the largest percentage of pre-installation heating fuels (Table 6). Approximately half of the CCHPs were installed in homes built before 1979 (n=25) and most of the other half were installed in homes built between 1980 and 2004 (n=23). The remaining CCHPs were installed in homes built between 2005 and present day (n=3).

Table 6. Home Construction Vintage Distribution by Pre-Installation Heating Fuels

Pre-Installation Heating Fuel	1979 or older	1980 to 2004	2005 to Present	Total
Electricity	10	6	0	**16**
Propane	9	15	2	**26**
Fuel Oil	3	1	0	**4**
Natural Gas	3	1	1	**5**
Totals	**25**	**23**	**3**	**51**

[15] Coefficient of performance is simply the ratio of power (kW) in heating (or cooling) Btus generated by the CCHP, and the power (kW) that is supplied to the compressor. The higher the COP, the greater the heating energy generated for each kilowatt consumed by the CCHP.

[16] The MEMD 2021 building simulations for this measure have not been updated since 2019 and therefore reflect the latest building simulation results.

Table 7 shows the average Residential Market Rate pilot participant' annual energy and utility bill savings by pre-installation heating fuel type. Customers heating with delivered fuels (propane and oil) realized the highest heating energy savings, while customers heating with electricity prior to installation of the CCHP had the highest utility bill savings.

Table 7. Average Market Rate Cold-Climate Heat Pump Energy and Fuel Cost Savings per CCHP

Pre-Installation Heating Fuel	Number of Installed Units	Average Savings per CCHP		Average Annual Utility Bill Savings per CCHP
		Heating (MMBtu) [a]	Cooling (kWh) [b]	
Electricity	16	35	-108	$1,680
Propane	26	68	-27	$1,223
Fuel Oil	4	70	-46	$910
Natural Gas	5	54	-228	-$451

[a] Due to the different heating fuel types, savings are represented in MMBtu to allow for better comparisons.

[b] Negative savings mean that electric consumption increased rather than decreased.

The five homes that heated with natural gas will likely see an increase in their utility bill of $451 per year on average due to the relative costs of electricity and natural gas at the time of the analysis, as well as the fact that four of five homes did not have existing central AC (which will likely increase their electric usage in the summer).

As shown below in Table 8, only 22 of the 51 participants had central AC prior to the CCHP installation. For homes without central cooling, the Evaluation team assumed a portion of the homes use room or window AC units to provide some cooling. Due to the low number of homes without conditioned cooling, electric consumption increased, on average, across all baseline heating fuel types. However, homes that did have central cooling before the CCHP installation saw savings from $20 to $96.

Table 8. Central Cooling Presence Distribution and Associated Cooling Savings

Pre-Installation Heating Fuel	Central Cooling?	Number of Installed CCHPs	Annual Cooling Electric Savings per CCHP
Electricity	Yes	5	$33
	No	11	-$37
Propane	Yes	15	$57
	No	11	-$69
Fuel Oil	Yes	1	$96
	No	3	-$35
Natural Gas	Yes	1	$20
	No	4	-$50

Table 9 shows the total Residential Market Rate pilot annual energy and utility bill savings by pre-installation heating fuel type for all CCHPs.

CADMUS

Table 9. Total Market Rate Heat Pump Energy and Fuel Cost Savings

Pre-Installation Heating Fuel	Count of Installed CCHP Units	Savings		Annual Fuel Costs [b]		Pre-Installation Central Cooling Saturation [c]
		Heating (MMBtu) [a]	Cooling (kWh)	Heating	Cooling	
Electricity	16	565	-1,729	$27,124	-$247	31%
Propane	26	1,774	-704	$31,701	$85	58%
Fuel Oil	4	279	-183	$3,652	-$10	25%
Natural Gas	5	270	-1,142	-$2,072	-$182	20%

[a] Due to the different heating fuel types, savings are represented in MMBtu to allow for better comparisons.

[b] The Evaluation team calculated annual heating and cooling costs based on rates and distributed fuel cost shown in *Appendix B*.

[c] Not every home was equipped with central cooling before the CCHP installation.

Income Qualified Multifamily Initiative Findings

There are two key groups of participants in the Income Qualified Multifamily initiative: property owners and managers (PMO) and tenants. PMOs are active participants who sign up for the initiative and are the primary contacts of the initiative. The tenants are indirect participants; they are not decision-makers, yet they directly benefit from the CCHP Initiatives' equipment and energy savings in their living units and they most frequently pay the resulting energy bills from CCHP operation. The Evaluation team sought feedback from both groups, conducting telephone interviews with PMOs and online surveys with tenants. The Evaluation team also sought to understand the Income Qualified Multifamily initiative's performance by analyzing electric energy savings impacts during the heating and cooling seasons through a statistical billing analysis of participating initiative properties.

This chapter outlines the results of PMO interviews, tenant surveys, and the statistical billing analysis.

Property Manager and Owner Interviews

The Evaluation team conducted telephone interviews with multifamily PMOs who participated in the CCHP initiative to gain insight into their experience. The Evaluation team designed the interview to address several key objectives:

- Document the participant installation experience
- Document participant usage behavior and experience
- Document awareness and perceptions of heat pumps
- Document participant decision-making around participating in the heat pump offering
- Identify marketing and outreach best practices
- Assess satisfaction with the offering and with Consumers Energy

As of Q3 2021, seven multifamily properties had participated in the Income Qualified Multifamily initiative. While the Evaluation team attempted to recruit all seven of the multifamily PMO initiative participants, we completed three phone-based in-depth interviews. Two of the multifamily PMO participants were from existing buildings (retrofit installations) and therefore had broad insights into the full initiative experience. The third interviewee was with a newly constructed property, which meant they had a more limited view on the tenant and installation experience.

Installation Experience

Overall, the multifamily PMOs had a positive early-stage initiative experience with scheduling, installation, and follow-up. Two of the three PMOs reported that COVID-19 caused some delays with the installation and equipment, but overall reported positive experiences. In one case, the PMO commented that the completion time was fast considering the number of units and installs: "We had something like 48 units, some large enough for multiple installations…so two-and-a-half months to install over 50 units was fast." The third PMO, the owner of a new construction property, noted the while installations were all completed on time, they did not have feedback on the tenant experience during installation (as installation happened before tenants occupied the units). For the other two PMOs with tenants living in

the units, the installer worked directly with management to notify the tenants of the installations and work around their schedules. According to these two PMOs, their tenants were generally satisfied with the heat pump installation.

Heat Pump Usage Behavior and Experience

The multifamily PMOs reported that prior to installation, tenants relied on inefficient electric baseboard systems and, in one case, had specifically requested new a HVAC system during a tenant meeting. One of the primary benefits for tenants is the ability to use AC as well as heating—while the heat pump replaced baseboard heat, there was no existing AC to replace outside of window units purchased by tenants. One PMO mentioned that nearly all tenants enjoyed the new heat pumps, with only a few tenants being confused about how to use the new system.

Two of the multifamily PMOs received direct feedback from their tenants regarding the heat pump usage and experience. According to one PMO, “the residents considered it a huge plus for them, because of all the extra benefits that the heat pumps provided them.” Another PMO remarked that the heat pumps provided significantly greater comfort, and improved air circulation, compared to the baseboard equipment, and went on to state, “the heating itself is just more efficient for the tenants; it seems to keep the apartments warmer.”

Awareness and Perceptions of Heat Pumps

Multifamily PMOs were generally aware of heat pumps prior to being approached by Consumers Energy about the rebate initiative, though they were not aware of Consumers Energy incentives or programs until their involvement in the initiative. One PMO previously had contractors recommend heat pumps, while another had heat pumps installed in other apartments in the Southeast United States (where heat pumps are more common). One of the PMOs had some hesitation about installing the CCHPs, as they noted, “historically, my understanding was that [heat pumps] didn’t do so well in cold climates. A green consultant and several HVAC engineers turned me on to them and then [I] became comfortable [that] they would be sufficient.”

PMOs generally did not report any perceived benefits of heat pumps prior to installation but were happy to report both energy and non-energy benefits, particularly tenant happiness and reduced maintenance and tenant comfort needs, after installation. As an added benefit, the simplicity of a single heating and cooling system was beneficial for both tenants and the PMOs: the number one benefit is providing heat, but efficient heat is the next important thing. As one PMO said, “There is always some kind of system [to heat], but it doesn’t always work. It’s always our number one concern to provide heating and cooling to the tenants.”

Decision-Making around Participating in the Heat Pump Offering

In both existing retrofit cases, the PMOs primarily decided to improve the existing HVAC systems due to energy efficiency and tenant comfort. One PMO cited a tenant meeting as a primary factor, where tenants explicitly requested an improved HVAC system. Generally, all PMOs wanted to improve tenant comfort, replace old equipment, improve electric efficiency, and lower electricity bills. The biggest barrier to switching over to heat pumps was cost: because the multifamily buildings already had existing

heating systems, it was a matter of prioritizing which are the most in need and how to fit that into the budget: "… if there is an existing heating system that is working, that's not necessarily something we can improve because it meets [the need for] having a functioning system, and it's harder and more expensive to switch out than other properties… so the biggest barrier is a matter of prioritizing it [CCHP installation] in the budget." According to the other retrofit PMO, the rebate allowed them to fit improved HVAC systems into the budget for that year. Tenant comfort, energy efficiency, and an improved system were the key motivations for PMOs.

For the new construction PMO, heat pumps were an attractive investment for their property, and the initiative made it "a slam dunk" for the project. The initiative allowed the property to meet LEED certification while also managing to keep the construction within budget. As the new construction PMO noted, "for our LEED-certified property, which was an all-electric building, and given [that] the units were smaller apartments, it was hard to find a furnace that would work well and integrate into the units and not be oversized. The heat pumps can really work well and are adapted to lower need, relative to [a] gas furnace. The simplicity of only electric, with no gas, requiring less piping, meant that construction was easier." This PMO went on to remark, "with the rebate, the heat pump was actually the cheaper option [relative to a gas furnace]."

Marketing and Outreach Best Practices

Multifamily PMOs agreed that the best way to conduct outreach about CCHPs is to directly contact contractors or developers. According to two PMOs, they primarily get their recommendations from contractors, who do not always provide information on CCHPs and higher-efficiency opportunities to the developers. One existing building PMO said, "if I had someone directly to talk to, I would bring this up to [building owners] more…I confer with architects and specialists on building recommendations, but they don't necessarily know all the tenant benefits. So, I would recommend reaching out to more developers, like myself, directly." Both PMOs recommended emails or pamphlets with the overall costs and energy savings and direct information as a convincing outreach strategy: "Anything that involves a description, some costs, energy savings…I think those are the highlights," the construction manager said.

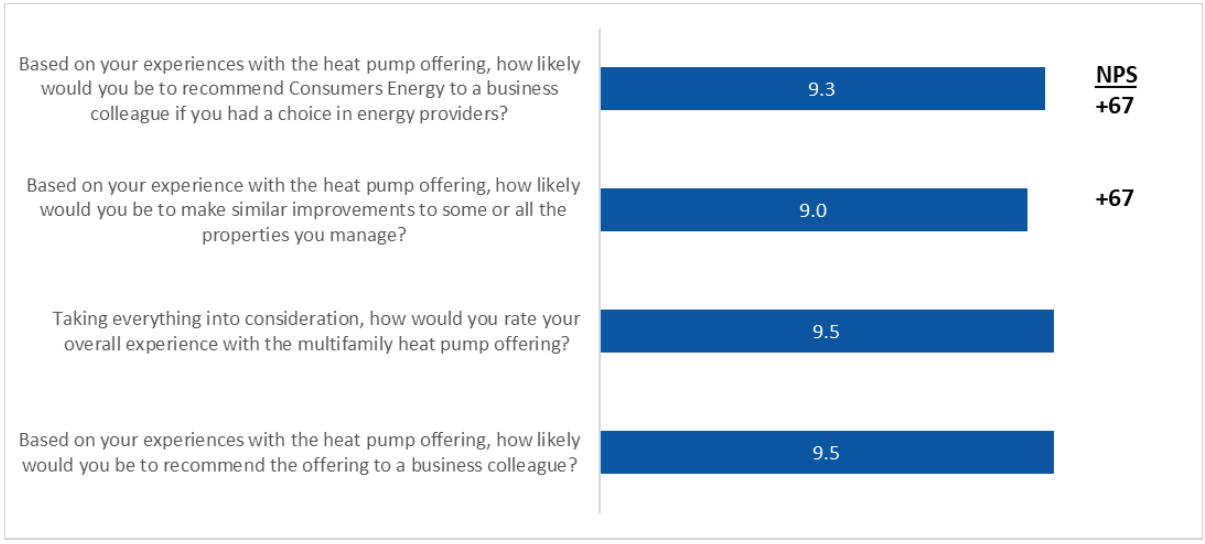
Two of the PMOs learned about the heat pump offering through direct contact with Consumers Energy, while one learned about it from their LEED consultant. When asked what the preferred means of communicating future offerings, all three PMOs tended to prefer email, but also noted phone calls.

One interviewee (the resident manager) mentioned that his property manager was the decision-maker in the process, and that energy companies should do more to contact property managers directly, because most are not aware. "[The property manager] was different," the resident manager said, "He was always searching for rebates and things like that…both to improve the apartments for the tenants, but also because of the resource—using less energy is good for the economy, that kind of thing. But most property managers aren't searching like he was." Another PMO said, "Most people don't know enough and aren't aware [that heat pumps] can work on their own in colder climates. We have now had a full winter with new tenants and the CCHPs and received no complaints: it all went well."

Satisfaction with the Offering and with Consumers Energy

Overall, the participating PMOs were highly satisfied with their initiative experience and with Consumers Energy (Figure 10). The three PMOs provided an average rating of 9.5 on a 10-point scale (where 1 meant *unacceptable* or *extremely unlikely* and 10 meant *outstanding* or *extremely likely*) for their satisfaction with the initiative and their likelihood to recommend heat pumps to a colleague. The PMOs also rated their likelihood to recommend Consumers Energy as a 9.3 and rated their likelihood to adopt similar CCHP equipment in their other properties as a 9.0 (Figure 10).

Figure 10. Multifamily Property Manager Owner Cold-Climate Heat Pump Satisfaction



Source: Heat Pump Property Owner and Manager Interview Guide Questions G1–G4.

Income Qualified Multifamily Tenant Survey

In November 2021, the Evaluation team surveyed a group of multifamily tenants who resided in units that received CCHPs as part of Consumers Energy's CCHP initiatives and 32 completed the survey

The Evaluation team designed the survey to address several key objectives:

- Document awareness of heat pumps
- Understand the participant installation experience
- Assess tenant perceptions of heat pump impacts on comfort levels and electricity bills
- Document participant usage behavior and experience
- Assess satisfaction with the offering and with Consumers Energy

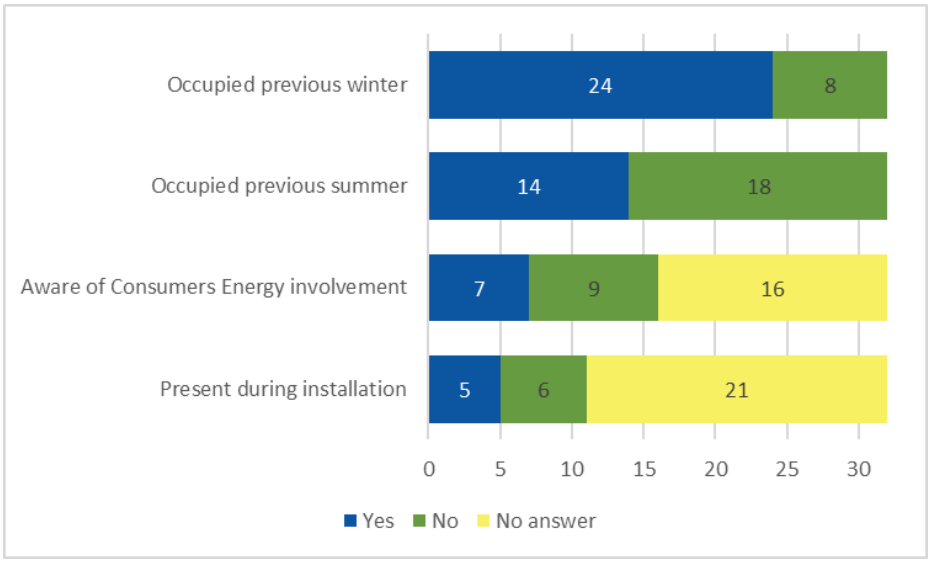
Tenant Survey Background

The multifamily tenant survey included questions about topics such as whether respondents manage the temperature of their unit, whether they pay their bills, and how long they have resided in their unit. Additionally, the team asked questions about the installation and performance of the CCHP.

All tenants who responded to the CCHP survey managed the temperature of their home personally and all said they pay their own energy bills (n=32). Most tenants (n=17) had lived in the apartment for between six months and one year while 11 others had occupied their apartment for more than one year. Additionally, three respondents said the heat pumps had not yet been completely installed and they could not provide answers about installation or post-installation.

Other participant characteristics are summarized in Figure 11. A minority of respondents were present during installation (n=5) and were aware of Consumers Energy involvement in the CCHP (n=7). Three-quarters of respondents were occupants last winter (n=24), before the installation, while one-quarter (n=8) were not present in their units to experience the old heating system, and thus could not provide comparative responses about new versus old heating system performance. Respondents' tenancy term and other factors resulted in around one-third (30%) of the responses to all questions that provided little to no insight into their experience in this initiative. Because of the low response count to many of the tenant survey questions, the results should be considered indicative but inconclusive.

Figure 11. Summary Respondent Characteristics



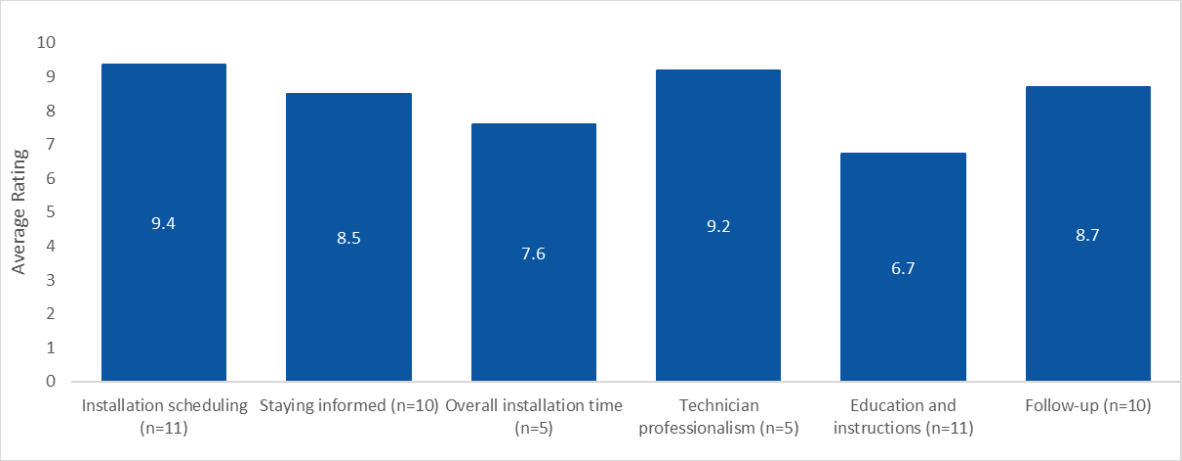
Source: Heat Pump Multifamily Tenant Survey Guide Questions C5, C8, B3, and C1. Please see *Appendix E* for specific question wording.

Participant Installation Experience

A successful equipment installation can provide tenants with a positive initiative experience; such an installation should include providing helpful information and operational details for a better managed heating and cooling experience. One-third of respondents (n=11) provided installation experience ratings. Overall, participants were largely satisfied with the installation experience, rating most installation elements above an 8 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding* (Figure 12). Respondents provided the lowest average rating to the education and instructional aspects of installation, which impacted their overall satisfaction with the heat pump

offering, as well as with Consumers Energy overall (these metrics are featured further below in Figure 19).

Figure 12. Tenant Installation Satisfaction

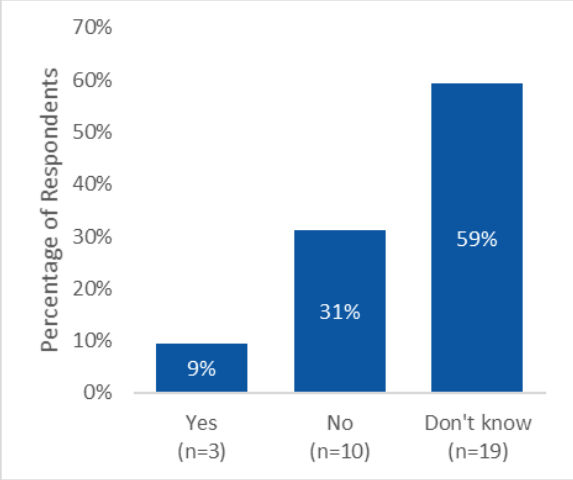


Source: Heat Pump Multifamily Tenant Survey Guide Question C2. "How would you rate each of the following installation experiences with the heat pump offering?"

Participant Usage, Behavior, and Experience

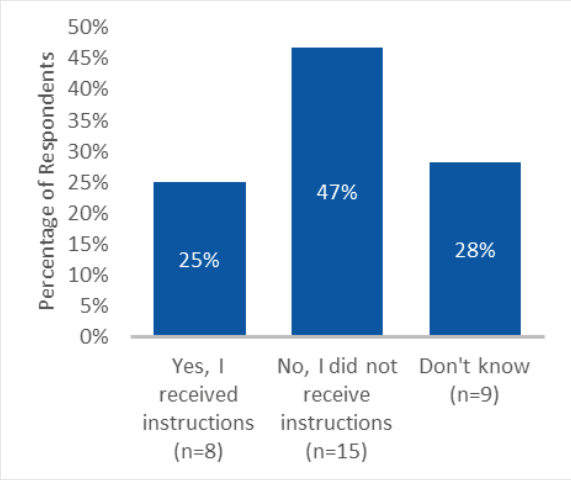
Participant usage, behavior, and experience with this offering were influenced by the installation technicians and education surrounding the CCHP equipment installation. Only three respondents could confirm with certainty that the technician set up a heating and cooling schedule for their heat pump (Figure 13). These three participants also confirmed that the heating and cooling schedule set up by the contractor is still in operation. Lack of heat pump education, materials, and follow up were common among respondents. Forty-seven percent of participants (n=15) reported not receiving documentation or instructions about the heat pumps, while 28% (n=9) did not know if they received instructions and 25% (n=8) did receive instructions (Figure 14). Other survey respondents indicated in open-ended responses that there was a lack of information relayed about the heat pumps, either from installation technicians, the PMOs, Consumers Energy, or a combination of the three.

Figure 13. Heating and Cooling Schedules



Source: Heat Pump Multifamily Tenant Survey Guide Question C16. "Did the installation technician set up your heat pump on a heating and cooling schedule?"

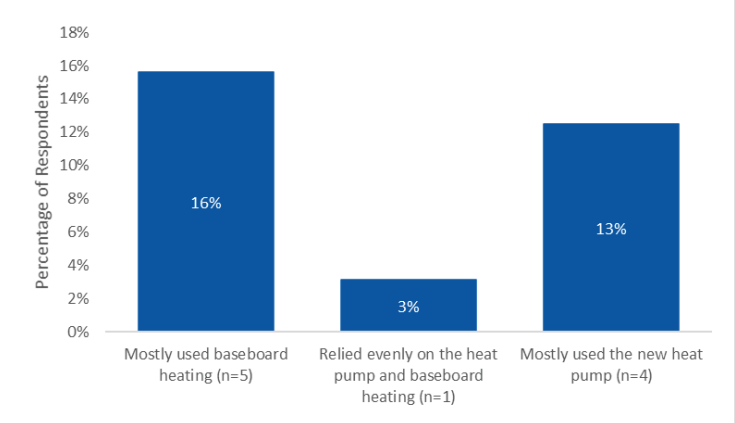
Figure 14. Instructions Provided at Installation



Source: Heat Pump Multifamily Tenant Survey Guide Question C18. "Have you been provided with instructions on how to set up and control your heating and cooling schedule on your heat pump?"

Sixteen percent (n=5) of participants reported using mostly baseboard heating after installation, while 13% (n=4) reported using mostly the newly installed heat pump and 3% (n=1) reported using both evenly. Another 68% (n=22) of participants did not know which heating source they relied on.

Figure 15. Primary Multifamily Tenant Apartment Heating Source



Source: Heat Pump Multifamily Tenant Survey Guide Question C12. "Which of the following best describes how you heated your apartment last winter?"

In open-ended responses, some tenants were unhappy with the lack of information:

- "After the installation, there was not follow up. Also, there are many in our complex that have no idea on how to set up the mobile app."
- "Manager of my complex did not [educate] me on how to use all the features. Also, when and who changes the filters, if any."

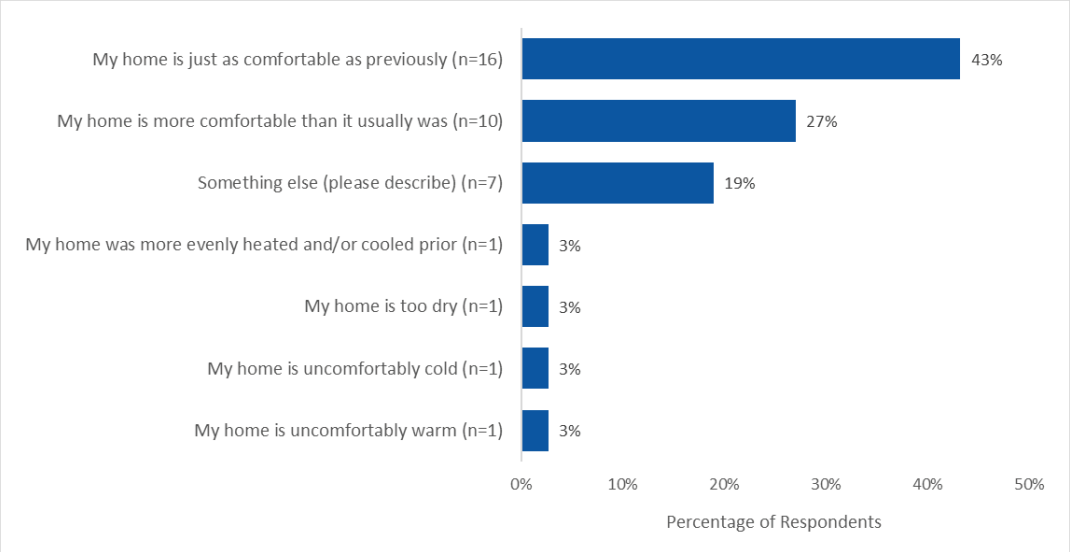
Awareness and Perceptions of Heat Pumps

Most participants (68%; n=21) reported a complete lack of knowledge regarding heat pumps, even after installation. More interestingly, half were not aware that there was a heat pump installed in their apartment, despite having occupied the unit at the time of installation. Of the half that were aware of the heat pump installation, 56% (n=9) did not know Consumers Energy was involved in the project. In an open-ended response, one participant was surprised: "I didn't know anything about how to run the heat pump or maintenance needed. We weren't told anything. We didn't even know Consumers [Energy] funded it."

Perceptions of Heat Pump Impact on Comfort Levels and Electricity Bills

As noted above, PMOs indicated tenant comfort was a key factor in the decision to participate in the heat pump initiative—some tenants supported this perception. Post-installation, although 43% of tenants reported their homes to be as comfortable as before, one-quarter of tenant survey respondents reported increased comfort (27%). Specifically, few tenants reported issues with temperature or humidity regulation, as shown in Figure 16.

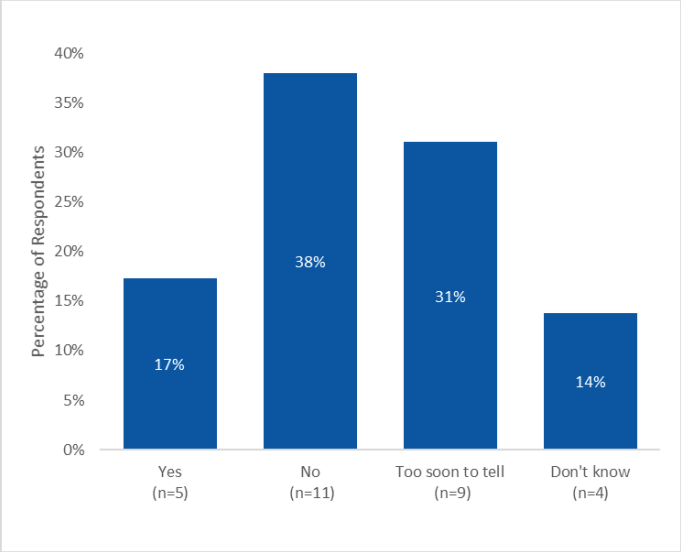
Figure 16. Heat Pumps and Home Comfort



Source: Heat Pump Multifamily Tenant Survey Guide Question C11. "In general, how did the heat pump affect your home comfort?"

Over twice as many income-qualified multifmaily respondents believed they did not experience any savings on their energy bills as those who believed they did experience savings: 38% of respondents (n=11) reported no savings on their energy bills, compared to 17% (n=5) who reported savings (Figure 17).

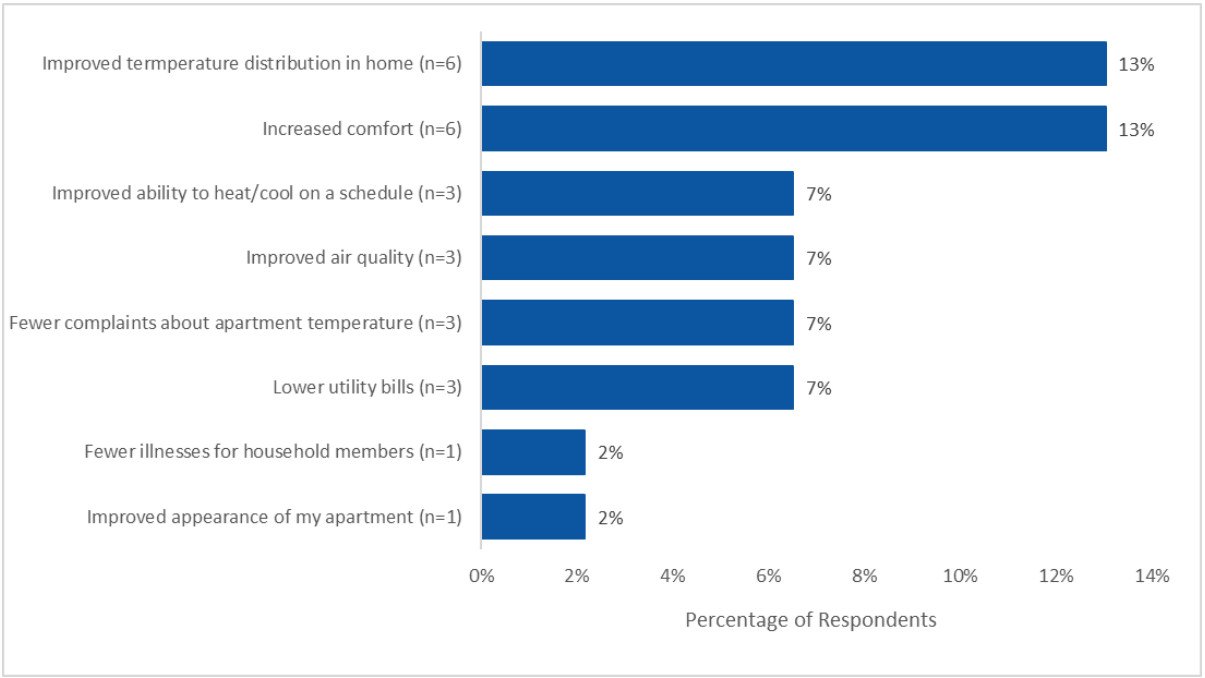
Figure 17. Multifamily Tenant Energy Bill Savings



Source: Heat Pump Multifamily Tenant Survey Guide Question D2. "Have you seen a lower-than-expected energy bill?"

Even with few respondents believing the CCHPs resulted in bill savings, a high number reported non-energy saving benefits of the CCHPs, primarily related to temperature distribution and comfort (Figure 18).

Figure 18. Non-Energy Benefits



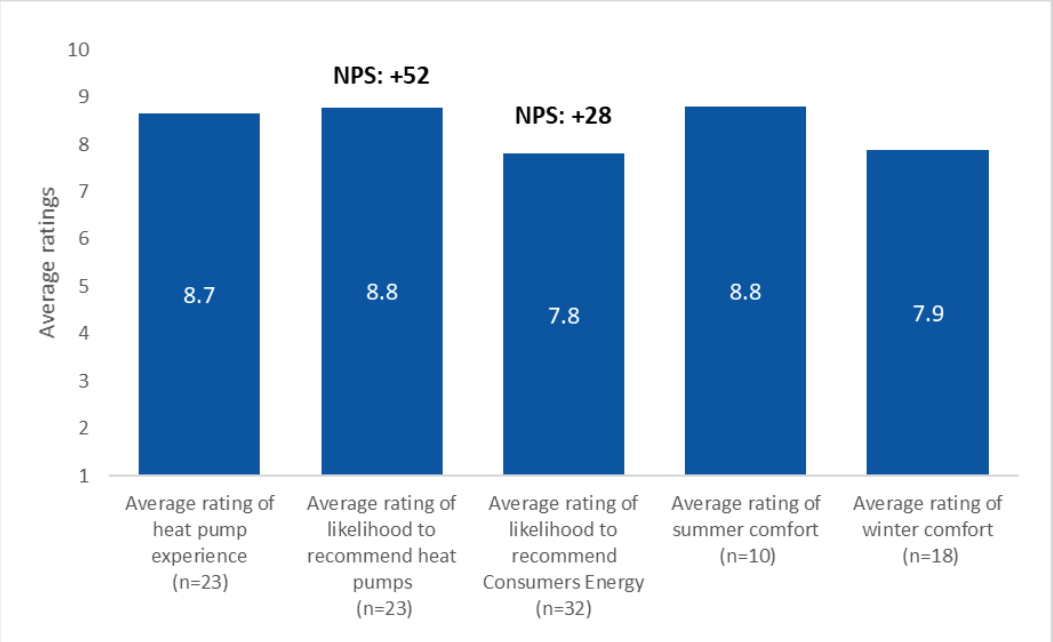
Source: Heat Pump Multifamily Tenant Survey Guide Question D3. "In addition to energy savings, if any, are there other benefits that you have experienced or observed from the installation of heat pumps?"

Satisfaction with the Offering and with Consumers Energy

Income-qualified multifamily tenants were satisfied with the CCHP experience, and generally felt that the heat pumps provided improved winter heating and summer cooling comfort. CCHP multifamily tenant participants reported an average rating of 8.7 regarding their overall experience with the heat pump, an average of 8.8 rating on likelihood to recommend a heat pump to a friend, and an average of 7.8 rating on likelihood to recommend Consumers Energy, all on a 10-point scale where 1 meant *unacceptable* or *extremely unlikely* and 10 meant *outstanding* or *extremely likely* (Figure 19). Respondents also reported an average rating of 8.8 regarding summer comfort and 7.9 regarding winter comfort.

Another key measure of customer satisfaction is the percentage of customers who are highly likely to recommend a product, service, or company after subtracting the percentage of customers who are highly unlikely to recommend that same product, service, or company. The net percentage of those willing to promote the product is the net promoter score (NPS), expressed as an absolute number between -100 and +100 that represents the difference between the percentage of promoters (respondents giving a rating of 9 or 10) and the percentage of detractors (respondents giving a rating of 1 to 6). The Cadmus team calculated a NPS for the two likelihood to recommend questions (likelihood to recommend the CCHPs and likelihood to recommend Consumers Energy – see Figure 19 below).

Figure 19. Satisfaction with Cold-Climate Heat Pump Experience and Comfort



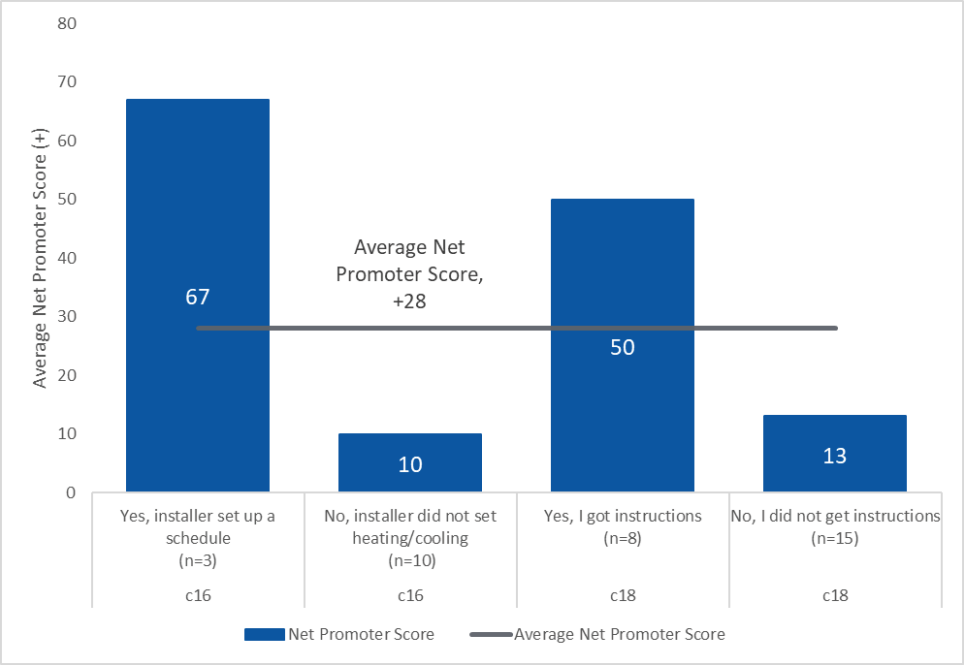
Source: Heat Pump Multifamily Tenant Survey Guide Questions E1, E2, A1, C9, and C6. Please see *Appendix E* for specific question wording.
This figure reflects combined average satisfaction ratings of heat pump experience and comfort.

The Evaluation team also calculated a NPS for the two likelihood to recommend questions (likelihood to recommend the CCHPs and likelihood to recommend Consumers Energy). As shown in Figure 19, based

on experiences with the heat pump, respondents were somewhat likely to recommend the heat pump to a friend. Though 14 respondents were promoters (providing ratings of 10) and only two were detractors, nine respondents did not provide a rating and seven were passives. The resulting NPS for the heat pump was +52. Sixteen respondents provided a 9 or 10 rating for likelihood to recommend Consumers Energy to a friend while seven provided ratings below a 7 and were classified as detractors (nine respondents were classified as passives). The resulting NPS for Consumers Energy was +28.

The Evaluation team compared the Consumers Energy NPS across different participant groups (Figure 20). Participants who provided low ratings on installation communication and instructions and provided verbatim feedback around lack of education materials and instructions were more likely to provide a lower overall Consumers Energy NPS. In fact, this cohort on average provided the lowest ratings of all participants. Additionally, participants who received instructions or had their heating and cooling schedule set by installation technicians had a higher NPS on average than both the survey average and the average of those who had no instructions or schedule set.

Figure 20. Average Consumers Energy Net Promoter Score and Installation Satisfaction



Source: Heat Pump Tenant Survey Guide Questions A1, C16, and C18. “How likely would you be to recommend Consumers Energy to a friend or family member if you had a choice in energy providers?” “Did the installation technician set up your heat pump on a heating and cooling schedule?” and “Have you been provided with instructions on how to setup and control your heating and cooling schedule on your heat pump?”

Open-ended responses regarding Consumers Energy were primarily positive in nature, though some were frustrated with Consumers Energy's service, mostly reporting high bills:

- "Great customer service and payment plans. But the cost in the winter is way higher than I think it should be."
- "My bill was all over the place last winter reaching almost $300 between two small school-aged kids who were gone most of the day and myself who unplugs everything."
- "Because I'm low income with social security income where there's no assistance help for my electric bill, the bill can be extremely expensive."

Nearly all positive responses cited great customer service and the ease of payment:

- "Service has been great for me in as long as I've been with them."
- "Good service and consistent customer service."
- "Very easy online payments and very easy outage center updates. It's also nice to have those text and email reminders about billing."

Impact Analysis

This section summarizes findings from the Evaluation team's statistical billing analysis, conducted to determine electric energy savings resulting from the Income Qualified Multifamily initiative. While the focus of the initiative and the billing analysis were on electric-heated properties (and therefore on electric impacts on heating use during the winter heating season), the Evaluation team also used the billing analysis to determine the electric energy impacts associated with summer cooling season. *Appendix B* has a detailed discussion of the methodological approach we used to determine the energy savings.

Key Findings

The Evaluation team estimated the electric energy impacts of CCHP installations separately for winter electric heating and summer cooling impacts. The Income Qualified Multifamily initiative participant electric savings results, presented in Table 10, show winter electric heating energy savings of 832 kWh, equivalent to 22.9% of baseline weather-sensitive electric heating use.

Table 10. Multifamily Income Qualified Heat Pump Electric Energy Savings

Group	Weather-Sensitive Electric Usage (kWh)		Weather-Sensitive Electric Savings		Precision at 90%
	Pre-Period	Post-Period	kWh	Percentage	
Winter heating	3,626	2,794	832	22.9%	±9%
Summer cooling	234	170	64	27.1%	±24%
Total Annual (Weather Sensitive)	3,860	2,964	896	23.2%	±8%

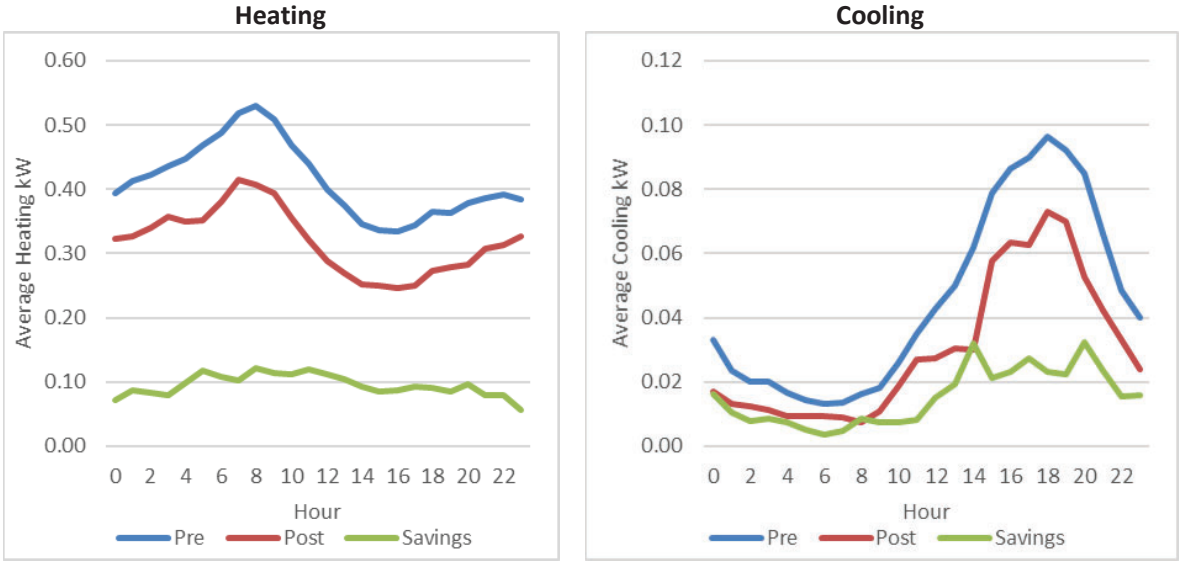
Source: Evaluation team billing analysis.

The billing analysis estimate of 64 kWh savings per unit during the summer cooling season reflected a similar percentage reduction in weather-sensitive electric usage attributable to the CCHPs (at 27%

relative to the 23% for winter heating). The heating electric analysis produced savings estimates within the ±10% precision threshold at a 90% confidence interval and therefore the results were statistically significant. Given the lower cooling load and therefore more variable signal, the cooling savings were outside the ±10% precision target. Overall, the Income Qualified Multifamily initiative resulted in a statistically significant annual reduction of 896 kWh for each participant tenant unit, representing 23.2% of the annual weather-sensitive electric energy use and translating into approximately $147 in annual bill savings for each CCHP participant.

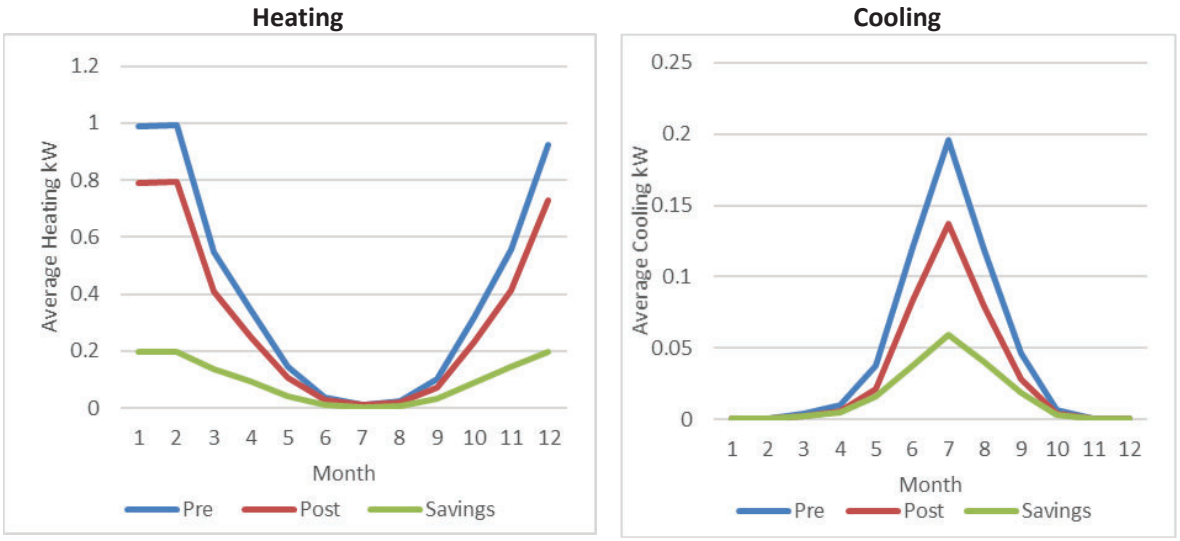
An examination of the heating and cooling load shapes and accompanying savings profile offers insight into how the CCHP impacted heating and cooling usage. Figure 21 shows the average winter and summer daily load shape and resulting CCHP savings profiles. In the winter, participants' CCHP electric energy savings were relatively consistent throughout the day. In the summer, the CCHP cooling savings were coincident with the cooling load periods of mid-to-late afternoons.

Figure 21. Participant Hourly Heating and Cooling Load and Resulting Savings



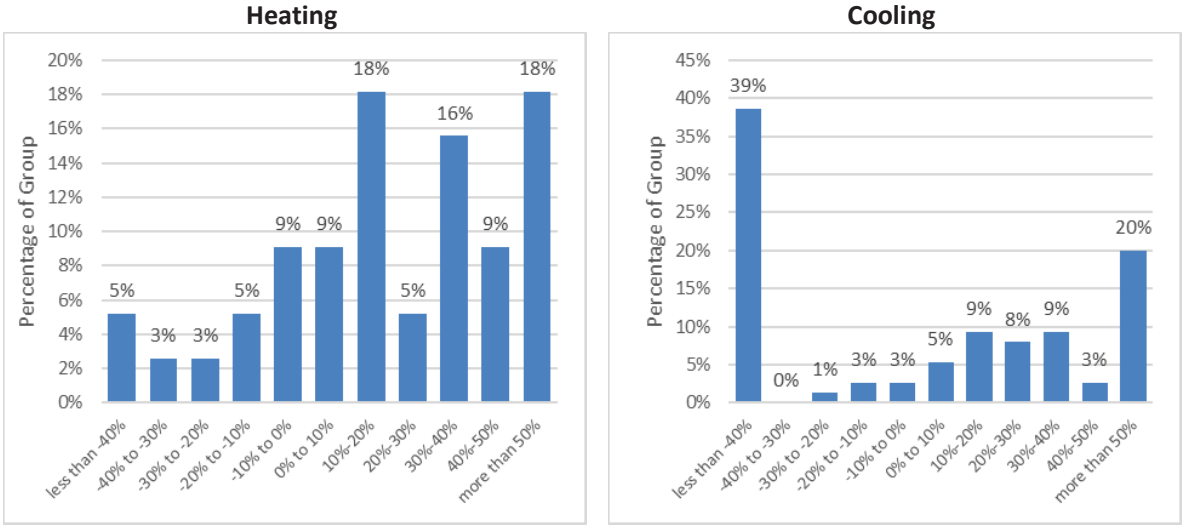
An examination of the average *monthly* load and savings profiles also showed that the savings were consistent with the monthly load shapes (Figure 22).

Figure 22. Monthly Heating and Cooling Load and Resulting Savings



The Evaluation team also explored the variability of savings across the tenant units by grouping the percentage of tenant units according to decile savings bins (incremental steps of 10% savings; see Figure 23). More than 40% of the Income Qualified Multifamily tenants saved over 30% of their pre-installation electric energy during the winter heating season, while the largest group of customers (18%) saved over 50%. On the summer cooling analysis, close to 40% of Income Qualified Multifamily customers had a net increase in summer electric use. These customers likely lacked any pre-installation cooling equipment (no room ACs) or were unlikely to have used their equipment. The second largest group of customers were also the highest saving group, with 20% of the tenants saving over 50% of their pre-installation summer cooling electricity usage.

Figure 23. Percentage Distribution of Annual Heating and Cooling Savings by Savings Bin



Benchmarking of Results

The Evaluation team compiled results from three recent multifamily heat pump retrofit program evaluations in other regions to understand how the results compared to the Consumers Energy Income Qualified Multifamily initiative. A majority of the evaluations were focused on income-qualified properties. As shown by the summary benchmark data in Table 11, the Income Qualified Multifamily initiative findings are consistent with other multifamily income-qualified billing analysis results.

Table 11. Benchmarking of Multifamily Heat Pump Billing Analysis Results

Utility and Program	Percentage Savings	Home Type	Income	Analysis Type
Consumers Energy Income Qualified Multifamily initiative	**23.2%**	**Multifamily**	**IQ**	**Billing Analysis**
2020 Commonwealth Edison Multifamily Income-Qualified Heat Pump pilot (full report not yet public but summary report is here)	25%	Multifamily	IQ	Billing Analysis
2016 Efficiency Maine Low-Income Multifamily Weatherization program (report)	22.2%	Multifamily	IQ	Billing Analysis
2014 Connecticut Energy Efficiency Fund Home Energy Services (Income Eligible) (report available online)	11% [a]	Multifamily	IQ	Billing Analysis
2014 Energy Trust of Oregon Multifamily Ductless Retrofits (report available online)	15% [a]	Multifamily	Any	Billing Analysis
Puget Sound Energy Heat Pump Dealer Channel (not public)	18% [a]	Single Family	Any	Billing Analysis

[a] This represents the percentage of annual load, not the percentage of weather-sensitive load (which was not reported).

CADMUS

Commercial and Industrial Cold-Climate Heat Pump Pilot Findings

Consumers Energy developed its Commercial and Industrial Cold Climate Heat Pump Pilot initiative in 2020 in response to the 2020 Consumers Energy Settlement Agreement with the Michigan Public Service Commission and other stakeholders. Beginning in early 2021, Consumers Energy launched the initiative targeting small commercial and industrial customers, defined as customers with facilities under 20,000 square feet. Initiative staff reached out to customers who did not have access to natural gas or were suspected to have propane heat. Staff then helped these customers choose a contractor to install a CCHP, addressed any questions the participants had throughout the installation process, and provided significant financial support to install new CCHPs; all but one customer had the entire cost fully covered.

For this research, the Evaluation team conducted in-depth telephone interviews with initiative participants to address several key research objectives:

- Explore key factors in customer decision-making regarding CCHP installations
- Explore customer experiences during the CCHP installation process
- Explore customer experiences using their CCHP
- Explore customer experiences with the initiative offering
- Identify opportunities to best support CCHP technology moving forward

In the fall of 2021, the Evaluation team conducted in-depth interviews with seven of the nine initiative participants, asking about heat pump technology awareness and motivations for participation, as well as participant experiences and satisfaction throughout the initiative process and with their new heat pump technology. During the winter of 2021/2022, the Evaluation team also metered the equipment to assess energy savings. Findings from this research are found in the 2021 Cold Climate Heat Pump Pilot Impact Evaluation Memo submitted as part of Consumers Energy's 2021 reconciliation. Metering for the 2022 cooling season is still in progress as of the writing of the report, and analysis and reporting will take place later in 2022.The remainder of this section presents findings from the participant interviews.

Participant Interviews Findings

In Fall 2021, the Evaluation team conducted in-depth interviews with seven Small C&I Initiative participants who were either the business owner or a key decision-maker related to the business. The subsections below describe how customers heard of and then decided to participate in the initiative offering, followed by installation experiences, heat pump use experiences, and overall initiative experiences and satisfaction. Additional details are available in the *C&I 2021 Cold Climate Heat Pump Pilot Customer Interview Results Presentation* submitted as part of Consumers Energy's 2021 reconciliation.

Decision-Making Processes

The Evaluation team asked participants about their awareness and understanding of heat pump technology, their plans to replace existing heating equipment, as well as their concerns, considerations, and motivations for installing the heat pumps.

Participants in the Small Commercial initiative were generally not familiar with heat pumps prior to being contacted by Consumers Energy staff. Over two-thirds of respondents (71%; n=5) were *not at all familiar* with heat pumps prior to the initiative. One respondent said they were *somewhat familiar* and had read some articles about heat pumps, but not enough to have purchased a heat pump without the support from the initiative. Another respondent said they were *very familiar* with the technology, but was under the impression that heat pumps were not suitable for Michigan winters.

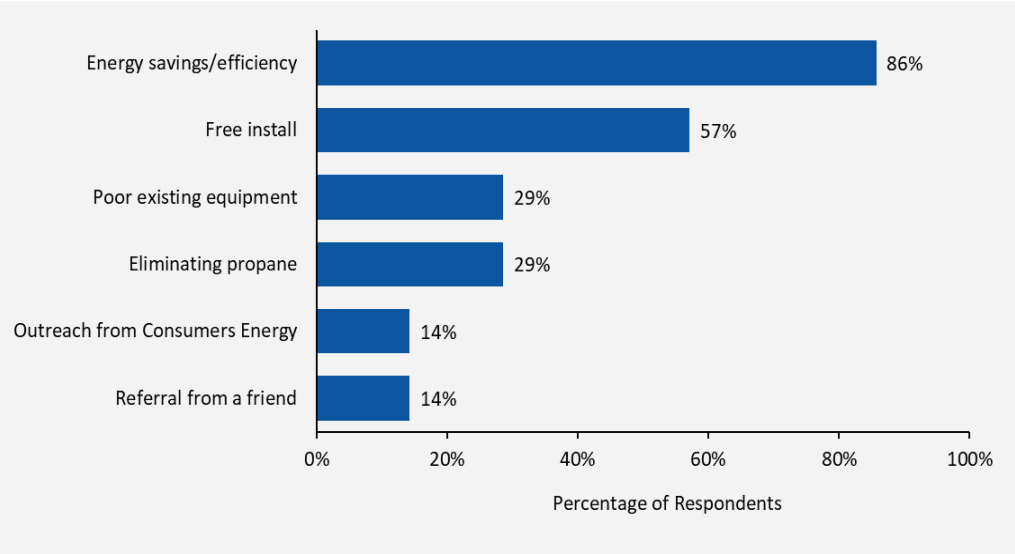
When asked about their existing heating and cooling equipment, all respondents reported having a propane furnace prior to installing their heat pumps, and 86% (n=6) had central AC. While four respondents had no immediate plans to replace their existing equipment, 43% (n=3) had planned to replace their heating equipment within the next one to three years, and all three would likely have replaced their furnace with a new propane furnace. This finding suggests that customers likely would not have considered a heat pump as an option if not for the initiative, despite some respondents reporting low satisfaction with their propane service.

When asked about their concerns and considerations when deciding to install a heat pump, respondents were primarily concerned about cost and technical considerations, while two respondents (29%) initially thought the offer was a scam: one said, “My main thing was, to be honest, I was scratching my head if it was too good to be true. I was suspicious; there are so many scams. My biggest concern [was that] I just wasn’t quite sure what was actually going on. It’s quite a good deal to get that kind of equipment.”

Respondents’ cost considerations included not knowing how much more money they would pay by switching to a heat pump, as well as how much lower their energy bill would be and how much less energy they would use. Three respondents also expressed concerns about how reliable the heat pumps would be during the winter. The following quote exemplifies this sentiment and demonstrates how this hesitancy is related to a lack of knowledge about CCHPs: “…Without knowing about the technology, we were a little concerned…about how well would the systems work in the really cold weather.”

When asked what motivated them to install their heat pump, respondents reported several motivations, mainly saving energy and the free installation, followed by the fact that the cost was largely if not completely covered by Consumers Energy (Figure 24).

Figure 24. Respondent Motivations to Install Heat Pumps



Source: Heat Pump Commercial Interview Guide Question C4. "What motivated you to agree to install the heat pump?" (n=7; multiple responses allowed)

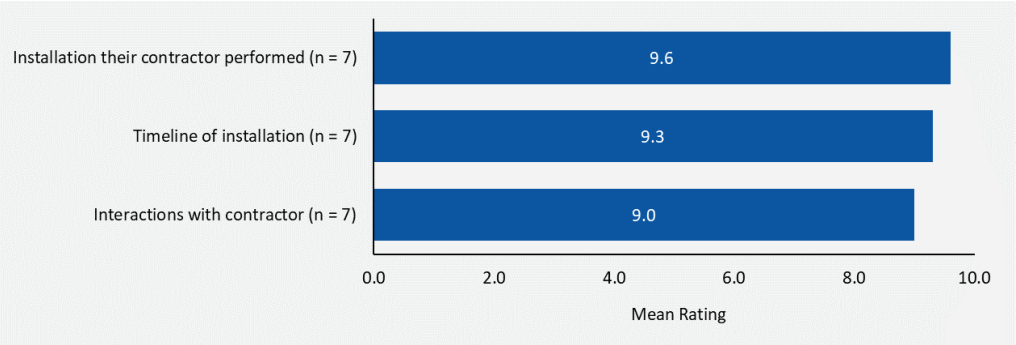
Installation Experiences

The Evaluation team also asked respondents about their experiences with finding a contractor and with having the heat pump installed. All respondents reported that it was easy to find a contractor, and none asked for multiple bids. About half of respondents (43%; n=3) preferred to use their own contractor and one respondent (14%) asked a friend who had also participated in the initiative for their contact. The other three respondents (43%) relied on contractor contacts provided by Consumers Energy: two chose a contractor they were familiar with from the list (and, as mentioned previously, Consumers Energy tailored this list to include trade partners they knew had experience with heat pumps). These findings indicate that the initiative resources for finding a contractor were effective.

Overall, respondents reported having a positive experience with their contractor, with 86% (n=6) saying they would use the same contractor again. All the respondents also reported that the contractors they worked with appeared to be knowledgeable about heat pumps, and 57% (n=4) said the contractor was *very knowledgeable*: "Extremely [knowledgeable] and very helpful and explained it all to me very well… They were fast, efficient, and did exactly what they were going to do in the time they said they were going to do it. They did a great job."

Average satisfaction with contractor interactions was a 9 on 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding* (as shown in Figure 25). Though respondents were generally satisfied with their contractors, two of the seven respondents (29%) expressed some dissatisfaction. One of these respondents specified that the contractor should have been more communicative about the project schedule and timeline but said they would still hire the contractor again because they would not know who else to hire. The other respondent was less satisfied with their interactions with the contractor and were not sure they would hire them again.

Figure 25. Installation Experiences Satisfaction Averages



Source: Heat Pump Commercial Interview Guide Questions G1a, G1b, and G1d. Please see *Appendix F* for specific question wording.

Respondents were also satisfied with the timeline of their installation. While about half of respondents (57%; n=4) reported some delay with their project timeline, it did not impact their overall satisfaction. However, some reported that if the installation had occurred during a time when they needed their heating or cooling, they would have been more dissatisfied. Heating or cooling needs were not pressing since these customers either had working equipment or their installation was completed in the shoulder season, as evident by the following statements:

- "It might have been different if we didn't have heat or air and every day was a struggle, but it was early spring… so it wasn't an issue, so we weren't pressed to hurry up and get this into service."
- "I'm glad they didn't do it in the winter, because then I would have been irritated [with the delayed project timeline]."

Most of the heat pump installations went smoothly, with respondents rating their satisfaction with the installation process as an average of 9.6 out of 10, as shown in Figure 25. When asked if there were any challenges with installing their heat pump, only two respondents reported some minor challenges related to the equipment not functioning properly at first and unforeseen installation issues. All respondents said that they received a new thermostat as part of their CCHP installation, and about half (43%; n=3) required new duct work. Slightly more than half of respondents (57%; n=4) reported that they have a back-up heating system in addition to the CCHP system. Of those four, two kept their old heating and cooling equipment, one just kept their old back-up heating, and one installed a new propane furnace as a back-up.

Experiences Using Heat Pumps

Due to the timing of this initiative and the research effort, respondents had primarily used their heat pump during the summer months and had used only the cooling function; however, some respondents (71%; n=5) reported that the heating function had come on during colder mornings in September or said they had been able to use the heat briefly in early spring. In general, respondents were very satisfied with their new heat pump and its operation, with an average satisfaction rating of 9.3 out of 10. While respondents were already generally satisfied with the equipment, a few customers noted being hesitant

to give the heat pump a higher rating until after using the heating function more consistently in colder weather. The Evaluation team conducted follow up interviews with Small Commercial initiative participants as part of on-site impact evaluations completed following the 2021/2022 winter heating season to assess participant experiences with the heat pumps in cold weather. [17]

Despite high satisfaction with heat pump performance, almost half of respondents (43%; n=3) reported some minor issues with their heat pumps, including not cooling down to the expected temperature and two issues with the installation that required a contractor to fix. The biggest challenge customers reported was needing to learn how to use their new smart thermostat; this finding was echoed in the winter heating impact analysis, which revealed that some customers would benefit from additional training or support to optimize heat pump controls and settings to maximize savings. These findings suggests that customers easily adapted to their new technology but could use some higher touch support during the first few weeks or months after installation to confirm that all the equipment is performing well and that the customer knows how to use the equipment properly.

Initiative Experiences and Satisfaction

When asked about their overall initiative experience, most respondents said they were *very satisfied* with their participation in the initiative. Most respondents (86%, n=6) had initially learned about the initiative offering from Consumers Energy staff and all seven reported that they had received excellent support throughout their participation. While respondent motivations for deciding to participate in the initiative included the fact that the equipment and installation were free, the support and persistence from Consumers Energy staff was also a motivating factor.

> "Just the willingness that they had to do this for just a small [facility] was huge […] People don't just give stuff away, and [a new heating system] was definitely something that was needed, and we would have had to purchase it in the future."
>
> -Respondent

Respondents' overall satisfaction with the pilot was an average of 9.9 out of 10, and 86% of respondents (n=6) *strongly agreed* that Consumers Energy made it easy to participate in the initiative. When asked if they were likely to recommend Consumers Energy to a friend or colleague if they had a choice in energy providers, most respondents (71%; n=5) said they were extremely likely to do so. The two respondents who gave lower ratings said that it was only because their utility is not something they really think or talk about. One satisfied respondent compared Consumers Energy to the utility that provides electricity at their home: "I've always had great service with Consumers [Energy]. I've had less outages and …anything I need for my business, I'm able to get immediate responses."

[17] TRC. 2022. C&I 2021 Cold Climate Heat Pump Pilot Impact Evaluation Memo.

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Appendix A. Survey and Interview Methodology and Details

This appendix provides survey and interview details and methodologies by initiative or stakeholder.

Contractor Interviews

Consumers Energy provided the Evaluation team with a sample of 177 contractors who had engaged with Consumers Energy HVAC energy waste reduction offerings at some point, but who had not participated in the CCHP Initiatives. The sample did not include any information regarding the number or type of projects completed by the contractor, so the Evaluation team was unable to stratify the sample in any meaningful way. As such, recruitment of contractors proceeded randomly until research quotas were satisfied. We interviewed a total of 11 contractors for this research.

Table A-1 includes contractors' company information such as type, number of projects per year, and products offered.

Table A-1. Interviewed Contractor List

Company Location	Customer Base	Number of Projects/Year	Average Heat Pump Installation/Year
Ada	Primarily residential, more high-end homes	~100	<5 ducted systems >20 mini-splits
Allen Park	Residential multifamily, some single family, very little commercial	1,000–1,500	75 since last fall
Allendale	Data not collected	Data not collected	Data not collected
Benzonia	90% to 95% residential, lots of big homes on shore of Lake Michigan used as seasonal residences; a little bit of multifamily, a little low income	200 installs	20–30
Dearborn Heights	Mostly residential, some multifamily	100	3 last year
Jackson	50% residential, 50% commercial	200–225	6–8 ducted systems >50 mini-splits
Livonia	Primarily (75% or more) income-qualified multifamily, with client that is the largest affordable housing provider in Michigan	5–10 projects per year 100–300 pieces of equipment	10–20 mini-splits per year (primarily server rooms and elevator machine rooms)
Okemos	60% residential and 40% commercial, lots in the city, also lots of dual-fuel applications with propane and lots of air-to-air and geothermal projects	~1,000	~100 in 2020, 80% air-to-air 24 mini-splits in the past year
Parma	Residential and some multifamily (very little commercial)	150–200 pieces of equipment	<10
Sparta	75% residential, commercial is mostly service maintenance, with a rare design/build	~100	12–15 per year for ASHPs and mini-splits.
Warren	50% residential and 50% commercial	200	<5

Distributor and Manufacturer Interviews

The Evaluation team interviewed five distributors and two manufacturers involved in the production and distribution of CCHPs (including mini-split heat pumps) in Michigan. We fielded the interviews via telephone, and each took 30 to 45 minutes to complete. The team recorded and transcribed each interview to assist with our analysis. To motivate manufacturers and distributors to participate, we offered a $75 incentive to each respondent in the form of an Amazon, Target, or Meijer gift card or a donation to a local United Way.

Sampling

For this effort, the Evaluation team specifically targeted manufacturers who have supplied equipment for Consumers Energy programs and associated distributors in Michigan that supply CCHPs produced by these manufacturers. The list of manufacturers and distributors interviewed is shown in Table A-2.

Table A-2. Interviewed Distributor and Manufacturer List

Company Type	Role of Interviewee	Primary Brands Offered	Primary Types Offered	States/Regions Served
Manufacturer	Manager, Utility & Efficiency Programs	(Confidential)	Mini-split	Central U.S.
Manufacturer	Regional Representative	(Confidential)	Mini-split	MI, OH, PA, WV
Distributor	President	Robur	Absorption	MI, OH, IN
Distributor	Director of HVAC Services	Mitsubishi, Rheem, Trane	Mini-split	MI, OH, Eastern U.S.
Distributor	Territory Manager	Trane, Mitsubishi	Mini-split, unitary	MI
Distributor	Regional Sales Manager	LG, Rheem, Bosch	Mini-split, unitary	MI, OH, IN, PA, WV
Distributor	Owner	Daikin, Amana	Mini-split, unitary	MI, WI, IL, IN, OH, PA

The team sampled distributors from a contact list provided by Consumers Energy staff as well as from internet searches for distributors associated with key manufacturers. Additionally, the Evaluation team asked for referrals for distributors during interviews with contractors. We targeted distributors such that representation across manufacturers was roughly equal (ensuring that interviewed distributors do not represent one manufacturer more than another).

Recruiting

The Evaluation team reached out to manufacturers and distributors by phone to schedule interviews. During phone recruitment, we explained the research and provided an Evaluation team contact person so the organization could reach out if they had additional questions or were interested in scheduling an interview. The team primarily used email to recruit referrals, which similarly included an explanation of the research and a request for scheduling an interview.

Profile of Distributors and Manufacturers

Table A-2 above shows respondent information including company type, the role of the interviewee at the company, primary brands offered, types of CCHPs offered, and regions served. Most interviewees represented mini-split CCHP technology and were responsible for operations in several states.

Residential Market Rate Participant Surveys

The Evaluation team sent a survey invitation to the census of 29 Residential Market Rate pilot participants in November 2021. The email survey invitation included a $15 incentive for taking the survey. The Evaluation team sent two reminder emails; after one week and after two weeks. Nine of the 29 participants completed the survey, for a 31% response rate: with such a small sample size, the results should be interpreted with caution and only viewed as directional indications (not intended to be analyzed with statistical confidence).

Income Qualified Multifamily Property Manager and Owner Interviews

The Evaluation team conducted in-depth telephone interviews with three site contacts (a construction manager, a resident manager, and an owner) in November 2021. Each interview lasted approximate 30 minutes. We targeted owners and managers of income-qualified multifamily properties who had participated in the Consumers Energy Income Qualified Multifamily initiative. Franklin Energy provided PMO contact information, including email address and phone numbers, for Evaluation team outreach and recruitment.

The Evaluation team initially distributed emails to six property site contacts and attempted phone recruitment for the seventh due to a missing email address. Though the team made three email attempts, the emails did not result in any successful recruitment for the interviews. The Evaluation team then pivoted to making recruitment calls from Monday through Friday, mid-morning to early evening, calling each number a maximum of five times.

With an interview target for a census (seven) of participating PMOs, the actual number of three interviewed PMOs was consistent with expectations, even with an increased incentive of $150 to make the interview more attractive for potential participants.

Income Qualified Single Family and Multifamily Participant Surveys

The Evaluation team collected feedback from 32 multifamily tenant surveys in November 2021. The email survey invitation included a $15 incentive for taking the online survey. We targeted tenants of income-qualified multifamily properties who had participated in the Consumers Energy heat pump offering. The Evaluation team did not have access to participating tenant contact information, so we attempted to identify tenants through two distinct efforts. First, the team relied on existing income-qualified tenant records to match CCHP properties based on physical address. Using this approach, the team identified 46 potential income-qualified multifamily tenants to recruit. Second, during the team's interviews with multifamily PMOs, we asked and all three PMOs if they were willing to distribute the survey recruitment email to their tenants. This second approach resulted in the potential for 90 additional tenant respondents, though the Evaluation team is unsure of the final count of emails distributed by the PMOs.

The Evaluation team solely relied on email distribution to recruit tenants for the online-only survey. Though the team made three email attempts for the address-matched income-qualified tenant group, the emails combined with the PMO email recruitment effort resulted in 32 successful recruitments for the surveys, for a response rate of 24% (32 of 136).

Small Commercial Participant Interviews

The Evaluation team conducted in-depth telephone interviews with seven business owners and decision-makers in September and October 2021. Each interview lasted approximately 30 to 45 minutes and we offered respondents a $75 gift card for their time. We targeted owners and decision-makers of small commercial and industrial facilities (<20,000 square feet) who had participated in the Consumers Energy Small Commercial initiative offering. Consumers Energy provided these decision-makers' contact information, including email address and phone numbers, for Evaluation team outreach and recruitment. The interview guide was reviewed and approved by Consumers Energy staff to ensure that questions were consistent with their expectations and reflected the issues of interest to Consumers Energy.

The Evaluation team recruited customers via email and phone. Due to the small sample size of nine participants, we attempted to recruit the entire sample with a minimum goal of five completes. The Evaluation team was able to recruit seven of the nine participants, with a response rate of 78%. An eighth participant was interested in participating but their heat pump had not been installed yet, so they were not able to answer questions about the full experience. The ninth participant was unreachable after a total of five contact attempts via email and voicemail.

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Appendix B. Impact Analysis Methodology and Details

This appendix provides the methodology and details related to the Residential Market Rate pilot engineering analysis and the Income Qualified Multifamily initiative billing analysis.

Market Rate Engineering Methodology

The Evaluation team conducted an engineering analysis of the impacts from the Residential Market Rate pilot and relied on MEMD assumptions and information we had collected on customer data such as such as home vintage, presence of central cooling, installed system COP at 5°F, rated HSPF and SEER, tonnage, and other data. The Evaluation team relied on the MEMD weighting tool, which generates single measure outputs based on home vintage, climate zone, sizing, and efficiency levels.

The MEMD building simulation data provided end-use level consumption details broken out by the seven Michigan climate zones (Alpena, Detroit, Lansing, Muskegon, Saginaw, Sault Ste. Marie, and Traverse City) and three building vintages (old, average, and new). The Evaluation team used the MEMD building simulation end-use consumptions for ASHP heating, ASHP electric resistance back-up heating, and ASHP cooling to calculate pre– and post–CCHP equipment consumption on a per-ton basis. We then adjusted these end-use consumptions using COP from ASHP federal standard HSPF and SEER values to reflect site-specific equipment. We used several types of CCHP-collected site data in the analysis:

- Home vintage
- Presence of central AC
- Home heating fuel type
- Home heating equipment type
- Premise zip code
- CCHP details: quantity, COP at 5°F, HSPF, SEER, and tons

Since existing space heating equipment data collection was limited to fuel type, the team assumed that existing equipment represents federal standard equipment (in AFUE) and represents a 50/50 average of boilers and furnaces, if applicable. The Evaluation team created this split because the data field for system type collected was either “Furnace/Boiler” or “Resistance.” The difference in federal standard efficiency is minimal: 0.8 for furnaces and 0.82 for boilers. Therefore, the team used 0.81 AFUE.

We also assumed that existing central cooling equipment represents the federal standard SEER value. For homes without central cooling, we assumed that a portion of homes use room or window AC units to provide a portion of cooling, and we based this portion of homes on *2015 Residential Energy Consumption Survey*[18] data for the East North Central census division. The Evaluation team used data

[18] U.S. Energy Information Administration Residential Energy Consumption Survey 2015 Data Website: https://www.eia.gov/consumption/residential/data/2015/

from the Consumers Energy 2021 *Electric Energy Waste Reduction Potential Study*[19] to develop a ratio of room AC tonnage for single family homes when compared to a central system (since the room AC unit likely did not provide cooling load equivalent to the CCHP system). Like with central ACs, we assumed the room AC efficiency to represent the federal standard EER value.

Since no sizing information was collected on the sites about the existing HVAC systems, the Evaluation team assumed equivalent kBtu per hour heating or cooling tonnage as the CCHP, except for existing room AC sizing (for which we made an adjustment). Therefore, results only reflect offset heating and cooling load by the CCHP, and not total household heating and cooling load.

We used two data points to map MEMD 2019 data to the site-specific data: "Approximate House Age" and "Premise Zip." The household age was a one-to-one match with MEMD vintages, and therefore was a simple mapping lookup. The Evaluation team mapped the zip codes nearest to the available MEMD weather station based on distance and engineering judgment for weather impacts. With these two site-specific data points—vintage and zip code—we were able to map the MEMD 2019 building simulation consumptions to each specific site.

To adjust the MEMD 2019 ASHP end-use consumptions to reflect the existing equipment on a per ton basis, the team applied COP adjustments using the federal standard definitions outlined above. To adjust the MEMD 2019 ASHP end-use consumptions to reflect the CCHP equipment, we performed a more detailed analysis (as additional equipment data was available). Using typical meteorological year version 3 (TMY3) 8760 hourly data for each MEMD modeled reference city, we performed hourly bin analysis to determine hours based on temperature bins in 5°F buckets. Assuming the HSPF value reflected performance at 47°F, the team developed a linear relationship using the COP at 5°F system performance data. We capped this linear relationship during cold temperatures to not be less than 1 COP, representing 100% electric resistance performance. Using the hourly bin analysis data by 5°F buckets and assuming CCHP heating did not occur above 65°F, the Evaluation team developed a weighted average CCHP HSPF efficiency to represent annual heating performance of the CCHP specific to the unit installed. We then used the weighted average CCHP HSPF and SEER values to adjust MEMD 2019 ASHP end-use consumptions to reflect CCHP performance on a per-ton basis. In order to represent total heating and cooling load, we multiplied the CCHP installed tonnage by the pre/post heating and cooling loads per ton.

The Evaluation team relied on Consumers Energy 2021 residential natural gas and electric marginal rates (per kilowatt-hour and per therm), which include all surcharges for single-family customers. The team used previously developed load shapes to reflect equipment usage during peak and non-peak periods for the electric bill impacts. We created annual electric fuel costs by applying each specific equipment type's consumption load shape to the peak and off-peak rates. For fuel oil and propane costs, the

[19] 2021 Energy Waste Reduction Electric Potential Study Report: https://cadmus.sharepoint.com/sites/collaboration/6409-P01/ces/Shared%20Documents/Final%20Reports/2021/Electric%20Potential%20Study/2021%20Energy%20Waste%20Reduction%20Electric%20Potential%20Study%20Report%20FINAL%202021.06.10.pdf

Evaluation team used the latest Michigan monthly data from U.S. Department of Energy resources. These fuel costs utilized in the impact analysis are shown below in Table B-1.

Table B-1. Market Rate Fuel Costs Utilized in Impact Analysis

Fuel Type	Cost
AC_Central Loadshape - Electricity with Surcharge	$0.18
AC_WallWindow Loadshape - Electricity with Surcharge	$0.18
ASHP Loadshape - Electricity with Surcharge	$0.17
ZONAL_ER_HEAT Loadshape - Electricity with Surcharge	$0.16
AC Central Load Shape - Electricity with Surcharge	$0.18 per kWh / $52.48 per MMBtu
AC Wall Window Load Shape - Electricity with Surcharge	$0.18 per kWh / $52.19 per MMBtu
ASHP Load Shape - Electricity with Surcharge	$0.17 per kWh / $48.57 per MMBtu
Zonal Heat Load Shape - Electricity with Surcharge	$0.16 per kWh / $48.18 per MMBtu
Propane	$2.44 per gallon / $26.71 per MMBtu
Fuel Oil	$3.10 per gallon / $22.56 per MMBtu
Natural Gas	$7.91 per thousand cubic feet / $7.62 per MMBtu

Sources: U.S. Energy Information Administration. Accessed on January 14, 2022. Heating Oil and Propane Update https://eia.gov/petroleum/heatingoilpropane/#itn-tabs-1
Electric and natural gas rates used from Consumers Energy.

Multifamily Billing Analysis Methodology

To estimate electric energy usage changes within the Income Qualified Multifamily initiative projects, the Evaluation team designed and conducted a statistical billing analysis. The team relied on historical advanced metering infrastructure (AMI) interval data to estimate facility-wide and per-tenant-unit savings associated with CCHP installations using the Princeton Scorekeeping Method. The team incorporated TMY3 data to normalize usage and control for weather. We also included a nonparticipant comparison group, selected from other income-qualified electrically heated multifamily nonparticipants to control for the impacts of nonprogrammatic factors (such as changes in economic conditions including COVID-19–related behavior changes).

Data Sources

The Evaluation team requested and compiled participant and household data for the CCHP billing analysis from several sources:

- ***Heat pump initiative tracking data.*** The team received initiative tracking data from the implementation contractor to identify CCHP properties. These initiative tracking data included all participants from March 2020 to December 2020, including property name, participation dates, building square footage, and heat pump efficiency and capacity ratings. The tracking data did not include specific tenant unit addresses or the specific account information connected with each tenant.
- ***Multifamily composite database.*** The team developed a multifamily database to identify multifamily properties based on property size for prior 2020 evaluation research, which we used to identify all unique addresses (and all accounts associated with each property), including tenant units.

- ***Electric AMI data.*** Consumers Energy provided electric AMI data for all properties that had identifiable account data. This included meter read dates and times and all kilowatt-hour usage, by account, between June 2019 and September 2021.
- ***Michigan weather data.*** The team collected average hourly temperatures from June 2019 through September 2021 for four weather stations corresponding to the nearest monitoring station locations associated with CCHP participants. We matched hourly heating degree hours (HDHs) and cooling degree hours (CDHs) to AMI data read dates and times, and compiled hourly TMY3 15-year normal weather averages from 1991 through 2005 from the National Oceanic and Atmospheric Administration to assess energy usage under normal weather conditions.

Data Processing

The Evaluation team conducted several data processing steps to review, validate, and transform the raw AMI and tracking data into an analysis dataset:

- Imported and cleaned the tracking, AMI, and weather station datasets into Statistical Analysis System software
- Merged tracking and AMI datasets using account ID
- Filled in missing or zero AMI data readings with averages based on similar day-types or as the average of the previous and following hours
- Checked the hourly AMI histories for problems such as vacancies, outliers, and too many missing/interpolated readings
- Mapped each property to the nearest weather station using the property zip code
- Used hourly temperatures to determine variable base HDHs and CDHs for each station
- Merged the HDHs and CDHs onto the AMI and tracking data, using respective dates and times for each account
- Matched TMY3 HDHs and CDHs from the nearest station to weather-normalize the AMI data

Participant and Nonparticipant Groups

For the AMI analysis, the Evaluation team assigned properties into participant and nonparticipant groups. To be selected for the participant group, all multifamily heat pump properties had to have a continuous nine-month period of available usage data both before and after their participation in the pilot. The team used a rolling specification to assign pre- and post-periods, identifying a range of months around the installation period for each participant. Starting with a census of participants from the March through December 2020 period (initially seven properties), the Evaluation team identified a final participant group for analysis (after screening for participants who had at least nine months of pre-period and post-period billing data). We conducted account-level reviews of pre- and post-period usage for all individual participants to identify anomalies (periods of vacancies or other anomalies) that could bias the results. The team also applied additional screening criteria, described in detail in the *Data Screening and Model Attrition* section.

The team used a comparison group of nonparticipants to account for exogenous factors that may have occurred coincident with heat pump initiative activities. These factors can include macroeconomic effects, COVID-related behavior or occupancy changes, or other interactions that may have affected energy usage outside the heat pump influence. The Evaluation team identified comparison groups using customers who we had identified as living in income-qualified electrically heated multifamily properties. After creating the eligible group of nonparticipants, we further refined the nonparticipant group by matching each property to a participant property based on pre-installation usage. This assisted us in creating groups with baseline usage profiles as similar as possible to those of participants.

Disaggregation

Consumers Energy had the Evaluation team focus the heat pump analysis on electric-heated properties to create savings associated with reducing electric heating and cooling loads. Because of the focus on electric heating and cooling loads, the Evaluation team disaggregated the billing data to isolate the weather-sensitive electric heating and cooling usage from overall annual electric usage (which may include water heating, cooking, plug load, and lighting usage). First, we estimated weather-normalization models for each customer in the pre- and post-installation periods using actual observed weather data. Then we estimated the weather-sensitive components of electric usage using TMY3 data. Finally, we estimated the heating- and cooling-related components of usage.

Data Screening and Model Attrition

Data anomalies, outliers, missing data points, incomplete records, and other data issues all introduce potential bias into a billing analysis. The Evaluation team used several rules to flag and then remove accounts that failed to meet certain conditions:

- ***Must have sufficient pre- and post-installation billing data for analysis.*** All accounts had to contain a minimum of nine months of pre- and post-installation usage data.
- ***Must have a pre- and post-installation change within 70%.*** All accounts showing post-installation usage changes of up to 70% of pre-installation usage were retained in the analysis.
- Must not be an outlier or vacancy. The Evaluation team performed account-level reviews of pre- and post-installation period usage for all individual participants and removed anomalies (such as periods of vacancies) that could bias the savings results. We also removed units that participated in another energy-efficiency program from the analysis, as we could not determine which project created the observed savings.

The data screening resulted in a final analysis sample of three unique participant properties representing 77 tenant units. This corresponds to just under half (43%) of the original participating properties. As shown in Table B-2, the largest source of attrition for the billing analysis of participants originated from removing vacancies from the analysis, primarily because the billing data was only available for accounts that were active at the time of the request. Many of the accounts that were currently active did not have the necessary historical usage data at the apartment unit level to be included in the analysis. For the nonparticipant group, the single largest source of attrition resulted from units that did not show an electric heating signature.

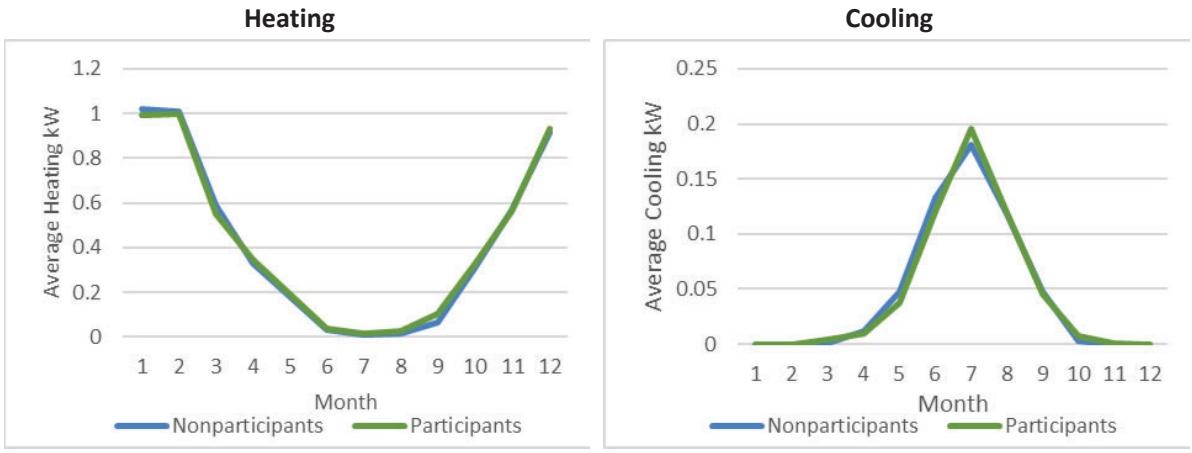
Table B-2. Income Qualified Multifamily Heat Pump Billing Analysis Summary Attrition

Screen	Participants	Nonparticipants
Initial Requested Sample	**97**	**2,329**
AMI Data Available	96	2,308
Sufficient Pre-Post Data	94	2,192
Removed Outliers/Vacancies	84	1,733
Matched Nonparticipant Property Type to Participant Property Type (such as removed high rise and mobile homes)	84	1,583
Determined that Dwelling Used Electric Heating	84	145
Passed Pre-Post Hourly PRISM Models/Hourly Prediction	84	132
Change within 70%	77	119
Matched Usage to Participants	77	112
Final	**77**	**112**

Baseline Electric Energy Use

Baseline multifamily building electric usage—the whole-building electric usage before installing energy-efficiency upgrades—is a critical input to whole-building energy savings estimation for electric-heated properties. The Evaluation team, using hourly PRISM (Princeton Scorekeeping Method) weather normalization and energy load disaggregation models, estimated the annual and monthly heating and cooling loads for the Income Qualified Multifamily participating tenant units. Additionally, estimating baseline heating and cooling energy usage across both participating and nonparticipating tenant units allows for isolating initiative-induced impacts specific to heat pump installation. This is important, as it accounts for non-programmatic influences on energy use, controlling for occupancy changes, behavior changes, changes attributable to COVID-19, and any other non-programmatic changes. A summary of the monthly average heating and cooling loads (in average kilowatts) across the participants and nonparticipant groups is shown in Figure B-1. There is little discernable difference—and, more importantly, no statistically significant difference—between participants' and nonparticipants' monthly heating and cooling loads.

Figure B-1. Baseline (Pre-Installation) Annual Heating and Cooling Load



The Evaluation team, with access to tenant apartment electric usage, estimated an average weather-normalized pre-installation baseline tenant unit usage of 3,860 kWh. Table B-3 shows the breakdown of the heating, cooling, and annual baseline pre-period annual weather-sensitive usage (per tenant apartment). As expected, given that multifamily tenant units in the CCHP were electrically heated, heating electric energy use is the predominant component (approximately 94%) of annual weather-sensitive use in these units.

Table B-3. Participant Tenant Unit Pre-Period Baseline Electric Weather-Normalized Per-Unit Usage

Usage Type	Weather-Sensitive Annual Usage (kWh)	Heating Usage (kWh)	Cooling Usage (kWh)
Billing Analysis	3,860	3,626	234

Source: Evaluation team AMI billing analysis.

Assess Change in Energy Use

As the final step in the analysis, the Evaluation team estimated real world changes to energy use between pre-and-post-installation usage patterns for participants and nonparticipants. Energy savings are the difference between participants' and nonparticipants' energy usage between the pre- and post-installation periods.

Engineering Calibration and Validation

The Evaluation team benchmarked the billing analysis findings relative to values produced from a simplified heat pump engineering model and the initiative-claimed savings (the initiative relied on current MEMD savings estimates). The goal of benchmarking was to help frame the billing analysis findings and understand how close the changes to energy usage tracked with alternative sources. The Evaluation team compiled initiative tracking claimed savings from eTracker and normalized the savings at the tenant apartment unit level by using the total number of installed heat pumps, the claimed savings, and the total number of apartment units. The team relied on the heating load requirement (3,626 kWh), assumed a CCHP COP of 2.75, and entered this data into a simple algorithm expressing continued baseboard heating, CCHP heating, and total heating demand based on several different displacement scenarios (Table B-4).

Table B-4. Cold-Climate Heat Pump Simplified Engineering Estimate

DHP Heating Load Displacement	Baseboard kWh	CCHP with COP of 2.75 (kWh)	Savings (kWh)	Total kWh
100%	-	1,319	2,307	3,626
75%	907	989	1,731	3,626
50%	1,813	659	1,154	3,626
36%	2,319	475	832	3,626

Bill Savings Estimation

To estimate the bill savings attributable to the CCHPs installed in the multifamily tenant units, the Evaluation team estimated the bill savings occurring during the time-differentiated bill periods across the year. According to residential rate data, peak period rates occur in summer months, from May 1 through September 30, during weekdays from 2 p.m. to 7 p.m. The Evaluation team then estimated the savings occurring during the peak and off-peak periods. Table B-5 shows a summary of the seasonal peak and off-peak rates and savings.

Table B-5. Cold-Climate Heat Pump Bill Savings Calculations

Residential Rate	Residential Billing Rate ($)	Income Qualified Multifamily CCHP Savings Occurring During Each Period (kWh)	Bill Savings ($)
Summer Peak	$0.213	6.1	$1.30
Off-Peak	$0.164	889.9	$145.94
Total Bill Savings			**$147.24**

Electric Savings: Engineering Comparison

The Evaluation team developed a simplified engineering estimate to compare how the evaluated electric savings compared with anticipated savings from a CCHP and added the initiative-claimed savings based on MEMD measures. Table B-6 shows a comparison of Income Qualified Multifamily initiative savings from the billing analysis sample, two engineering estimates based on two different displacement scenarios, and the initiative MEMD claimed savings estimate. The billing analysis estimate showed lower realized savings relative to the engineering estimate (assuming 50% of the electric baseboard heating was displaced by the CCHPs) and the MEMD estimate. In order for the engineering estimate to match the billing savings estimate of 832 kWh of heating load savings, the CCHPs would need to displace just over one-third (36%) of the heating load, which therefore assumes that the legacy baseboard heating systems still account for the majority of heating load for the apartments. The continued use of baseboard heat is consistent with feedback from the tenant survey, in which tenants reported continued use of baseboard heat as their primary heating source.

Table B-6. Annual Per–Tenant Unit Cold-Climate Heat Pump Electric Weather-Sensitive Savings Estimates Comparison

Source	Weather-Sensitive Usage (kWh) (A)	Weather-Sensitive Savings (kWh) (B)	Savings versus Weather-Sensitive Usage (%) (B / A)
Billing Analysis	3,860 (Annual)	896	23.2%
Billing Analysis	3,626 (Heating)	832	22.9%
Engineering @ 50% Displacement [a]	3,626 (Heating)	1,154	31.8%
Engineering @ 36% Displacement [a]	3,626 (Heating)	832	22.9%
MEMD/Pilot Claimed Savings [b]	3,860 (Annual)	1,474	38.2%

[a] This is an engineering estimate based on the heating season only and derived from AMI billing analysis.

[b] This represents annual weather-sensitive usage from the AMI billing analysis.

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Appendix C. Consumers Energy Heat Pump Market Rate Customer Survey

Objectives	Research Questions	Question Number
Assess customer awareness and motivations to install heat pumps	Were participants aware of heat pumps prior to participating in the offering? How do customers learn about heat pumps? What are participants' motivations for installing a heat pump? What are important decision factors for installing a heat pump? How much rebate is required to motivate participation?	Section B
Assess participant installation experience	How did participants experience the installation? Are there opportunities to improve the installation experience?	D1–D3
Document participant perceptions of heat pumps, energy or cost savings, comfort levels, and satisfaction	What are participants' experiences with heating/cooling comfort? How satisfied are participants with the heat pumps and the offering? How satisfied are participants with Consumers Energy?	D4–D12, B1, B2
	What non-energy benefits did the offering generate (such as reduced bill impacts, enhanced comfort levels, and improved operational issues)?	D11
Document participant usage behavior and home characteristics	How do respondents manage energy use at the thermostat?	Section C
	What are participants' home characteristics?	Section E

Survey Overview: The Evaluation team administered an online survey to residential customers who received a new heat pump. Then the team sent an email with a link to the survey, followed by reminder emails to encourage households to complete the survey withing the desired timeframe. In addition, the Evaluation team offered participants a $15 Meijer or Amazon.com gift card for completing the survey.

Target Audience: Census of Residential Market Rate pilot participants who installed a new heat pump as part of the Consumers Energy heat pump offering.

Survey Introduction and Purpose

Welcome, thank you for taking a few minutes to provide feedback about your cooling and heating equipment. Your feedback is very important to us and will help us improve rebates and incentives for new products that help customers save energy. This survey should take about 10 minutes. Your responses are confidential and will be used for research purposes only.

Be sure to enter your name and address at the end of the survey to receive your $15 Meijer or Amazon gift card as our thanks.

Click on the Next and Back buttons at the bottom of each page to navigate through the survey.

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A. *Screener*

A1. Our records indicate that you received a rebate for a heat pump installed in your home. Is this correct?
1. Yes
2. No **[TERMINATE]**
98. Don't know **[TERMINATE]**

A2. Approximately how long have you lived in your current home?
1. Less than one year
2. One to three years
3. Over three years

A3. **[If A2=1]** Were you living in your current home when the heat pump was installed?
1. Yes
2. No **[TERMINATE]**

TERMINATION MESSAGE: This survey is for Consumers Energy customers who received a rebate for a heat pump through the heat pump rebate program and who were living in the home when the heat pump was installed. Thank you for your interest in participating in this survey.

B. *Current Company Metrics and Awareness*

We'd like to ask some questions about your opinions toward Consumers Energy.

B1. How likely would you be to recommend Consumers Energy to a friend or family member if you had a choice in energy providers?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

B2. Please describe in detail why you gave that rating. _____

With these next questions, we would like to know more about your experience with heat pumps.

B3. Were you familiar with heat pumps before deciding to purchase and install the heat pump?
1. Yes
2. No
98. Don't know

B4. **[DISPLAY IF B3=1]** Prior to participating in this offer, had you ever had a contractor recommend a heat pump?
1. Yes, I had a contractor recommend a heat pump
2. No, a contractor has never recommended a heat pump to me

B5. Before you participated in this offer, were you aware that Consumers Energy offered rebates for heat pumps?

1. Yes, I was aware of heat pump rebates
2. No, I was unaware of heat pump rebates

B6. How did you first learn about the heat pump rebate? Please select only one response. **[RANDOMIZE 1–6]**

1. Contractor recommendation
2. Consumers Energy website
3. Consumers Energy flyer or other marketing material
4. Friend, family, neighbor, or colleague
5. Email from Consumers Energy
6. Online search
7. Other (please specify)

98. Don't know

B7. What were the main reason(s) you decided to install a heat pump in your home? (Select up to three) **[RANDOMIZE 1–9]**

1. To reduce energy bills in the winter months
2. To reduce energy bills in the summer months
3. To distribute heating and cooling more evenly throughout the home
4. To add heating and/or cooling for a new or renovated space in the home
5. To replace a broken heating or cooling system
6. To reduce reliance on natural gas or delivered fuels
7. To add cooling (where there was not previously a whole-home system)
8. To take advantage of heat pump incentives (from Consumers Energy and/or my contractor)
9. To take advantage of electricity produced at my home by renewable sources (such as solar or wind)
10. Something else (please describe)

B8. Please rate the importance of the following items on your decision to install a heat pump. **[RANDOMIZE ITEMS]**

Items	Not at All Important 1	2	3	4	5	6	7	8	9	Extremely Important 10	Don't know
a. The amount of rebate from Consumers Energy (up to $1,000)	○	○	○	○	○	○	○	○	○	○	○
b. Recommendation from a contractor	○	○	○	○	○	○	○	○	○	○	○
c. Possible energy savings over the previous heating/cooling system	○	○	○	○	○	○	○	○	○	○	○

B9. Would you have installed a heat pump if Consumers Energy had not offered a heat pump rebate?
1. Yes (I would have installed a heat pump without a rebate)
2. No
98. Don't know

B10. **[IF B9>1]** Would you have installed a heat pump if the rebate had been one-quarter of the value you received (up to $250)?
1. Yes (I would have installed the heat pump with a $250 rebate)
2. No
98. Don't know

B11. **[IF B9>1]** Would you have installed a heat pump if the rebate had been half as much as the amount you received (up to $500)?
1. Yes (I would have installed the heat pump with a $500 rebate)
2. No
98. Don't know

C. *Thermostat Use*

Next, we have a few questions about how you typically use your thermostat to manage the level of comfort in your home.

C1. What type of thermostat do you have in your home? (Select one.)
1. **Non-programmable** thermostat (set temperature manually and it did not change automatically)
2. **Programmable** thermostat with **set-backs programmed** (thermostat set to automatically change temperature at specific times)
3. **Programmable** thermostat—**not programmed** (thermostat has programming capability, but these were not used.)
4. **Basic networked or Wi-Fi–enabled** thermostat (had remote control, but not occupancy sensing or learning features)
5. **Smart learning** thermostat that includes advanced features such as occupancy sensing and schedule learning (examples include Nest, Ecobee, Honeywell Lyric, and Emerson Sensi)
98. Don't know

C2. Who in your household tends to monitor and adjust your thermostat?
1. I mostly monitor and adjust my home thermostat
2. Everyone in my household monitors and adjusts my home thermostat
3. Other members of my household typically monitor and adjust my home thermostat

C3. How did your household **most frequently** manage your thermostat to control the temperature in your home this summer? (Select one)
1. Keep it at a constant temperature
2. Manually adjust the temperature as needed
3. Create customized/programmed settings to automatically change temperatures at different times of the day
4. Allow the smart thermostat to manage the temperature by learning my preferences and/or detecting when home or away
5. Other (please describe)
98. Don't know

C4. Your heat pump offers the ability to use heating and cooling schedules. Did the installation technician setup your heat pump on a heating and cooling schedule?
1. Yes, the installer set up a heating and cooling schedule
2. No, the installer did not set up a heating and cooling schedule
98. Don't know

C5. **[IF C4=1]** Are you still using this heating and cooling schedule?
1. Yes, I have kept the heating and cooling schedule
2. No, I (or someone in my household) turned off the heating and cooling schedule
3. No, I (or someone in my household) changed the heating and cooling schedule to my own
98. Don't know

C6. Have you been provided with instructions on how to set up and control your heating and cooling schedule on your heat pump?
1. Yes, I received instructions
2. No, I did not receive instructions
98. Don't know

D. *Installation and Usage Experience*

Next, we would like to know about your experience with the heat pump.

D1. Our records indicate that the heat pump was installed in your home around **[INSTALLATION-COMPLETE DATE]**. Were you present during the installation of the heat pump?
1. Yes
2. No

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D2. Using a rating scale from 1 to 10, where 1 is *unacceptable* and 10 is *outstanding*, how would you rate each of the following installation experiences with the heat pump offering?

Question	Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know / NA
Scheduling a time for installation	O	O	O	O	O	O	O	O	O	O	O
Staying informed about the installation	O	O	O	O	O	O	O	O	O	O	O
[If D1=1] Overall installation time	O	O	O	O	O	O	O	O	O	O	O
[If D1=1] The professionalism of the installation technician	O	O	O	O	O	O	O	O	O	O	O
Education and instructions provided to you about heat pump usage	O	O	O	O	O	O	O	O	O	O	O
Follow-up from the installation technician or Consumers Energy	O	O	O	O	O	O	O	O	O	O	O

D3. **[IF ANY QUESTION IN D2=6 OR LOWER]** If there was something unsatisfactory about the heat pump installation, please describe in detail why you gave that rating.

_____

D4. In general, how did the heat pump affect your home comfort? (Select all that apply)

1. My home is **just as comfortable** as it was previously
2. My home is **more comfortable** than it usually was
3. My home is uncomfortably warm
4. My home is uncomfortably cold
5. My home is **too humid**
6. My home is **too dry**
7. My home was more evenly heated and/or cooled prior to the installation
8. Something else (please describe)

D5. **[IF D1=1 AND COMPLETE DATE IS PRIOR TO APRIL 1, 2021]** How would you rate the heating comfort level provided by the heat pump during winter months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
O	O	O	O	O	O	O	O	O	O	O

[If D5<6] What concerns do you have about the heat pump's ability to heat to your comfort level?

_____

D6. How would you rate the cooling comfort level provided by the heat pump during summer months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
O	O	O	O	O	O	O	O	O	O	O

[If D7<6] What concerns do you have about the heat pump's ability to cool to your comfort level?

_____

D7. Taking everything into consideration, how would you rate your overall experience with the heat pump so far?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
O	O	O	O	O	O	O	O	O	O	O

D8. Based on your experiences with the heat pump so far, how likely would you be to recommend it to a friend?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

D9. Based on your experience so far, do you have any recommendations to improve the heat pump rebate offer? _____

98. Don't know

D10. Since the heat pump was installed, have you seen a lower-than-expected energy bill?

1. Yes
2. No
3. Too soon to tell
98. Don't know

D11. In addition to energy savings, if any, are there additional benefits you have experienced or observed from the installation of a heat pump? (Select all that apply) **[RANDOMIZE]**

1. Increased comfort
2. Lower utility bills
3. Improved appearance of my home
4. Improved air quality
5. Improved heating and cooling distribution (across sections of my home)
6. Less maintenance required

7. Improved ability to manage heating/cooling on a schedule
8. Fewer illnesses for household members
9. Other (please specify)
10. Too soon to know **[EXCLUSIVE OF OTHER RESPONSES]**
11. No other benefits **[EXCLUSIVE OF OTHER RESPONSES]**

98. Don't know **[EXCLUSIVE OF OTHER RESPONSES]**

D12. **[If D12=1 AND D11<10]** Considering that the heat pump offering provided both saved energy and some additional benefits to your home, please indicate which was the most important to you:

1. The energy savings
2. The other benefits previously identified
3. The energy savings are equal to the other benefits

98. Don't know

E. *Demographics*

Finally, we have a few questions about your home.

E1. How many people live in your household on a regular basis, year-round?

1. 1
2. 2
3. 3
4. 4
5. 5
6. More than 5

99. Prefer not to answer

E2. Approximately how many square feet of living space does your home have? Do not include the basement unless it is a space that you consider lived in.

1. Under 1,000 square feet
2. 1,000 to less than 1,500 square feet
3. 1,500 to less than 2,000 square feet
4. 2,000 to less than 2,500 square feet
5. 2,500 to less than 3,000 square feet
6. 3,000 to less than 4,000 square feet
7. 4,000 or more square feet

98. Don't know

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F. *Closing*

F1. On occasion, managers of the Consumers Energy programs may want to contact a customer to learn more about their participation experience. Please check here if you prefer not to be contacted by a program manager.
1. Do not contact me

F2. Do you have any recommendations for ways Consumers Energy can support you in helping you save energy?
1. Please describe_____

F3. To thank you for your time spent completing this survey, we would like to send you a $15 gift card to either Meijer or Amazon.com. Please choose which gift card you would like to receive.
1. $15 Meijer gift card
2. $15 Amazon.com gift card
3. Neither – I do not wish to receive a gift card

F4. **[IF F3=1 OR 2]** Please provide your name, address, and email to receive your gift card. This information will only be used to mail your gift card.
1. Name:_____
2. Address:_____
3. Address 2:_____
4. City:_____
5. State:_____
6. Zip:_____
7. Email**:** _____

Please click Next to submit the survey.

[END OF SURVEY MESSAGE] Those are all the questions we have at this time. Thank you for your participation in the Consumers Energy heat pump offer.

For more information on energy efficiency, here's where to find it:

- **Want Online Information about Our Other Energy-Efficiency Rebates and Programs?** For details of additional ways Consumers Energy may be able to help you make your home more energy efficient and help you manage your monthly energy bills, please visit us online at ConsumersEnergy.com/myhome.
- **Want to Speak to an Energy-Efficiency Advisor by Phone?** To talk to someone about additional rebates and programs, please contact one of our Energy Advisors at (888) 652-1237.

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Appendix D. Consumers Energy Heat Pump Property Owner and Manager Interview Guide

Research Questions

Objectives	Research Questions	Interview Section
Document participant installation experience	How well did the offering manage the user installation experience? Are there opportunities to improve the installation experience?	B1, B3
Document participant usage behavior and experience	How are tenants using and operating the heat pumps? Did customers retain secondary or supplemental heating equipment after the heat pump was installed?	B2, B4
Document awareness and perceptions of heat pumps	What is the current perception of heat pump technologies? Were participants aware of heat pumps prior to being approached by Consumers Energy or the contractor? What are the perceived energy benefits of heat pumps? What non-energy benefits did the offering generate (such as reduced bill impacts, enhanced comfort levels, or improved operational issues)?	C1–C4, E2–E5
Document participant decision-making around participating in the heat pump offering	What key factors affected participants' decisions to install a heat pump? What are the key barriers to adopting heat pumps?	D1–D4
Identify marketing and outreach best practices	How did the participant learn about the offering?	C3
	What are the most effective means of marketing heat pumps?	F1–F3
Assess satisfaction with the offering and with Consumers Energy	How satisfied are property owners and managers with the heat pump offering? How satisfied are tenants with the heat pumps and the offering? How satisfied are property owners and managers with Consumers Energy?	G1–G4

Target Audience: The target audience for these interviews was multifamily PMOs who participated in the CCHP initiatives. The Evaluation team attempted to interview a census of participating PMOs.

A. General Introduction

A1. To begin, please tell me about your multifamily properties.

1. How many unique multifamily properties do you own or manage?
2. How many of them are located in Michigan?
3. Do you own/manage only subsidized or income eligible housing or do you also own/manage market rate properties?

B. Installation and Usage Experience

B1. Please describe your experience, including any positive or negative elements, of the heat pump installation for each of the following installation components (please note if you are not aware of any of these elements):

1. Scheduling a time for the installation
2. Informing the tenants
3. Overall installation time
4. Professionalism of the installation technicians
5. Education and instructions provided to management about heat pump usage
6. Education and instructions provided to tenants about heat pump usage **[PROBE: WERE YOU INFORMED ABOUT PRIORITIZING HEAT PUMP USAGE OVER BASEBOARD HEATING?]**
7. Follow up

B2. Have you received any feedback from your tenants about the new heat pumps? **[PROBE: DO THE COMMENTS TEND TO BE POSITIVE, COMPLAINTS, OR QUESTIONS?]**

B3. Have you had any concerns or issues with the heat pumps installed in your property? **[PROBE: HAVE TENANTS COMPLAINED, DO MAINTENANCE STAFF HAVE ANY FEEDBACK ABOUT THEM?]**

B4. It is our understanding that the existing baseboard heating equipment was left in tenant apartments. Are you aware of whether tenants are continuing to use their baseboard heaters or if they rely mostly on the new heat pumps for heating?

1. Are you aware if the tenants received educational materials or training on the use of the heat pumps? **[PROBE: HAVE TENANTS SEEN THESE MATERIALS? HOW WERE THEY DISTRIBUTED? DO THEY FIND THE MATERIALS TO BE USEFUL?]**

C. Heat Pump Awareness and Perceptions

C1. Before participating in this heat pump offering, were you familiar with heat pumps?

C2. Prior to participating in this offering, had you ever had a contractor recommend heat pumps?

C3. Before you participated in this offering, were you aware that Consumers Energy offered rebates for heat pumps?

1. **[IF HEARD ABOUT OFFERING]** Where did you hear about the heat pump offering?
2. **[IF HEARD ABOUT OFFERING]** What were your immediate perceptions of the offering?

C4. Other than **[NAME OF PROPERTY IN THE HEAT PUMP OFFERING]**, do any of your properties currently have heat pumps installed for heating and cooling?

1. **[IF HAS HEAT PUMPS INSTALLED]** How many (if any) of the properties you own/manage use heat pumps? **[PROBE TO SEE IF THEY ARE IN MICHIGAN]**
2. For those properties, do residents typically retain secondary or supplemental heating equipment after the heat pump is installed? Please describe.

D. Motivators and Barriers

D1. What were the most important factors in your decision to participate in the heat pump offering? **[DO NOT READ OR PROMPT; SELECT ANY THAT ARE MENTIONED]**

1. Lower tenant utility costs
2. Lower owner utility costs
3. Improve the property appearance
4. Improve tenant comfort
5. Increase the property value
6. Replace old or broken equipment
7. Take advantage of low-cost/no-cost improvements
8. Reduce impact on the environment
9. Lower operating and maintenance costs
10. Improve property aesthetics
11. Improve health and safety
12. Satisfaction with previous Consumers Energy program experience
13. Turnkey and easy to participate
14. Other (Please specify)

98. Don't know

D2. Which of these factors was the most important to your decision? **[REPEAT THOSE MENTIONED IN PREVIOUS QUESTION TO ALLOW SELECTION FROM LIST]**

D3. What do you consider to be the primary barriers to adding heat pumps to other properties? **[DO NOT READ OR PROMPT; SELECT ANY THAT ARE MENTIONED]**

1. Overall upfront costs
2. Logistical effort required to deal with installation
3. Finding the right contractor
4. Getting management approval
5. Tenant disruption
6. Tenants' ability to use the equipment to reduce energy consumption
7. Other (Please specify)

98. Don't know

D4. Which of these factors is the most significant barrier to your decision? **[REPEAT THOSE MENTIONED IN PREVIOUS QUESTION TO ALLOW SELECTION FROM LIST]**

E. Savings and Benefits of Participation

E1. Do you or your tenants pay the electric utility bills?

E2. **[IF TENANTS PAY]** Have your tenants provided feedback about their bills since installation of the heat pumps? If so, please describe what this feedback has entailed.

E3. **[IF PROPERTY OWNER/MANAGER PAYS UTILITY BILLS]** Have you noticed any change in your utility bills since installation of the heat pumps? If so, please describe the change. **[PROBE: HAVE THERE BEEN ANY DIFFERENCES IN UTILITY BILL CHANGES BETWEEN WINTER HEATING AND SUMMER COOLING?]**

E4. In addition to energy savings, are there any other benefits that your property, your tenants, or property management have experienced from installing the heat pumps? **[DO NOT READ OR PROMPT; SELECT ANY THAT ARE MENTIONED]**

1. Lower maintenance costs
2. Improved operations
3. Increased property value
4. Decreased vacancy rates
5. Increased rental income
6. Increased net operating income
7. Increased tenant comfort
8. Decreased late or nonpayment of rent
9. Decreased tenant complaints
10. Improved property aesthetics
11. Health and safety improvements
12. Other (Please specify)
13. Too soon to tell
14. No other benefits

98. Don't know

E5. **[ASK IF E3=YES AND E4≠13, 14, OR 98]** Considering that the heat pump offering provided both energy savings and some other benefits to your property, please indicate which was the <u>most important</u> benefit:

1. The energy savings
2. The non-energy benefits (previously identified)
3. The energy savings benefits are equal to the non-energy benefits

98. Don't know

F. Outreach and Marketing

F1. What, in your opinion, could be done to increase the adoption of heat pumps in the multifamily market?

F2. What are the most effective ways to let other multifamily property owners and managers know about the benefits of heat pumps?

F3. What information would be helpful for other property managers and owners to become interested in heat pumps?

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G. Opinion of Heat Pump Offering and Consumers Energy

G1. Taking everything into consideration, how would you rate your overall experience with the multifamily heat pump offering, where 1 means *unacceptable* and 10 means *outstanding*?

Unacceptable 1	2	3	4	Average 5	6	7	8	9	Outstanding 10	Don't know
O	O	O	O	O	O	O	O	O	O	O

G2. Based on your experiences with the heat pump offering, how likely would you be to recommend the offering to a business colleague, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

G3. Based on your experiences with the heat pump offering, how likely would you be to recommend Consumers Energy to a business colleague if you had a choice in energy providers, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

G4. Based on your experience with the heat pump offering, how likely would you be to make similar improvements to some or all the properties you manage, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

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H. Wrap Up

H1. In what ways can Consumers Energy programs better help you manage your multifamily properties' energy use?

H2. Our research also includes a tenant survey to capture their experience and usage with the heat pumps, but we do not have tenant contact information to recruit them for this effort. Would you be interested in **[OPTION A]** securely sharing tenant emails with us so they can receive an email link to complete an online survey or **[OPTION B]** would you be willing to forward an email invitation to your tenants to complete the online survey? Tenants will receive a $15 gift card for their time. [**ENTER WILLINGNESS RESPONSE OPTION AND BE SURE TO REQUEST THE PMO EMAIL ADDRESS TO ENSURE EITHER OPTION CAN BE SHARED**]

Those are all the questions we have. Thank you very much for taking the time to assist us with this evaluation. Your contribution is a very important part of the process. We are planning to send you your choice of a $50 Amazon or Meijer card (if you choose Meijer, we will need your mailing address, as there is no e-card option). Please let us know your choice of card **[ENTER CARD CHOICE AND REQUEST EMAIL ADDRESS IF AMAZON OR MAILING ADDRESS IF MEIJER]**.

Look for your gift card in the mail in the next three weeks. If you have any questions about this survey or about your gift card, please call **[APEX STAFF]** at **[303-590-9888 Ext XXX]**. Thank you for your time.

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Appendix E. Consumers Energy Heat Pump Multifamily Tenant Survey Guide

Objectives	Research Questions	Question Number
Document participant awareness of heat pump	Are tenants aware of what a heat pump is? Were tenants aware of a heat pump installed for their apartment? Are tenants who were aware of the heat pump also aware that Consumers Energy funded it?	Section B
Document participant installation experience	How did the heat pump offering help Consumers Energy to manage the tenant installation experience? Are there opportunities to improve the installation experience?	D1–C3
Assess participant perceptions of heat pump impact on comfort levels and electricity bills	What perceptions do tenants have of heating and cooling comfort levels? What are the perceived energy benefits of heat pumps? What non-energy benefits did the offering generate (such as reduced bill impacts, enhanced comfort levels, and improved operational issues)?	C4–C11, D2–D4
Document participant usage behavior and experience	How are tenants using and operating the heat pumps? Are tenants continuing to use their baseboard heating?	C12–C18
Assess participant satisfaction with the offering and with Consumers Energy	How satisfied are tenants with the heat pumps offering? How satisfied are tenants with Consumers Energy?	E1–G3, A1, A2

Survey Overview: The Evaluation team administered a web-based survey with multifamily tenants who received a new heat pump. Then the team sent an email with a link to the survey to participants who could be matched to participating multifamily buildings and had an email address, followed by reminder emails to encourage households to complete the survey within the desired timeframe. In addition, the Evaluation team offered participants a $15 Meijer or Amazon.com gift card for completing the survey.

Target Audience: Census of individual tenant dwellings that could be matched to the multifamily building and had an email address. The Evaluation team had 75 emails associated with the multifamily properties by linking an income-qualified survey contact database with the Income Qualified Multifamily incentive properties. Assuming a 10% response rate, we hoped to receive approximately eight completed surveys.

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A. Current Company Metrics

First, we'd like to ask some questions about your opinions toward Consumers Energy.

Consumers Energy Count on Us®

A1. How likely would you be to recommend Consumers Energy to a friend or family member if you had a choice in energy providers?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

A2. Please describe in detail why you gave that rating. _____

B. Awareness

B1. Are you familiar with what a heat pump is?

1. Yes, I am familiar
2. No, I do not know what a heat pump is

[IF B1=2, PROVIDE EXPLANATION ABOUT HEAT PUMPS: HEAT PUMPS ARE EQUIPMENT THAT PROVIDES BOTH HEATING AND COOLING FOR HOMES.]

B2. Our records indicate that the apartment you currently occupy received a new heat pump. Are you aware of this?

1. Yes
2. No

B3. **[If B2=1]** Were you aware that Consumers Energy funded this project and made the heat pump technology available in your home?

1. Yes, I was aware of Consumers Energy involvement
2. No, I was unaware of Consumers Energy involvement

98. Don't know

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C. Installation and Usage Experience

Next, we would like to know about your experience with the heat pump.

[SHOW QUESTIONS D1 TO C3 IF COMPLETE DATE IS NOT EMPTY]

C1. Our records indicate that the heat pump was installed in your apartment around **[COMPLETE DATE]**. Were you present during the installation of the heat pump?

1. Yes, I was present during installation
2. No, I was not present during installation

C2. Using a rating scale from 1 to 10, where 1 is *unacceptable* and 10 is *outstanding*, how would you rate each of the following installation experiences with the heat pump offering?

Question	Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
Scheduling a time for installation	O	O	O	O	O	O	O	O	O	O	O
Staying informed about the installation	O	O	O	O	O	O	O	O	O	O	O
[IF C1=1] Overall installation time	O	O	O	O	O	O	O	O	O	O	O
[IF C1=1] The professionalism of the installation technician	O	O	O	O	O	O	O	O	O	O	O
Education and instructions provided about heat pump usage	O	O	O	O	O	O	O	O	O	O	O
Follow-up from the installation technician or Consumers Energy	O	O	O	O	O	O	O	O	O	O	O

C3. **[IF ANY QUESTION IN C2≥6]** If there was something unsatisfactory about the heat pump installation, please describe in detail why you gave that rating.

_____

C4. Approximately how long have you lived in your current apartment?

1. Less than six months
2. Between six months and one year
3. Over one year

C5. Were you living in your apartment last winter, before the heat pump was installed?

1. Yes
2. No

C6. **[IF C5=1]** How would you rate the heating comfort level provided by the heat pump during winter months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

C7. **[IF C6<7]** What concerns do you have about the heat pump's ability to heat to your comfort level? _____

C8. Were you living in your apartment last summer, before the heat pump was installed?

1. Yes
2. No

C9. **[IF C8=1]** How would you rate the cooling comfort level provided by the heat pump during summer months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

C10. **[IF C9<7]** What concerns do you have about the heat pump's ability to cool to your comfort level? _____

C11. In general, how did the heat pump affect your home comfort? (Select all that apply)

1. My home is **just as comfortable** as it was previously
2. My home is **more comfortable** than it usually was
3. My home is uncomfortably warm
4. My home is uncomfortably cold
5. My home is **too humid**
6. My home is **too dry**
7. My home was more evenly heated and/or cooled prior to the installation
8. Something else (please describe)

C12. Our records indicate that the existing baseboard heating equipment was left in all apartments where heat pumps were installed.
Which of the following best describes how you heated your apartment last winter?
[RANDOMIZE 1-3]

1. Mostly used baseboard heating
2. Relied evenly on the heat pump and baseboard heating
3. Mostly used the new heat pump

98. Don't know

C13. Your baseboard heating should have a thermostat that controls your home's heating.
What type of thermostat do you have in your home?

1. **Non-programmable** thermostat (set temperature manually and it did not change automatically)
2. **Programmable** thermostat with **set-backs programmed** (thermostat set to automatically change temperature at specific times)
3. **Programmable** thermostat—**not programmed** (thermostat has programming capability, but these were not used.)
4. **Basic networked or Wi-Fi–enabled** thermostat (had remote control, but not occupancy sensing or learning features)
5. **Smart learning** thermostat that includes advanced features such as occupancy sensing and schedule learning (examples include Nest, Ecobee, Honeywell Lyric, and Emerson Sensi)

98. Don't know

C14. Who in your household tends to monitor and adjust your thermostat associated with your baseboard heating?

1. I mostly monitor and adjust my home baseboard thermostat
2. Everyone in my household monitors and adjusts my home baseboard thermostat
3. Members of my household (other than me) typically monitor and adjust my home baseboard thermostat

C15. How did your household **most frequently** manage your baseboard thermostat to control the temperature in your home this summer?
1. Keep it at a constant temperature
2. Manually adjust the temperature as needed
3. Create customized/programmed settings to automatically change temperatures at different times of the day
4. Allow the smart thermostat to manage the temperature by learning my preferences and/or detecting when home or away
5. Other (please describe)
98. Don't know

C16. Your heat pump offers the ability to use heating and cooling schedules. Did the installation technician set up your heat pump on a heating and cooling schedule?
1. Yes, the installer set up a heating and cooling schedule
2. No, the installer did not set up a heating and cooling schedule
98. Don't know

C17. **[IF C16=1]** Are you still using this heating and cooling schedule?
1. Yes, I have kept the heating and cooling schedule
2. No, I (or someone in my household) turned off the heating and cooling schedule
3. No, I (or someone in my household) changed the heating and cooling schedule to my own
98. Don't know

C18. Have you been provided with instructions on how to set up and control your heating and cooling schedule on your heat pump?
1. Yes, I received instructions
2. No, I did not receive instructions
98. Don't know

D. Savings and Benefits of Participation

D1. How would you describe how your electric utility use is billed?
1. I receive a monthly electric utility bill directly from the utility for my usage
2. My landlord receives an electric utility bill for the whole building's usage
3. The electricity use for my unit is billed some other way (please describe)
4. I'm not sure how the electric utility use is billed

D2. **[IF E1=1]** Have you seen a lower-than-expected energy bill?
1. Yes
2. No
3. Too soon to tell
98. Don't know

D3. In addition to energy savings, if any, are there other benefits that you have experienced or observed from the installation of heat pumps? (Select all that apply) **[RANDOMIZE 1–8]**

1. Increased comfort
2. Lower utility bills
3. Decreased complaints about my apartment temperature
4. Improved air quality
5. Improved appearance of my apartment
6. Improved heating and cooling distribution (across sections of my home)
7. Fewer illnesses for household members
8. Improved ability to manage heating/cooling on a schedule
9. Other (Please specify)
10. Too soon to tell [EXCLUSIVE OF OTHER RESPONSES]
11. No other benefits [EXCLUSIVE OF OTHER RESPONSES]

98. Don't know [EXCLUSIVE OF OTHER RESPONSES]

D4. **[ASK IF D2=1 AND D10≠10, 11, OR 98]** Considering that the heat pump offering provided both saved energy and some additional benefits to your apartment, please indicate which was <u>most important</u> to you:

1. The energy savings
2. The other benefits previously identified
3. The energy savings are equal to the other benefits

98. Don't know

E. Opinion of Heat Pump Offering and Consumers Energy

E1. Taking everything into consideration, how would you rate your overall experience with the heat pump?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

E2. Based on your experiences with the heat pump, how likely would you be to recommend a heat pump to a friend?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already Did Recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

E3. Do you have any recommendations for ways Consumers Energy can further support you in saving energy?
1. Please describe_____

F. Closing

F1. On occasion, managers of the Consumers Energy programs may want to contact a customer to learn more about their participation experience. **Please check here if you prefer not to be contacted by a program manager.**
1. Do not contact me

F2. To thank you for your time spent completing this survey, we would like to send you a $15 gift card to either Meijer or Amazon.com. Please choose which gift card you would like to receive.
1. $15 Meijer gift card
2. $15 Amazon.com gift card
3. Neither – I do not wish to receive a gift card

F3. **[ASK IF F2=1 OR 2]** Please provide your name, address, and email to receive your gift card. This information will only be used to mail your gift card.
1. Name:_____
2. Address:_____
3. Address 2:_____
4. City:_____
5. State:_____
6. Zip:_____
7. Email**:** _____

Please click Next to submit the survey.

Those are all the questions we have at this time. Thank you for your participation in the Consumers Energy heat pump offer.

For more information on energy efficiency, here's where to find it:

- **Want Online Information about Our Other Energy-Efficiency Rebates and Programs?** For details of additional ways Consumers Energy may be able to help you make your home more energy efficient and help you manage your monthly energy bills, please visit us online at ConsumersEnergy.com/myhome.
- **Want to Speak to an Energy-Efficiency Advisor by Phone?** To talk to someone about additional rebates and programs, please contact one of our Energy Advisors at (888) 652-1237.

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Appendix F. Consumers Energy Heat Pump Commercial Interview Guide

Cold-Climate Heat Pump Participant Interview Research Objectives and Questions

Objectives	Research Questions	Interview Questions
Explore key factors in customer decision-making regarding heat pump installations	Were customers aware of heat pumps prior to the pilot outreach?	C1, C1a, C1b, C1c
	What were customers' perceptions of heat pumps prior to installation? What barriers did customers face when considering the installation of heat pumps?	C3
	What motivated customers to install heat pumps?	C5, C5a, C5b
	What technology would customers have installed without the initiative intervention and why?	C4, C4a
Explore customer experiences during the heat pump installation process	How did participants find their contractor who installed the equipment? How did participants perceive their contractors knowledge of heat pump technology and installation methods? How did participants perceive the length of time to purchase and install the heat pump and how long did that process take?	D1, D2, D4, D4a, D5
	What type of equipment did customers use prior to the heat pump? Did participants need to install new duct work, a new thermostat, and/or back-up systems for their heat pump?	D6, D7, D8, D9, D10
	Were participants satisfied with their contractors (including their interactions with their contractors and the contractors' performance), the installation process, and the timeline? Why or why not? Would they use the contractor again?	G1a, G1b, G1d, D3
Explore customer experiences using their heat pump	Does the heat pump provide the level of heating required for comfort and meeting customer needs?	E2, E2a
	Does the heat pump provide the level of cooling required for comfort and meeting customer needs?	E3, E3a
	Can customers operate the heat pump easily, including the remote controls? Do they need to change their habits in any way?	E1, E4, E4a, E5, E5a, E5b, E6
	How does the heat pump compare to prior equipment with regards to air quality?	E7, E7a
	How does the heat pump compare to prior equipment with regard to noise?	E8, E8a
	Are participants satisfied with their heat pump? Why or why not?	G1c
Explore customer experiences with the initiative offering	How did participants learn of the initiative opportunity?	C2
	Did participants interact with program staff? If so, what were their experiences?	F1, F1a, F1b
	Were participants satisfied with the pilot offering?	G1e
Identify opportunities to best support heat pump technology moving forward	Which aspects of the initiative offering were most helpful to customers (such as the staff support versus the financial incentive)?	F4
	What additional support, if any, did participants need to pursue the installation and use of their heat pump?	F2, F2a, F3, F3a, D4b

Survey Overview. The Evaluation team attempted to interview the full population of participating customers, with a goal to complete at least five interviews. The team included a $75 incentive to increase the likelihood of response. The Evaluation team sent advance emails to all respondents with available email addresses and followed up with phone calls as needed to schedule interviews. This email explained the research and provided a Consumers Energy and Evaluation team contact person if the respondent had additional questions or wanted to schedule an interview. For phone recruitment, the

team left a voicemail or receptionist message on the first attempt whenever possible, then used discretion to determine any additional messages left on subsequent attempts (with a maximum of five attempts to each contact).

A. Introduction

A1. First, can you tell about the work you do at **[BUSINESS NAME]**?

A2. And what is your role at the business? **[PROBE FOR ROLE AND RESPONSIBILITIES]**

B. Consumers Energy

Next, we'd like to ask you a few questions about your opinions toward Consumers Energy.

B1. How likely is it that you would recommend Consumers Energy to a friend or colleague if you had a choice in energy providers using a scale from 1 to 10, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

B2. Please describe why you gave that rating.

B3. To what extent do you agree that Consumers Energy made it easy to participate in the Cold-Climate Heat Pump Initiatives, using a scale from 1 to 5, where 1 means *strongly disagree* and 5 means *strongly agree*?

Strongly disagree 1	2	3	4	Strongly agree 5
O	O	O	O	O

C. Decision-Making

Next, I'd like to ask some questions about your decision to install a heat pump.

C1. Prior to Consumers Energy contacting you about the heat pump offering, how familiar were you with heat pump technology to heat and cool your facility?

1. **[IF AWARE, PROBE]** What were your perceptions of heat pumps?
2. **[IF AWARE, PROBE]** Had you heard anything about their performance in colder climates?
3. **[IF KNOW ABOUT HEAT PUMP PERFORMANCE IN COLD CLIMATES]** Where did you hear about it?
4. **[IF AWARE, PROBE]** Had you heard anything about their performance in colder climates?

C2. How did you first learn of the opportunity to receive a heat pump through Consumers Energy?

C3. What key concerns or considerations did you have when deciding whether or not to install the heat pump?

C4. What motivated you to agree to install the heat pump?
1. Were there any other factors? **[PROBE FOR COST, ENERGY SAVINGS, ENERGY-EFFICIENCY, REBATE FROM CONSUMERS ENERGY]**

C5. Did you have plans to install new heating or cooling equipment if Consumers Energy hadn't reached out to you?
1. **[IF WOULD HAVE INSTALLED NEW HVAC EQUIPMENT]** When would you have installed this new equipment?
2. What steps would you have taken to decide what equipment to purchase?

D. Experience with Contractor Selection and Installation Process

The next set of questions are about your experiences finding a contractor and installing of your new heat pump.

D1. So, once you decided to participate in Consumers Energy's Cold-Climate Heat Pump offering, can you talk me through the steps you took to find and select a contractor to perform the work?

D2. Did you have any difficulties finding a contractor to perform the work?

D3. How knowledgeable were the contractors you worked with about heat pumps? What about the installation process? **[PROBE IF ANY DID NOT SEEM TO BE KNOWLEDGEABLE ABOUT THE EQUIPMENT, WHERE THEY WERE LACKING KNOWLEDGE]**

D4. Once you found a contractor, how long did the project take from start to finish (purchasing to installing)? Did this timeline meet your expectations?
1. **[IF TIME EXPECTATIONS NOT MET]** What were your expectations?
2. **[IF TIME EXPECTATIONS NOT MET]** Is there anything that could have been done differently? **[PROBE IF ANY PART OF THE PROCESS TOOK LONGER THAN EXPECTED]**

D5. If you had to do it over again, would you work with the same contractor?

D6. Prior to the installation, what type of heating equipment did you use? Did you use electric or natural gas or another type of fuel to heat the property?

D7. What type of cooling equipment did you use?

D8. Did your contractor need to install new duct work, a new thermostat, or other infrastructure as part of the heat pump installation?

D9. What did your contractor do with the old heating system? **[PROBE IF REMOVED, KEPT IN PLACE AS BACKUP, CAPPED]**

D10. Did you need to install a new back-up system along with the heat pump? **[PROBE FOR HEATING OR COOLING SYSTEMS]**

E. Experience Using the Heat Pump

Next, I'd like to ask some questions about your experiences using the heat pump itself.

E1. What have been your experiences with operating the equipment to date?

E2. Have you had a chance to use the heating function on the heat pump that was installed at your facility?
   1. **[IF USED HEATING]** What time of year did you use the heating function? Did you have any issues with the heat pump providing sufficient heat for your comfort and meeting your needs? **[PROBE FOR IF THEY EVER HAD ISSUES PROVIDING HEAT]**

E3. Have you used the cooling function?
   1. **[IF USED COOLING]** Did you have any issues with the heat pump providing sufficient cooling for comfort and meeting your needs?

E4. Does the heat pump require any new operating procedures that you needed to learn how to use?
   1. How did that go?

E5. Does the equipment rely on a remote control or app?
   1. Do you use that feature?
   2. How has that gone?

E6. Have you had to change your heating/cooling habits in any way to accommodate the new technology?

E7. Have you noticed any changes in air quality since the heat pump was installed? **[PROBE: DECREASED AIR PARTICLES, NOXIOUS GASES, DEBRIS]**
   1. **[IF YES]** How so?

E8. How does the sound of the new equipment compare to your old heating/cooling equipment?
   1. **[IF SOUND WORSE]** What have you done to deal with the noise, if anything?

F. Experience with Pilot Offering

Next, I have a few questions about your experiences with Consumers Energy in relation to this pilot and then we'll be almost done.

F1. Did you interact with Consumers Energy program staff at any point in the process?
   1. **[IF YES]** What did you discuss?
   2. Did you get your questions answered?

F2. What additional support, if any, did you need *when considering to purchase and install* your heat pump?
   1. Who did you talk to? What questions did you have?

F3. Did you require any additional support—other than what you received from Consumers Energy—during the *installation process*?
   1. What about when using the equipment?

F4. Thinking about all the aspects of the initiative, from the support you received in picking equipment or a contractor to the financial rebate for the project, what aspect was most helpful in your decision to pursue the heat pump installation?

G. Satisfaction

I'd like to wrap up the conversation by asking you to rate your satisfaction on a few different factors.

G1. Feel free to expand on any answers you provide. Each of these items will be on a 1 to 10 scale, where 1 means *unacceptable* and 10 means *outstanding*.

Question	Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know / NA
The installation your contractor performed	O	O	O	O	O	O	O	O	O	O	O
The time it took to receive and install your equipment	O	O	O	O	O	O	O	O	O	O	O
The performance of the heat pump equipment	O	O	O	O	O	O	O	O	O	O	O
The interactions you had with your contractor	O	O	O	O	O	O	O	O	O	O	O
The overall Consumers Energy offering	O	O	O	O	O	O	O	O	O	O	O

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H. Closing

As we wrap up, I want to provide an opportunity for you to share anything I might have missed with my questions.

H1. Do you have any other comments or information you think might be useful for me to know given what we have talked about today?

H2. These are all the questions I have for you today. It is likely that one of our colleagues will be following up with you in a few months to better understand the energy use of your new cold-climate heat pumps during the winter months, so look out for that email or call. As a thank you for your input, we'd like to send you a $75 gift card redeemable at many businesses, including Amazon, Target, and Kroger. This gift card is called a Tango card and would be sent to your email address within the next five to 10 business days. Alternatively, we can donate the $75 to your local United Way. Which would you prefer?

H3. **[IF TANGO]** Could you please provide your preferred email address to receive the Tango virtual gift card? **[REPEAT BACK EMAIL ADDRESS]**
You should expect to receive your virtual gift card within the next five to 10 business days. The gift card will be emailed directly from **Tango,** with a reference to "Thank you for your participation!" If you have any questions, or have not received your gift card by then, please contact me at **[contact information]**.

H4. [IF UNITED WAY] In whose name should we make the donation to United Way? [INCLUDE FIRST AND LAST NAMES, COMPANY NAME, OR ANONYMOUS]
And what zip code should we use to find your local United Way?

On behalf of Consumers Energy, I want to thank you for taking time to provide input, and have a great day. **[END CALL]**

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Appendix G. Consumers Energy Heat Pump Contractor Interview Guide

Introduction and Purpose

Thank you for taking the time to talk with us today. This interview is a discussion about air source cold climate heat pumps, your businesses experience with the technology, and to assess the current status of the technology in the market. The intended outcome of this discussion is to document the perception, concerns, opportunities, critical decision points, and key outcomes involved with heat pump sales and installations. Consumers Energy can use this documentation to guide future decision making around their energy efficiency programs. We are offering a $75 gift card that can be redeemed at your choice of Amazon or Meijer for those that complete the 30-45 minute interview. We have four main objectives for this interview:

- Identify current levels of awareness and perceptions of heat pump technologies.
- Identify the main barriers to installing heat pumps in Michigan and if the Michigan market is ready for widespread adoption of heat pump technology.
- Identify any marketing or outreach best practices
- Document awareness of available heat pump incentive offerings

We expect this interview to take around 30 minutes.

A. General Introduction

A1. To begin, tell me about your business.
   1. What types of customers do you typically serve? [Standard residential? Income qualified? Multi-family? Commercial? Something else?]
   2. How many projects do you typically complete in a given year?
   3. How many employees does your company have?

A2. What type of equipment do you typically install? [Furnaces? Boilers? Heat pumps? Something else?]

A3. Do you have any experience participating in utility energy efficiency programs?
   1. Which utilities? Which programs? How often?

B. Heat Pump Awareness and Perceptions

B1. Does your company sell and install heat pumps?

1. **[If installs heat pumps]** How many (if any) heat pump sales or installations have you/your company had in the past year (2020)?
2. For those installations, do residents typically retain secondary or supplemental heating equipment after the heat pump is installed? Please describe.
3. What heat pump brands do you carry and install?
   Have you received any manufacturer-specific certifications for installing those brands?
4. How does the average warranty of a CCHP compare to gas furnaces or boilers?
5. **[If does not install heat pumps]** Why don't you install heat pumps?

B2. Do you promote CCHPs to your customers?

1. Are there specific applications or customer types that make good candidates for heat pumps? (i.e. retrofit vs. new construction)
2. Which ones?
3. Why?
4. Are small businesses good candidates for heat pumps?
   Are the barriers to entry different than the residential homeowner?

B3. Generally, what are your perceptions of CCHPs?

1. Do you think that CCHPs are a viable option for widespread adoption in Michigan?
2. Do you think that CCHPs are capable of generating energy savings for end users?
3. What has led to those perceptions of the equipment?
4. What do you think is the value proposition for you to want to install heat pumps? Why would you not want to?
5. Do you know other contractors who install CCHPs? What are their perceptions of the technology?

B4. What are customer perceptions of heat pumps?

1. Do they typically have any awareness of the technology?
2. What do you think is the value proposition for customers to install a heat pump? What are their motivations? If needed: Why would they not want to?
3. Do customers ever request to have the equipment installed without being prompted by your company? How do you respond to that request?
4. Is customer interest in heat pumps increasing, decreasing, or staying about the same? What would you say is causing that change?

B5. To what extent does a negative experience with older heat pump technologies affect your opinion about heat pumps? What about customers experiences?

C. Market Barriers and Regulatory Readiness

C1. **[If installs heat pumps]** How do procedures for a heat pump installation compare to installing other HVAC equipment in terms of:
1. Time required (actual installation time).
2. Sales process/discussions with customers.
3. Revenue/Profit Margin.
4. Equipment availability.
5. What factors can cause variations in these procedures? (e.g. conversion vs. replacing similar equipment).

C2. What would you say are the main barriers or challenges preventing more widespread heat pump adoption in Michigan? [Probe for: customer awareness, contractor perceptions, equipment availability, codes and standards, energy prices, finding good candidates, etc.]

C3. If demand for heat pumps increases, how well do you think the supply chain is prepared to meet that demand (increasing production) for cold climate heat pumps? Why?
1. Do you have any concerns about the availability or delivery timing of heat pump equipment for current or future projects? Why or why not?

D. Outreach and Marketing

D1. What can Consumers Energy do to help drive adoption of heat pumps in the market?

D2. Do you think that messaging is needed to educate people that CCHPs, or heat pumps in general, have improved?
1. **[IF YES]** What would effective messaging look like?

D3. **[If Promotes heat pumps]** When you have a good candidate for a heat pump, what information is most convincing for the customer to install a heat pump?

E. Wrap Up

E1. Before we wrap up, is there anything else you'd like us to know?

Those are all the questions we have for you. Thank you very much for taking the time to assist us with this evaluation. Your contribution is a very important part of the process. Do you mind if we follow-up with you by phone or e-mail later, if additional questions arise?

E2. To thank you for your time spent completing this survey, we would like to send you a $75 gift card to either Meijer or Amazon.com. Please choose which gift card you would like to receive.
1. $75 Meijer gift card
2. $75 Amazon.com gift card
3. Neither – I do not wish to receive a gift card

E3. Please provide your name, address, and email to receive your gift card. This information will only be used to mail your gift card.

1. Name:_____
2. Address:_____
3. Address 2:_____
4. City:_____
5. State:_____
6. Zip:_____
7. Email**:** _____

You should receive your gift card within four weeks. If you have not received it by then, please contact (contact person at Cadmus).

CADMUS

Appendix H. Consumers Energy Heat Pump Manufacturer and Distributor Interview Guide

Research Objectives and Questions

Research Objectives	Research Questions	Interview Questions
Confirm/document the supply chain for CCHPs in Michigan	Do CCHPs follow the typical supply chain structure (Manufacturer -> Distributor -> Contractor -> Customer)?	EE1, EE2
	Does the supply chain vary for small commercial, multifamily, and residential end uses?	EE1
Identify the barriers leading to extended timelines for CCHP installation	How long does it typically take from manufacturing to distribution? Distribution to contractors?	FF1
	What caused delays in the timeline in 2020? Have there been any changes to this timeline due to COVID-19? Were delays different across states? Did demand for CCHP in Michigan differ in 2020 compared to 2019?	FF1, FF2, GG2
	Are any delays expected to improve in 2021?	FF1
Identify sources of differences in CCHP installation costs across states	Are wholesale costs in Michigan comparable to other states?	FF3
	What factors drive pricing of CCHPs?	FF3
Explore the cause of low participation by trade allies	What have manufacturers and distributors done to promote heat pump technology?	GG5, GG6
	What feedback have contractors (distributors) offered to distributors (manufacturers) on perceptions of CCHP?	GG3, GG4
Identify any additional barriers and challenges delaying widespread adoption of CCHPs in Michigan, like training or education	What are the primary barriers or challenges faced by manufacturers / distributors in selling and distributing CCHP?	GG1, G1
Identify ways in which Consumers Energy can influence market adoption	How can utilities best support the adoption of CCHPs? Where is the correct place to offer an incentive (downstream, midstream, or upstream)?	II1
	Are there successful market influences in other states that could be promoted in Michigan?	HH1
	Are there technology advancements that Consumers Energy should be aware of?	HH2

A. Firmographics

First, I have just a couple questions about your organization and your role. Please note that I will keep your individual responses anonymous.

A1. What is your role in the company?

A2. What areas of the country does your company primarily serve?

A3. **[DISTRIBUTORS]** Do you serve as a distributor of heat pumps in states other than Michigan? **[PROBE FOR DETAIL]**

A4. **[MANUFACTURERS]** Do you work with particular states/regions or nationwide? **[PROBE FOR DETAIL]**

CADMUS

B. Supply Chain

Now I have some questions about the supply chain for the cold-climate air-source heat pump market. If possible, I would like you to focus your responses on the market in the state of Michigan.

B1. How does heat pump equipment typically get from the manufacturer to the end-use customer?
1. What are the key roles in the cold-climate heat pump market from production to installation (such as manufacturers, distributors, contractors, and electricians)?
2. Does the supply chain for cold-climate heat pumps differ from traditional air-source heat pumps? What about other types of mechanical equipment (such as furnaces, boilers, or water heaters)? If so, how?
3. Does the supply chain vary depending on the type of building where the unit will be installed (single family, multifamily, or small commercial building)?

B2. Are there particular distributors, manufacturers, or contractors you work with for cold-climate heat pumps in Michigan? **[PROBE FOR DETAIL]**

C. Timeline/Costs

Next, we would like to ask you some questions specifically surrounding production and distribution timelines and costs.

C1. On average, what would you say is the length of time it normally takes for a cold-climate heat pump to reach the distributor or contractor after an order is placed?
Does the timeframe in Michigan differ from other states?
1. **[MANUFACTURERS]** When fulfilling orders for cold-climate heat pumps, what specific manufacturing challenges, if any, have you experienced in the Michigan market? **[PROBE FOR DETAIL]**
2. How does this compare to other states?
3. Did production times change from 2019 to 2020? If so, how? What do you attribute this to?
4. What do you think production times will look like in 2021?
5. **[DISTRIBUTORS]** Have you experienced any issues with the availability of cold-climate heat pumps in Michigan? **[PROBE FOR DETAIL]**
6. How does this compare to other states?
7. Did availability change from 2019 to 2020? If so, how? What do you attribute this to?
8. What do you think availability will look like in 2021?
9. Does the timeline for cold-climate heat pumps vary by season? If so, how?

C2. **[DISTRIBUTOR]** Do you typically stock cold-climate heat pumps or do you place orders after a purchase is made?
1. How many units do you typically have on-hand? What types? Are NEEP specifications considered? What led to your decision to stock these units?
2. **[IF NOT]** What prevents you from stocking cold-climate heat pumps?

C3. Compared to other states, are cold-climate heat pumps in Michigan competitively priced?

1. Have costs been stable over time?
   [PROBE] Have costs differed from 2019 to 2020?
   [PROBE] Do you think that change is temporary?
2. **[MANUFACTURERS]** Has there been much variation in cost of parts and labor in the manufacturing of the cold-climate heat pumps?
3. **[DISTRIBUTORS]** Has there been much variation in cost based on availability of cold-climate heat pumps?

D. Demand/Adoption

I would now like to spend a few minutes talking about overall interest for cold-climate heat pumps in the market.

D1. Compared to other states, how much demand is there for cold-climate heat pumps in Michigan?

1. What do you see as the primary barriers or challenges that are restricting widespread adoption of heat pump technology in Michigan?
2. How do warranties for cold-climate heat pumps compare to warranties for other technologies (such as natural gas furnaces)?

D2. In 2020, did demand for cold-climate heat pumps in Michigan differ from 2019?

1. **[IF YES]** What do you think caused that change?
2. Do you think the change was temporary or will it be resolved?
3. Have there been any impacts on demand related to COVID-19, that you are aware of?
   [PROBE FOR DETAIL]

D3. **[MANUFACTURERS]** What feedback have you received from distributors in Michigan about heat pump technology adoption?

1. What about cold-climate heat pumps, specifically?
2. Is this different from other states?

D4. **[DISTRIBUTORS]** What feedback have you received from contractors in Michigan about heat pump technology?

1. Is this different from other states?

D5. Do you know of any promotions or trainings your organization does to increase awareness of cold-climate heat pumps among your customers in Michigan?

1. Does this differ from other states?
2. Is this different from other types of equipment?

D6. Specifically, what has your organization done to promote heat pump technology to distributors/contractors?

1. Have you offered trainings, informational pamphlets, sales/discounts, or something similar?

E. Solutions

In this final section, I'd like to shift gears a little to understand your thoughts on how Consumers Energy and other utilities could provide support to further the adoption of cold-climate heat pump technology.

E1. Is there anything you think utilities could do to improve the adoption of cold-climate heat pump technology in Michigan? **[PROBE FOR DETAIL; SOLUTIONS BEYOND INCREASING INCENTIVES]**
   1. In your opinion, where is the right place to offer an incentive to drive adoption of a newer product such as cold-climate heat pumps (downstream, midstream, or upstream)?
   2. Have you seen models for promoting the adoption of cold-climate heat pumps in other jurisdictions that Consumers Energy should consider?

E2. Are there any recent or upcoming advancements in heat pump technology that Consumers Energy should be aware of?

F. Closing

As we wrap up, I want to provide an opportunity for you to share anything I might have missed with my questions.

F1. Do you have any other comments or information you think might be useful for me to know given what we have talked about today?

F2. These are all the questions I have. As a thank you for your input, we'd like to send you a $75 gift card to Amazon, Target, or Meijer. Amazon and Target gift cards are virtual and would be sent to your email address within the next 5 to 10 business days. Meijer is offered as a physical gift card, which will be mailed to your preferred address. Alternatively, we can donate the $75 to your local United Way. Which would you prefer?
   1. Amazon
   2. Target
   3. Meijer
   4. Please donate to my local United Way

F3. **[IF G2=1 OR 2]** Could you please provide your preferred email address to receive the **[AMAZON OR TARGET]** virtual gift card?

F4. **[IF G2=3]** Let me ask the information we need to mail your gift card to the intended recipient—this could be you personally or anyone else of your choosing:
   1. First name of recipient:
   2. Last name of recipient:
   3. Could you please provide the street address we should use to send the gift card?

You should expect to receive your gift card by no later than **[DATE]**. If you have any questions, or have not received your gift card by **[DATE]**, please contact **[contact information]** and reference the Consumers Energy heat pump interview.

F5. **[IF G2=4]** In whose name should we make the donation to United Way? **[INCLUDE FIRST AND LAST NAMES OR COMPANY NAME]**

On behalf of Consumers Energy, I want to thank you for taking time to provide input, and have a great day. **[TERMINATE]**

Across building types, single-family homes could be most likely to convert to hybrid ASHP, though there are obstacles to conversion

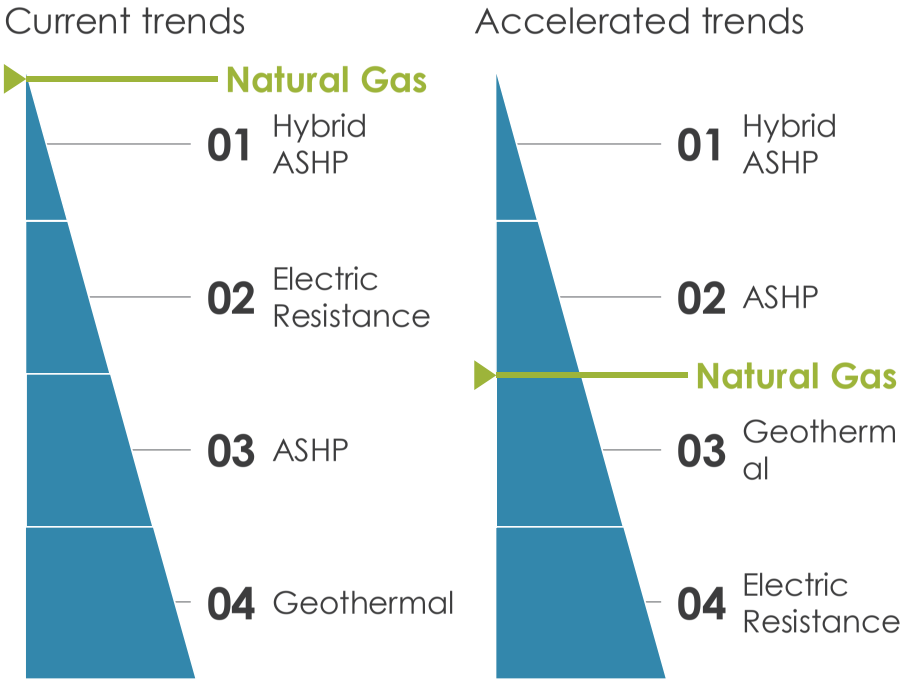
ILLUSTRATIVE ANALYSIS

Single-family homes – Urban

Considerations for converting away from natural gas space heating

- **Easier to convert**, due to less retrofit complexity
- **Individual decision-makers** (as compared to a co-op or HOA in a multi-unit building) enables more rapid decision-making to convert
- Lack of space may be a challenge, but **94% of single family homes are detached**, with more available space for heating appliances
- **Upfront cost of converting from natural gas to electric can be a deterrent** for many households
  - New gas furnace + installation: $ 4.500
  - New ASHP + installation: $12.000

Preferred technology based on trends assumptions



Compared to other building types, non-urban single-family homes may be able to more easily convert to geothermal space heating

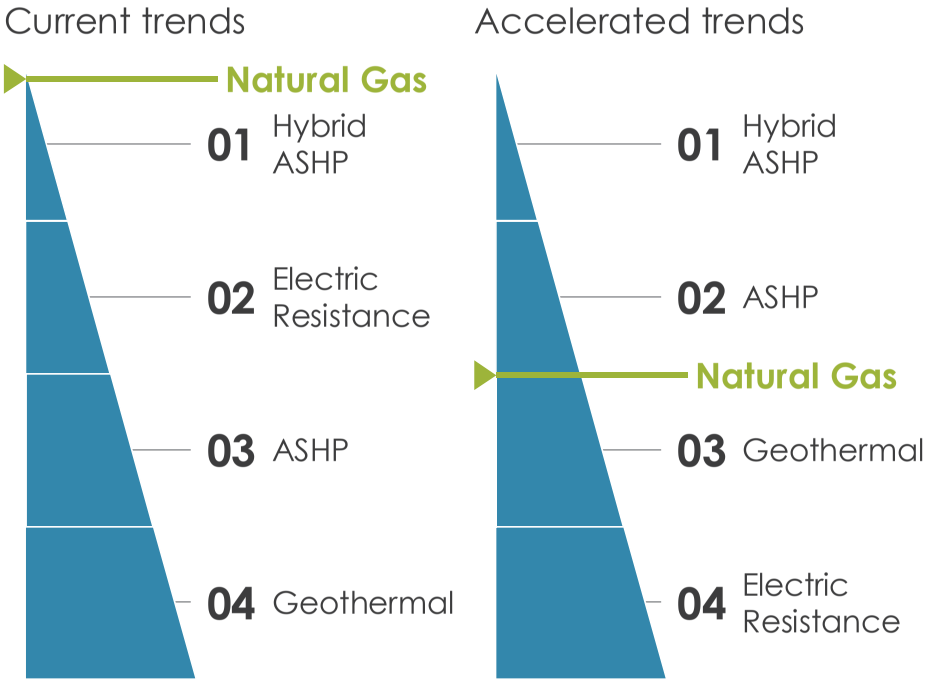
ILLUSTRATIVE ANALYSIS

Single-family homes – Non-urban

Considerations for converting away from natural gas space heating

- **Easier to convert**, due to less retrofit complexity
- **Available land** for technologies requiring more space
- **Individual decision-makers** (as compared to a co-op or HOA in a multi-unit building) enables more rapid decision-making to convert
- Located in least congestion areas, therefore **likely won't to require electric grid upgrade**
- **Upfront cost of converting from natural gas to electric can be a deterrent** for many households
  - New gas furnace + installation: $ 4.500
  - New ASHP + installation: $12.000

Preferred technology based on trends assumptions



Electrification is more challenging for multi-family home buildings compare to single-family homes due space constraints and stakeholder coordination

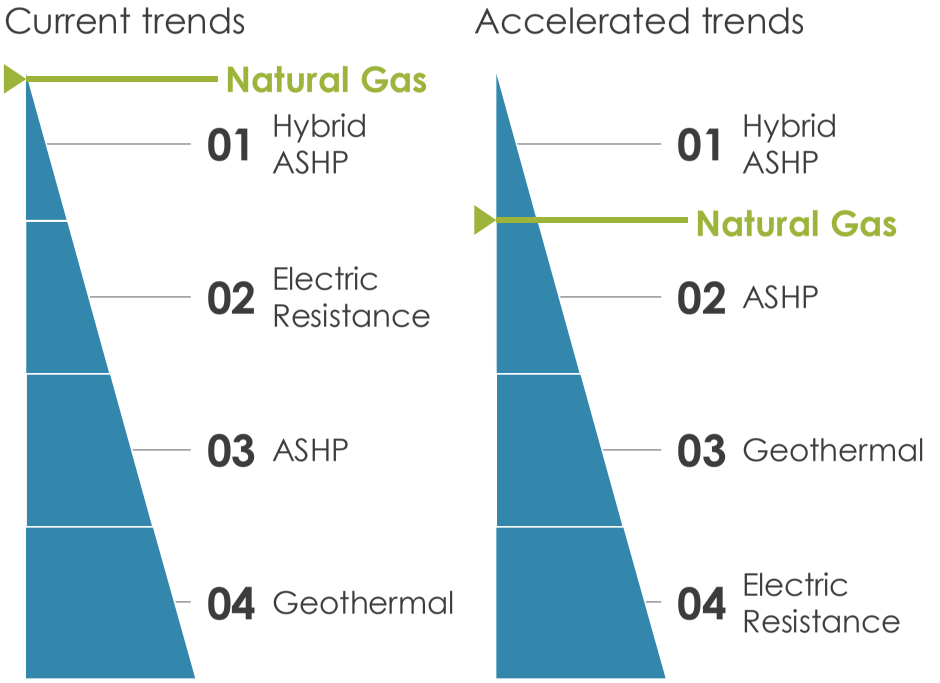
ILLUSTRATIVE ANALYSIS

Multi-family homes

Considerations for converting away from natural gas space heating

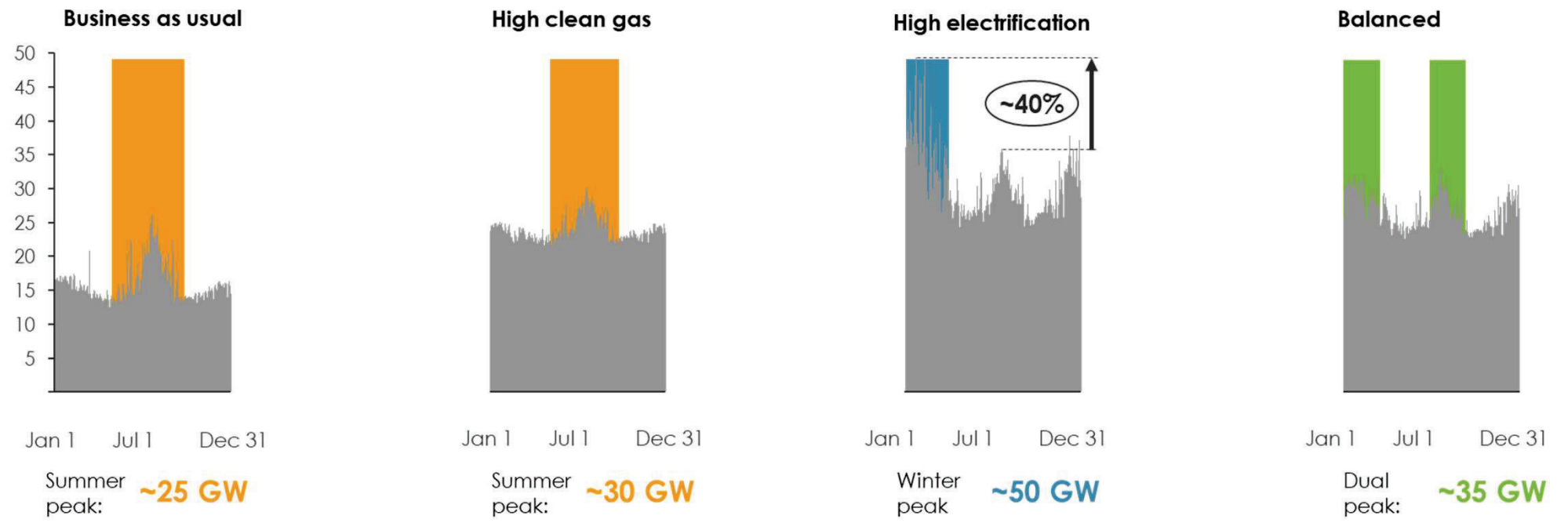
- Harder to convert, due to **complexity and costs associated with retrofit**
- **Lack of space** can make some technologies unfeasible
- **Collective decision** imposes additional challenge, as households with different preferences / willingness to invest, must agree upon technology
- Located in congestion areas, therefore **likely to require electric grid upgrade**

Preferred technology based on trends assumptions



Michigan Energy Load by Scenario

MI daily maximum electric load, from January 1 to December 31, 2050, GW

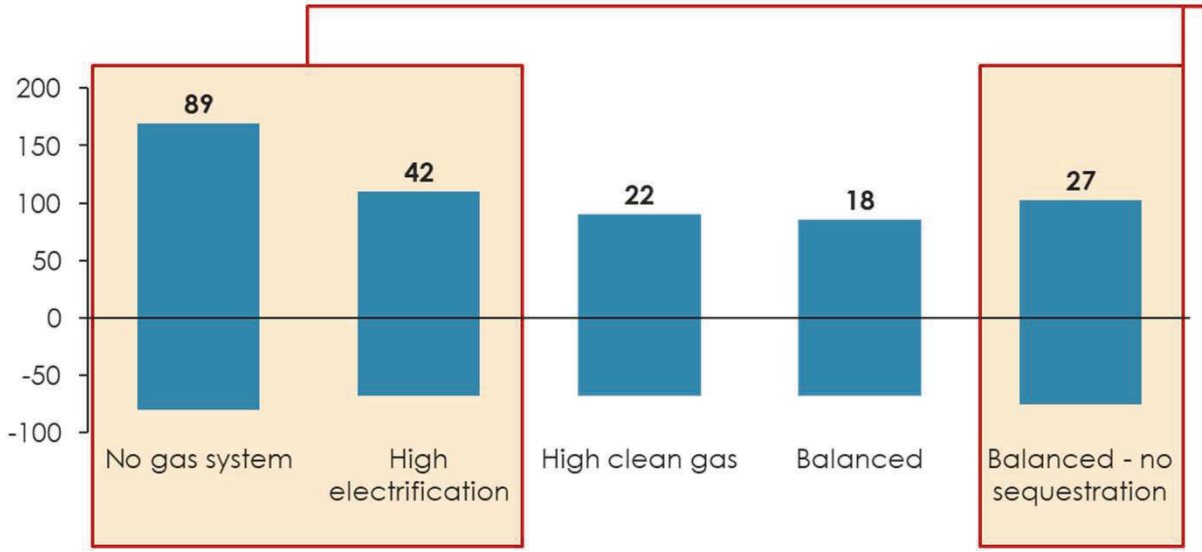


Winter peak with high electrification has significant cost implications due to additional electric T&D build out

Michigan Societal Cost Impact by Scenario

NPV of total system costs relative to reference case[1]

$B, 2020 – 2050, all of Michigan



Disallowing either the natural gas system or sequestration from the system results in **prohibitively expensive pathways**

1. **Gas distribution** enables cost effective heating
2. **Gas transmission is needed to supply gas to power plants that firm renewable power**
3. **Carbon sequestration** is needed to cost effectively negate emissions
4. Gas provides **system resiliency, diversification**, and energy for **hard-to-electrify end-uses**

1. Gas infrastructure costs based on high-level initial assessment. Granular data on Michigan-system pipeline inventory can be used to develop more detailed analyses

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State of Michigan
Department of Licensing and Regulatory Affairs

Michigan Public Service Commission

Renewable Energy and Electrification Infrastructure Enhancement and Development Grant

RESPONSE DOCUMENT

Bidder Name: Consumers Energy Company

ESTIMATED TIMELINE	
Issue Date	December 20, 2023
Inquiries Due (round one)	January 11, 2024
Reponses to Inquiries Posted	January 18, 2024
Inquiries Due (round two)	January 26, 2024
Responses to Inquiries Posted	February 5, 2024
Proposals Due	February 21, 2024
Proposals Posted Publicly	February 28, 2024
Public Comment Period End Date	April 12, 2024
Modified Proposals Due	April 29, 2024
Modified Proposals Posted Publicly	May 1, 2024
Anticipated Announcement of Grant Awards	September 2024
Anticipated Grant Start Date	November 15, 2024

PART III: WORK STATEMENT

III-A Purpose

The purpose of this Request for Proposals (RFP) is to obtain proposals from businesses, nonprofit organizations, local units of government, and tribal governments, for the purpose of planning, developing, designing, acquiring, or constructing renewable energy and electrification infrastructure projects. The MPSC may consider awarding up to 10% of the funding available to planning grants. The MPSC welcomes all technologies, project sizes, and locations to apply, consistent with the language outlined in Public Act 119 of 2023.

From the total amount of funding for grants awarded for electric vehicle fast-charging infrastructure, 25% of that total amount must be allocated for infrastructure that provides charging at a power level of 350 kilowatts or less and 75% of that total amount must be allocated for infrastructure that provides charging at a power level of more than 350 kilowatts.

NOTE: The MPSC reserves the right to award funds for an amount other than that requested and/or request changes to, or clarification of any and all proposals received as a result of this RFP.

III-B Problem Statement

This grant will support renewable energy and electrification infrastructure enhancement and development projects.

III-C Objectives

Prioritized infrastructure or planning projects funded hereunder will meet one or more of the MI Healthy Climate Plan goals, specifically to:

1. Commit to environmental justice and pursue a just transition
2. Clean the electric grid
3. Enable electric vehicle charging infrastructure and increase public transit
4. Repair and decarbonize homes and businesses
5. Drive clean innovation in industry
6. Protect Michigan's air, land, and water

III-D Tasks

The tasks outlined below must be included in an application for either a renewable energy and electrification facility or program (infrastructure) grant or a renewable energy and electrification planning grant.

A. Renewable Energy and Electrification Facilities or Program Infrastructure Grant applicant(s) must include the following to be considered for an award:

1. Submit an impact study of the project that includes an analysis of the following:
   a. Potential cost savings.
   b. Environmental impacts. In calculating the carbon emission reductions, a life cycle approach utilizing the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) Model developed by Argonne National Laboratory is preferred. Emission must be expressed in terms CO2e (carbon dioxide equivalent).
   c. Local economic benefits.

   Note: A utility, at its sole discretion, may prepare a single impact study covering the utility's service territory that accounts for likely proposals, evaluates regional opportunities, and minimizes or eliminates the need for repetitive studies.

2. Submit details addressing how the proposed project will align with the governor's MI Healthy Climate Plan.
3. Submit a detailed project timeline and Gantt chart. The estimated grant start date is November 15, 2024. Projects must be completed by August 15, 2026 for the portion of the project being funded by the grant.

B. Renewable Natural Gas (RNG) Infrastructure Grant applicant(s) must include ALL of the following to be considered for an award:

"Renewable natural gas" or "RNG" means methane derived from organic material and degradable carbon sources, including, but not limited to, carbon sources and materials sourced from municipal solid waste, plant materials, or food waste. Renewable natural gas injected into a pipeline for downstream use must meet pipeline quality specifications.

1. Submit an impact study of the project that includes an analysis of the following:
   a. The project details, including the location of renewable natural gas and the proposed interconnection.
   b. The cost estimates for the interconnection, metering, and gas conditioning equipment needed to connect to an existing pipeline system.
   c. A summary of the environmental and health impacts of the project, including the forecasted emission reductions. In calculating the carbon emission reductions, a life cycle approach utilizing the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) Model developed by Argonne National Laboratory is preferred. Emission must be expressed in terms CO2e (carbon dioxide equivalent).
   d. Any local economic impact from the RNG infrastructure development.
   e. The end-use application for the RNG infrastructure with a focus on projects being used for opportunities in this state.
2. Submit details addressing how the proposed project will align with the governor's MI Healthy Climate Plan.
3. Submit a detailed project timeline and Gantt chart. The estimated grant start date is November 15, 2024. Projects must be completed by August 15, 2026 for the portion of the project being funded by the grant.

C. Renewable Energy and Electrification Facilities or Program Planning Grant applicant(s) must include ALL of the following to be considered for an award:

1. Submit a narrative including all of the following information:
   a. Explanation of what planning will be taking place and how the grant award will be spent.
   b. Explanation of the future project(s) which the planning is being conducted for.
   c. Detailed Timeline and Gantt chart for the planning to be conducted and the future project being planned for. The estimated grant start date is November 15, 2024. Planning must be completed by August 15, 2026 for the portion of the project being funded by the grant.
   d. Potential impact to Michigan citizens and businesses, including how the planning grant applicant intends to engage affected or surrounding community members and stakeholders in planning and project design and/or implementation.
   e. How the future project(s) the planning is being conducted for will align with the governor's MI Healthy Climate Plan.

2. Identify potential funding sources to undertake construction of facilities or implementation of programs that a planning grant is being conducted for.

PART V: INFORMATION REQUIRED FROM APPLICANT(S)

Applicant(s) must submit one proposal. **Electronically submitted proposals must have a scanned signature or e-signature** and cannot exceed 15 MB.

Applicant(s) must provide responses to each section below. **The RFP Response Template document can be found on the Renewable Energy and Electrification Infrastructure Enhancement and Development Grant webpage.** Be as descriptive as possible and answer each question in its entirety; some questions have multiple components. In your responses, provide a straight-forward, concise description of the applicant(s)'s ability to meet the requirements of the RFP.

Questions that do not apply should be answered "N/A."

V-A Identification of Organization

Applicant will provide the following:

1. State the full name and address of the organization.
2. The organization's federal identification number.
3. The organization's telephone numbers.
4. What percentage of the organization is located in Michigan.
5. The organization's SIGMA ID number. Refer to Section I-B, Eligibility Requirements.
6. The organization's SIGMA ordering mail code Refer to Section I-B, Eligibility Requirements.
7. Name of the authorized signer(s) for any future grant agreements, their title, telephone number, fax number, and electronic mail address.

Bidder response:

1. Consumers Energy Company
   One Energy Plaza
   Jackson, MI 49201
2. Federal ID Number: 38-0442310
3. 800-477-5050
4. Company is 100% located in Michigan
5. SIGMA ID number, CV0018795
6. SIGMA Address Code: 008
7. Holly Bowers
   Vice President, Gas Engineering and Supply
   Phone: 517-740-3232
   Fax: 1-800-363-4806
   Email: holly.bowers@cmsenergy.com

V-B Authorized Negotiator

State the name of one (1) contact person and their title, telephone number, fax number, and electronic mail address. The contact person must be authorized to be the negotiator for the proposed Grant Agreement with the State of Michigan.

Bidder response:
Neal Dreisig
Sr. Strategy Manager
Phone: 989-239-8071
Fax: 1-800-363-4806
Email: neal.dreisig@cmsenergy.com

V-C Project Summary

Please provide a project summary not more than 500 characters in length.

Bidder response:
The proposed network geothermal Planning Project supports Public Act 119 of 2023 and objectives of the MI Healthy Climate Plan including environmental justice, decarbonizing homes and businesses, and clean innovation energy hubs. The Project seeks to site, configure, model and assess cost and benefits for a network geothermal system that best supports environmental justice, carbon reduction, energy efficiency, and energy cost savings.

V-D Method for Addressing the Problem

State in succinct terms how the applicant(s)'s proposed project will support renewable energy and electrification infrastructure enhancement and development. Refer to Section III-B, Problem Statement.

Bidder response:
The Planning Project is an electrification technology and infrastructure development project that will identify, assess and plan for the most cost effective and energy efficient location to electrify natural gas end uses using network geothermal system technologies that are mature and readily available today.

V-E Project Objectives

Explain how the applicant's infrastructure or planning project will meet the goals of the MI Healthy Climate Plan. Refer to Section III-C, Objectives. Also include any other identified project metrics that will be included in the project status reports as referenced in Section IV-B.

Bidder response:
The network geothermal Planning Project supports MI Healthy Climate Plan goals by reducing emissions related to heating Michigan homes and businesses 17 percent by 2030, and achieving economy-wide carbon neutrality by 2050. The MI Healthy Climate Plan says that "reaching our mid-century milestone will require particularly substantial effort and innovation in the sectors of our economy that are hardest to decarbonize, including industry, buildings and housing, and agriculture." Network geothermal uses mature technology innovatively to maximize energy efficiency and cost of energy in the most impacted regions.

1) **Commit to environmental justice and pursue a just transition**. With efficiencies up to 600%, network geothermal systems provide superior cost of energy savings and work best in regions with diverse energy loads and the patterns of those loads. Diverse load profiles makes low-

income neighborhoods often adjacent to industrial parks ideal for planning. Planning activities will assess these regions, using the Michigan Environmental Justice (MiEJ) screen, that best fit network geothermal system profiles. Additionally, planning activities support the Michigan State Housing Development Authority (MSHDA) 2022 Statewide Housing Plan goals, as described under "MI Healthy Climate Plan" section.

2) **Clean the electric grid.** The Planning Project will assess how network geothermal systems in specific locations mitigate seasonal peak electric loads and intermittency of renewable energy sources in an electrified future. With energy efficiencies upwards of 600%, network geothermal heating and cool capabilities could meaningfully mitigate increased costs associated with the buildout of electric infrastructure, therefore limiting the energy burden for cleaner electricity.

3) **Repair and Decarbonize homes and businesses.** The Planning Project directly supports eliminating emissions tied to the combustion of natural gas users using the most energy efficient technology available today. The network geothermal system will reduce approximately 8 tons of Carbon Dioxide equivalents (CO2e) per year per home using the Greenhouse Gases (GHG), Regulated Emissions, and Energy Use in Technologies (GREET) Model developed by the Argonne National Laboratory. The magnitude of overall carbon reduction will be assessed during planning and dependent on the size of the network.

4) **Drive clean innovation in industry.** As described in the MI Healthy Climate Plan, work should "encourage clean innovation hubs where private enterprises strategically co-locate and collaborate to develop and deploy new, cleaner manufacturing technologies and conduct research and development to reduce emissions from hard to decarbonize industries."[1] The essence of network geothermal systems is their hub-like ability to scale and pass benefits along to those connected to the network.

5) **Protect Michigan's air, land, and water.** The Planning Project supports air quality in Michigan by reducing emissions and mitigates environmental impacts associated with sourcing, transporting and burning fossil natural gas.

Primary metrics the Project will measure against include:

- Cost of energy savings per end user, measured in annual dollars saved
- Net energy efficiency impact, measured in the ratio of useful energy delivered to the amount of energy input into the system
- Carbon reduction, measured in tons CO2e and $/ton CO2e

V-F Work Plan

Provide a detailed work plan based on the requirements outlined in Part III-D Tasks. The applicant's impact study must be attached to the application. If applicant is applying for a Planning Grant, the Planning Narrative should be described in this section.

Bidder response:

1) Planning Project Narrative

[1] MI Healthy Climate Plan. (2022). Retrieved from MI Healthy Climate Plan (michigan.gov)

A. Planning Explanation

A networked geothermal system is a network of ground source heat pumps connected via common ground circuits as shown below in Figure 1. Network geothermal systems have two unique attributes. They share energy between demand centers, where a business that rejects heat for cooling purposes can be used down the street by a home for heating purposes, thereby greatly increasing energy efficiency. Secondly, these systems store excess heat in the earth during cooling seasons and withdraw that same heat months later during heating seasons just like a natural gas storage field. For these reasons, network geothermal systems drive energy efficiencies upwards of 600%.

Networked geothermal systems are mature technologies, used for decades on college campuses, and well considered the most energy efficient form of heating and cooling. Two natural gas utilities, Eversource and National Grid, have network geothermal demonstrations approved through public service commissions today with plans to expand.

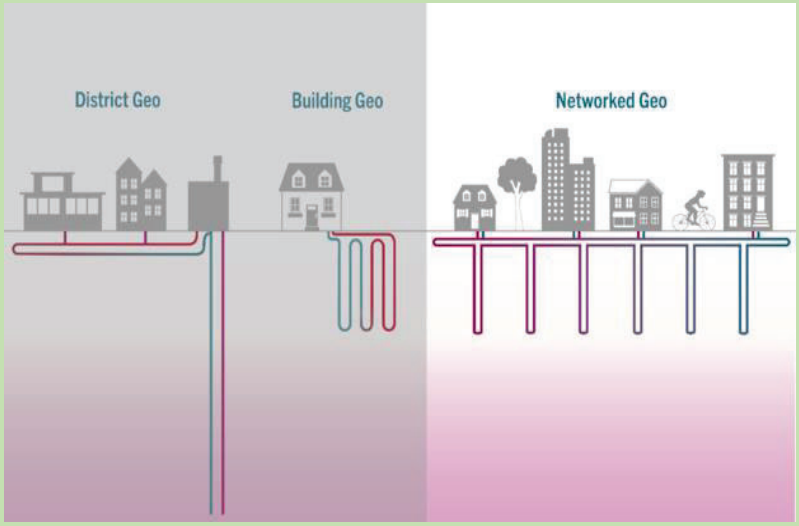

Figure 1 – Various geothermal system configurations

The outcome of the Planning Project is the following:

- Site and configure a network geothermal system in Consumers Energy's gas service territory given factors such as demographics, climate, geology, community interest, energy use diversity, and impacts to the existing system.
- Determine net energy impacts of the network geothermal system including incremental power consumption of heat pumps compared against energy efficiency gains.
- Determine additional costs to the electric distribution system and electric capacity needed to support a network geothermal system.
- Assess potential impacts to energy market prices due to additional energy demand.
- Determine how to best use existing tax subsidy incentives to reduce network geothermal system cost.
- Determine cost benefit analysis for homes and businesses on a network geothermal system including analysis for specific customer classes.
- Quantify the carbon reduction potential for the network geothermal system.
- Assess the scale of network geothermal systems throughout Consumers Energy's gas service territory.

Before the grant start date, a service territory wide assessment will occur to identify candidate locations ideal for network geothermal systems. Initial due diligence indicates Flint, Lansing, Jackson,

Battle Creek and Kalamazoo are potential sites. Initial community engagement activities will also occur before the grant start date to better understand community participation interest. Community engagement is described in further detail below.

Planning will occur in six (6) phases: site identification, site-specific geological evaluation, energy modeling, thermal resource assessment, infrastructure and implementation design and cost benefit planning. Grant award funds will be used to complete these six (6) phases.

i. **Site identification**: Site identification will be informed by service territory wide due diligence showing optimum locations for a network geothermal system based on MiEJ screen, population density, annual gross domestic product (GDP), GDP growth, demographic composition, diversity of energy load, current natural gas consumption, customer feedback and existing electric and gas infrastructure. These criteria will inform which location best supports disproportionately impacted communities, customer affordability and the MI Healthy Climate Plan. This phase will assess all criteria and select a site for further planning.

ii. **Geological evaluation**: Site specific geological evaluation will occur in two steps, deep (step one) and shallow (step two) evaluations. An initial deep test boring will evaluate geothermal capabilities of the site. Deep test borings will also evaluate glacial overburden and underlying bedrock characteristics to a depth of several hundred feet. The deep boring will provide thermal conductivity testing results to evaluate and obtain preliminary geothermal design characteristics.

Step two of the geotechnical evaluation will evaluate the shallow subsurface conditions to obtain parameters necessary for design of the overall system, including placement of network piping. Geotechnical investigations consisting of drilling soil test borings may include Standard Penetration Testing (SPT), undisturbed soil sampling using Shelby tubes, and other in-situ tests such as vane shear or groundwater monitoring. An overall subsurface geotechnical field assessment will be derived consisting of logging each test boring, performing soil/rock testing, and fluid testing.

Results of the field investigation and any corresponding recommendations will be documented in an engineering report including logs of test borings, a test boring location plan, results of thermal analysis, a summary of findings, and present evaluations, conclusions, and recommendations for the geothermal system.

iii. **Energy Modeling**: A thermal energy model will be developed using the determined geological characteristics. The thermal model will assess a network up to ten industrial/commercial structures and twenty residential structures. The model will be broken into clusters based on phasing and construction, which will be used in TRNSYS modeling software to determine the locations of all thermal energy resources within the system. The modeling software takes all energy load diversities and energy sharing into account when designing thermal resources.

This Phase will also look at incremental energy requirements for heat pumps and the associated energy load profiles across peak heating and cooling seasons to understand how the network geothermal system impacts electric loads, capacity requirements and market prices.

iv. **Thermal Resources**: This phase involves design and configuration of the network including geothermal heat exchangers to optimize energy and available space. This phase will also assess existing utilities within the street right of way (ROW). Other potential thermal resources such as water retention ponds, surface water systems or wastewater energy transfer (WET) systems that capture and reject heat into the community's main sewer line will also be assessed.

v. **Infrastructure Planning and Implementation**: This phase includes planning for mechanical and civil work to produce a conceptual distribution system design, geothermal fields, building interface, pumping stations, and central plant facilities as applicable. This phase also includes system descriptions, process diagrams, equipment lists, schematic arrangement drawings of central facilities, geothermal fields, and building interfaces. The outcome of this phase will be a schedule and conceptual execution plan including contracting methodology for development, construction, and operation of the system.

vi. **Cost benefit assessment**: Using the work in previous phases, this phase will develop a capital estimate, operations and maintenance estimate, infrastructure requirements, market price impacts, subsidy incentives, energy and associated cost savings, existing building retrofits required to connect to the network, and carbon reduction to determine the overall cost benefit attributable to specific customer classes. Capital cost estimates will include design, engineering, permitting, borehole drilling, drilling rig setup, ground circuit installation, heat pumps or circulating pumps, service connections to buildings, building envelope conversions and public ROW work.

B. Future project

Planning activities described above will provide the business case for a network geothermal system project at the selected site. A future project would continue with community engagement (described in detail below) and Michigan Public Service Commission collaboration to determine the appropriate path forward given results of planning activities.

Primary objectives from an initial project would be to demonstrate the reasonableness of scale, bill savings to customers, performance of shared energy circuits, energy efficiencies, and optimum configurations for Michigan's geology and the State's climate.

C. Timeline

See response box below for discussion on Planning Project timeline along with Attachment C, Gantt Chart.

D. **Impacts to Michigan citizens and businesses**

i. Planning activities and potential future projects have significant positive impacts to citizens and businesses, summarized below. Network geothermal is unique in that diverse energy loads are shared across the network, reducing energy consumption. In addition to energy sharing, network geothermal systems are preferred over air source heat pumps (ASHPs) due to superior energy efficiencies. The inherent properties and

heat transfer characteristics of water and soil allow network geothermal systems to provide efficiencies upwards of 600%. This is due to the ground maintaining stable temperatures all year, providing a reliable heat source compared to ambient air. Additionally, groundwater and soil are denser allowing better heat transfer characteristics than air. This means network geothermal systems obtain more heating energy per unit volume, which means greater energy efficiency. Further details are discussed in subpart E, MI Healthy Climate Plan.

Positive impacts to homes and businesses:

- Energy efficiencies upwards of 600%;
- Cost of energy savings due to high efficiencies;
- Less risk associated with water pipes as compared to natural gas pipelines;
- Emissions eliminated from combustion of fossil natural gas;
- Strong support for disproportionately and environmentally impacted communities;
- Economic development for businesses that support drilling, heating ventilation and air conditioning (HVAC), polyethylene pipe manufacturing and excavation.
- Excellent opportunity for clean energy job transition.

ii. A primary objective of planning activities and potential future project is understanding the willingness of existing natural gas customers to adopt geothermal heating technology. As noted, initial community engagement will occur ahead of the grant start date to educate on geothermal benefits, gauge participation interest and identify anchor users for specific locations. Anchor users are defined as higher load entities that reside near homes and other businesses.

As part of community engagement, a Community Stakeholder Engagement (CSE) Plan will be developed. A CSE uses a structured approach to building relationships with current stakeholders and disadvantaged communities. This framework is essential for proactively engaging potentially affected communities in upcoming projects, aiming to deliver community benefits, quality employment opportunities, and address any potential environmental concerns in a meaningful and impactful manner.

Upon reaching the grant start date, site selection will occur based on prior assessments and community feedback as described above. Concurrently with planning activities, a Stakeholder Engagement Group (SEG) will be created, ensuring a diverse representation of community priorities.

Throughout and after planning activities, CSE will be implemented. The two-way engagement will be dynamic, allowing for flexibility and adjustments based on insights gained through planning activities and engagement efforts. This approach will ensure a potential future project aligns with the evolving needs of community stakeholders. Feedback and insights collected from engagement activities will undergo a thorough analysis, serving as the foundation for continuous updates to engagement strategies and refining community priorities.

E. MI Healthy Climate Plan

The Planning Project directly contributes to the MI Healthy Climate goal of reducing emissions associated with heating homes and businesses 17% by 2030, achieving economy-wide carbon

neutrality by 2050 and maintaining net negative GHG emissions thereafter, while supporting disproportionately and environmentally impacted regions.

Environmental Justice and Pursue a Just Transition

As noted in the MI Healthy Climate Plan and research performed by Rewiring America, heat pump technology could provide immediate savings to Michigan homes. Network geothermal systems, which use heat pump technology, provide the highest cost of energy savings and are ideal for disproportionately impacted regions. The diverse energy load patterns of these regions where homes are near commercial and industrial sites make for ideal network geothermal systems.

In the coming decades, higher income residents are likely to adopt isolated electrified end uses first, leaving low-income customers subject to the fixed costs of the remaining natural gas network. Network geothermal evolves the natural gas system grid by grid, starting with low-income regions, so no one is left behind.

a. Michigan Environmental Justice (MiEJ) screen

The MiEJ screen will be used to help identify candidate locations for planning. The MiEJ screen uses 26 indicators summarized by 4 overall criteria to assess overall community impacts. Environmental indicators look at risk, pollution, or exposure to nearby facilities. Health and socioeconomic indicators look at a population's vulnerability or to pollution. As noted, "the screening tool is a useful first step in understanding or highlighting locations that require further review."[2] Based on initial screens, Flint, Lansing, Jackson, Battle Creek and Kalamazoo are potential sites for further evaluation.

b. MSHDA State-wide Housing Plan

Planning activities also support specific goals for the MSHDA 2022 Statewide Housing Plan. Planning activities will align with these goals throughout the process:

Goal 1.5: Increase opportunities for resident input throughout the development process.
Goal 4.3: Ensure that new housing development meets State climate and healthy housing goals and is affordable for the lifetime use of the building without increasing costs to residents.
Goal 4.5: Increase environmental sustainability, energy efficiency, and weatherization in housing rehabilitation and/or preservation.

c. Just transition of workforce

There are similarities between shared geothermal networks and natural gas networks, including materials, installation methods of underground pipe, permits, drilling boreholes, right of way work, and monitoring the system conditions to ensure safety and reliability service for customers. There are low barriers to transition due to these close similarities. For example, fluid pipes in network geothermal systems use the exact same polyethylene pipe material as natural gas distribution systems. This enables a quicker and more equitable transition than the current building-by-building approach for air source heat pumps.

Clean the Electric Grid

Network geothermal systems support a cleaner electricity grid by using the lowest total energy over the course of a year to heat and cool homes. Specifically, network geothermal systems reduce peak heating and cooling loads and mitigate the need to potentially expand electric infrastructure. This benefit will become more valuable as shoulder seasons potentially become shorter.

[2] MiEJ Screen. (2023), retrieved from MiEJScreen-Factsheet.pdf (michigan.gov)

Analysis performed by HEET in Figure 2 shows the incremental peak load in high demand seasons using various electrification technologies for space heating.[3] With efficiencies upwards of 600%, it is clear network geothermal systems have negligible impact to peak electric load in a highly electrified future. This ultimately helps citizens of Michigan avoid cost impacts of adding new electric capacity.

Like battery storage, network geothermal systems use the earth as a thermal battery. In this way, intermittency issues tied to solar and wind energy are mitigated by requiring less energy during off-peak hours.

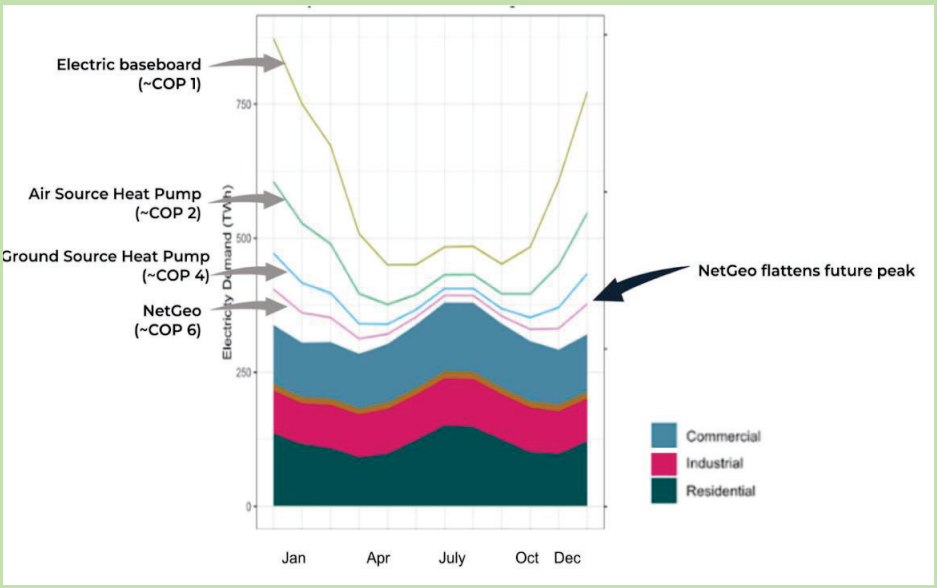

Figure 2 – Peak electric loads by technology

Repair and Decarbonize Homes and Businesses

The MI Healthy Climate Plan assessed that "replacing traditional fossil fuel use with cost-effective technologies that rely on electricity" can effectively decarbonize building heating.[4] The Planning Project will determine the extent of carbon reduction in Michigan using network geothermal systems. With natural gas showing a lifecycle emission of approx. 80 grams CO2e per megajoule, network geothermal systems could demonstrate meaningful impact in reducing carbon when scaled.

Prior analysis by Consumers Energy, confirmed by 3rd party experts, indicates that the combination of clean fuel technologies provides the most cost-effective solution to reaching the MI Healthy Climate Plan goals. Each technology including network geothermal, air source heat pumps, renewable natural gas, hydrogen, carbon capture, synthetic gas and long-term storage all reduce carbon affordably in unique sectors of society. Network geothermal systems may provide the most cost-effective form of electrification for low-income regions which this Planning Project seeks to understand.

Drive Clean Innovation in Industry

The Planning Project seeks to understand the scalability of network geothermal using a hub-like approach. Like municipal water and natural gas systems, network geothermal systems can be added onto making the system more diverse and energy efficient. Starting with a central hub network,

[3] HEET. (2023). Networked Geothermal. Retrieved from Networked Geothermal Wiki (gastogeo.wiki)
[4] Department of Environment, Great Lakes, and Energy. (2022). MI Healthy Climate Plan. Available at MI Healthy Climate Plan (michigan.gov)

planning activities will focus on the extent to which network geothermal can become scaled regional hubs.

Protect Michigan's Air, Land and Water

As noted above, the Planning Project supports air quality in Michigan by reducing emissions associated with sourcing, transporting and burning fossil natural gas. Network geothermal systems are ideally installed in existing rights of way for existing public utilities, which mitigates impact to undisturbed land and areas not already addressed with existing permits.

2) Potential funding sources to implement of project(s)

Specific for this planning grant request, Consumers Energy would seek funds for a future project through collaboration with the Michigan Public Service Commission and a potential future rate case.

Applicant must include a timeline and Gantt chart. Please attach as a separate document if necessary.

Bidder response:

Timeline for planning starts in December 2024 and continues through October 25. Prior to these planning efforts, a service territory wide assessment and initial community engagement will occur throughout 2024 to locate candidate sites and introduce the network geothermal technology to communities. At the start of the grant period, a site will be identified for detailed planning activities, which runs through geological assessment, energy modeling, thermal resource configuration and development of an implementation plan and cost benefit analysis. Planning work will complete on or before October 2025 with post community engagement occurring after. A Gantt Chart for these activities is shown on Attachment C.

	Finish
Identify and assess candidate sites	Dec-24
Establish stakeholder matrix	Dec-24
Site identification and conceptual network design	Feb-25
Engage community on assessment, technology and timeline	Feb-25
Engage key businesses with potential to serve as system anchors	Mar-25
Site-specific geological evaluation	Apr-25
Energy modeling	May-25
Thermal resource assessment	Jun-25
Infrastructure design	Aug-25
Implementation approach	Oct-25
Post-planning engagement with community	Jul-26

V-G Management Summary

(1) Describe management procedures that will be used by the organization to complete the proposed project.

(2) Describe the organization's quality control measures, including measures for ensuring compliance as well as eligibility determination. In your description, include information regarding separation of duties.

(3) Selected applicant(s) must provide fiscal control and financial accounting procedures that will

assure that grant funds will be accounted for and properly dispersed in a way that will allow the Issuing Office to clearly review and verify all grant related expenditures. Describe the organization's internal control policy:

- Identify the type of accounting system/software the organization will use to account for grant funds.
- Identify how duties will be separated.
- Describe how the organization will account for grant funds, i.e., will grant funds be placed in a separate bank account, will the grant funds be assigned a unique code(s) within the organization's overall accounting system. Ensure funds are maintained in a non-interest-bearing account.
- Indicate whether internal and external audits of the organization's operations are performed on an annual basis. Selected applicant(s) must provide a copy of the organization's most recent audited financial statement as well as a copy of the organization's most recent single audit as required by OMB Circular 200.36.

(4) Describe your agency's data security plan.

Bidder response:

1) Management procedures to be used include standard financial governance and project management practices. Financial governance refers to the review and potential approval of budgets, current year funding changes and financial management of contracts. Planning activities will also use standard project management practices referring the routine review of project status measured against their progress in achieving pre-defined metrics.

2) Consumers Energy is audited annually by a public accounting firm and has received unqualified opinions. Additionally, the Company has a separate public accounting firm, KPMG who performs internal audits annual based on a three-year risk assessment.

3) The Company will use our existing system SAP (System Applications and Products) to account for the potenial of grant funds. Proper internal controls, which would include segregation of duties, have been established and are reviewed as a part of the external and internal audits annually. The Company's management annually evaluates the effectiveness of its internal control over financial reporting and has deemed the controls effective. These controls are also audited annually by our external auditors. The Company will use various unique identifiers within our accounting system, SAP, to ensure all grant funds are properly accounting for and segregated from other funds. As noted above both external and internal audits are conducted on an annual basis. Below is a link to Consumers Energy's most recent financial filing.[5]

4) Consumers Energy has a comprehensive cybersecurity program aimed at securing our sensitive data and critical infrastructure. In addition, Consumers Energy has a privacy program aimed at ensuring data is handled appropriately at the company. Both programs include a number of technical controls, polices, procedures, standards and awareness activities.

V-H Personnel

Selected applicant(s) must be able to staff a project team that clearly possesses skill and experience relative to the project.

[5] Consumers Energy. (2024). Financial Information. Retrieved from CMS Energy Corporation - Investors - Financial Information - Annual Reports

1) Applicant(s) must identify the authorized contact person and key personnel to be involved with this project by name and title and provide a brief summary of their experience, qualifications, and the work to be performed.
2) If other organizations will be playing a role in the proposed project, provide sufficient background information that will give the MPSC a reasonable understanding of each organization's qualifications.
3) Include a detailed organizational chart including names, titles, and geographic location of all individuals that will contribute to the project.
4) If personnel or other organizations have signed a confidentiality agreement, attach a copy along with a list of personnel and the date that the confidentiality agreement was signed.

Bidder response:
The Planning Project will be staffed and managed with industry leading experts covering end to end details of the network geothermal technology. An organizational chart is shown in Figure 3 with qualifications for individuals described.

1) Authorized contact person: The following individual is the authorized contact person on behalf of Consumers Energy:

Neal Dreisig
Sr. Strategy Manager
989-239-8071
neal.dreisig@cmsenergy.com

2) Consumers Energy

- Neal Dreisig, Sr. Strategy Manager: Neal Dreisig is a Sr. Strategy Manager responsible for overseeing the decarbonization strategy for Consumers Energy's natural gas system. This includes renewable natural gas, hydrogen, carbon capture, electrification technologies and other alternative low carbon fuels. Prior to this, Neal held multiple roles within project management and generation operations. Neal holds a Bachelor of Science degree in construction management from Michigan State University and a Master of Science degree in Management from Colorado State University. Neal is also a certified Project Management Professional.

- Seth Epstein, System wide energy efficiency planning: Seth Epstein is Senior Product Manager at Consumers Energy where he leads the residential demand response product - AC Peak Cycling. Seth has deep knowledge of residential and commercial utility energy efficiency and demand response program design and delivery. He earned his master's degree in Natural Resources and Environment with a certificate in Industrial Ecology at the University of Michigan in Ann Arbor and his bachelor's degree in philosophy at St. Lawrence University in New York.

- Brian Snyder, Assessment Planning Engineer. Brian manages assessment planning, threat assignment, and risk analysis for the Transmission (gas pipeline) Integrity Management Program at Consumers Energy. This includes inline inspection, direct assessment and direct examination, and the analysis of probabilistic risk modeling to build forecasted work plans and budget. Previous experience includes HVAC design and energy modeling for commercial buildings specializing in healthcare applications. Brian has a Bachelors of Science, Mechanical Engineering, from the University of Michigan Dearborn, a licensed Professional Engineer in the State of Michigan, and a LEED Accredited Professional

- Dena Isabell, Community Engagement Manager. Dena leads statewide engagement internally and externally for major projects including coal plant decommissioning, gas pipeline projects, major hydro facility investments, significant electric reliability projects and all non-solar renewable energy development. Dena has an MBA from Ferris State University and a Bachelors in Biosystems Engineering from Michigan State University.

Salas O'Brien
Salas O'Brien is an engineering and technical services firm focused on advancing the human experience through the built environment. Salas O'Brien provides decarbonization expertise, leadership, and support to plan, design, and implement ground source heat exchange and solar photovoltaic systems that achieve exceptional operational cost savings and drastic carbon emissions reductions. To date, more than 400 geothermal projects are completed, providing over 84,000 tons of system capacity; and, over 100mW of installed solar, over 50mV of fuel cells, and over 200 central plant replacements and modernizations.

- Jeff Urlaub, Principal in Charge: Jeff has been responsible for the design and implementation of innovative, environmentally responsible solutions for clients across the United States. Jeff has more than 20 years of professional engineer experience in HVAC design, project management, design of engineered systems and mechanical services, with an emphasis in renewable energy, energy analysis and geothermal design.

- Rick Humphries, Project Manager: Rick is a mechanical engineer with a background in thermal systems design. Over the past decade he has focused on the creation of project companies to serve specific energy needs. Rick approaches projects in a holistic way, considering the application of technology, market drivers, and economic incentives to produce outcomes.

- Brian Urlaub, Geothermal Exchange Expert: Brian oversees Salas O'Brien's geothermal projects and is involved in procurement, design, and project management. He has 25 years of experience in the geothermal industry, beginning with installation and servicing in the field, then transitioning to design and sales. He is adept at working with clients to develop solutions that meet their goals while responding to site conditions, as well as schedule and budget expectations.

- Andy LaFerriere, Energy Analyst: Andy is an energy engineer with over a decade of experience in commercial, industrial, and institutional building analysis and campus energy master planning. His skillset ranges from basic screening of energy efficiency projects to advanced analysis, design, and optimization of large central plants, including an array of alternative energy technologies. Throughout his career he has played a key role in the development of some of the largest geothermal projects in the world.

NTH Consultants
NTH Consultants, Ltd. (NTH) provides practical and innovative solutions to a multitude of engineering challenges. A full service geotechnical, infrastructure and environmental engineering firm, NTH has been providing professional consulting services to public and private clients throughout the United States as a Michigan corporation since 1968. NTH Consultants' extensive knowledge of environmental regulations and conditions helps clients manage both state and federal environmental regulations for ecological, wetlands, habitat restoration, hazardous waste management, wastewater discharge, air emissions, hazardous materials storage, and health and safety issues.

- Craig Johnson, Senior Principal Engineer: Mr. Johnson offers 22 years of energy industry leadership, project management, and technical consulting, with 13 years of enterprise-wide utility operations, engineering, regulatory compliance, risk identification and mitigation, and overall program leadership. Within the utility roles, he had responsibility for all aspects of natural gas delivery

(production wells through customers burner tip), electric distribution operations and engineering, utility scale solar generation development and operation, and leadership of a coal-fired generation facility and associated landfill.

- Mark Hushebeck, Senior Project Geologist: Mr. Hushebeck has 37 years of experience in various geological aspects of geotechnical engineering, including: landslide evaluations and stabilizations, site feasibility, dams and levees, geologic mapping, field exploration, directional drilling studies, forensic evaluation and construction monitoring, land use planning, and preparation of bidding and specification packages. His experience includes large hillside residential developments, roads and highways, industrial / commercial structures, motor sports complex developments, geophysical and geotechnical instrumentation setup/monitoring, geologic field mapping, distressed single-family and multi-family residential building evaluations, resource potential evaluations and Level 1 environmental impact reports.

3) Organizational chart:

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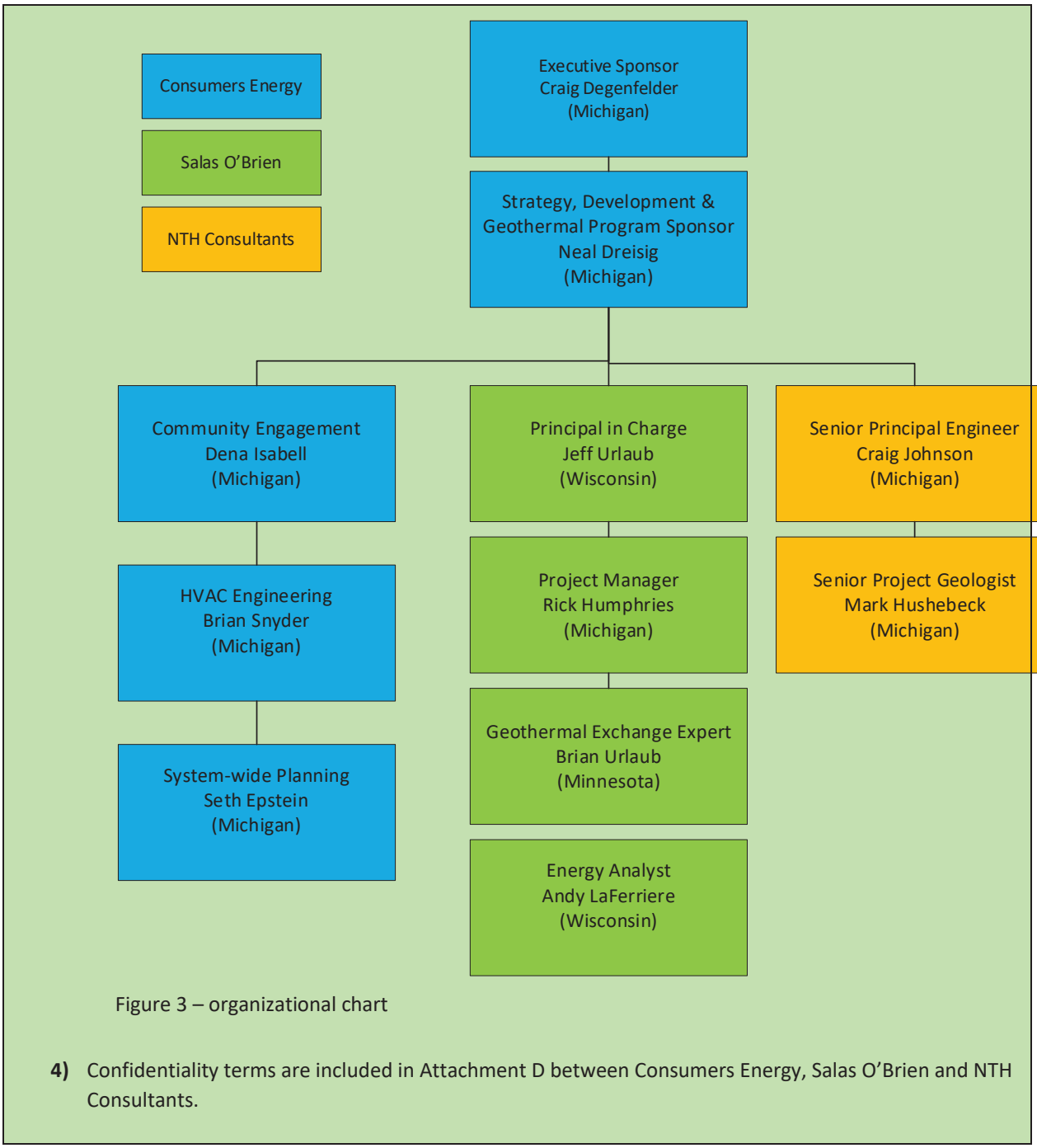

Figure 3 – organizational chart

4) Confidentiality terms are included in Attachment D between Consumers Energy, Salas O'Brien and NTH Consultants.

V-I Budget

To enable the MPSC to evaluate all project costs, applicant(s) will submit a proposed budget and corresponding budget narrative. Please see Attachment A for the required budget format. The budget and narrative must include only Renewable Energy and Electrification Infrastructure Enhancement and Development Grant Program funds in the budget; do not include matching, leveraged, cost share or any other type of supplemental funds. The budget narrative must identify the budget line item and number, provide a detailed description for each line, and include individual unit prices.

Selected applicant(s) will be required to provide supporting documentation for all grant expenditures incurred during the term of the grant. Accounting records must be supported by source documentation

including, but not limited to, general ledgers, time sheets, payroll registers, invoices, check copies and bank statements, or cancelled checks. Expenses will be verified based on actual expenditures incurred within the grant period that are supported by source documentation, not budgeted amounts.

1) **Budget Changes** – Any changes to the budget must be pre-approved by the MPSC Grant Administrator. Changes in the budget of less than 5% of the total line item amount, or $2,000 (whichever is greater), do not require a formal amendment; however, a revised budget should be submitted to the MPSC Grant Administrator for approval. The allowable transfer should be calculated as less than 5%, or $2,000 (whichever is greater), of the total line item that the funds are being transferred from.

   Cumulative changes in the budget equal to or greater than 5% of the total line item amount, or $2,000 (whichever is greater), may be permitted only upon prior review and written approval by the MPSC Grant Administrator. A formal grant amendment must be signed by both the Grantor and Grantee.

2) **Disallowed Costs** – Disallowed costs include but are not limited to the following: sick pay, vacation pay, holiday pay, bonuses, overtime, tuition reimbursement/remission, vehicle allowance, seminars, conferences, meetings, subscriptions, dues, and memberships.

3) **Administrative Costs** – Administrative costs cover expenses related to general administrative functions and coordination of functions and oversight directly related to the Renewable Energy and Electrification Infrastructure Enhancement and Development Grant Program administrative functions. Administrative costs should include costs of goods and services required for administrative functions of the program; travel costs incurred for official business in carrying out administrative activities or the overall management of the Renewable Energy and Electrification Infrastructure Enhancement and Development Grant Program; costs of information systems related to administrative functions; and contractual services related to sub-recipients or vendors that are solely for the performance of administrative functions. **Total direct administrative costs must be identified and labeled clearly.**

4) **Budget Requirements** – The proposed budget will display three (3) headings identified as the: Line Item, Budget Category, and Total Grant Request. The budget line items that need to be included, at a minimum, are listed below. The budget should reflect the best estimate of actual costs using whole numbers. Please refrain from using decimals or formulas. Refer to the budget example provided in Attachment A.

   - **Personnel** – In the budget, include the name, job title, and salary for each staff position to be paid for by the grant. Time sheets and payroll registers must be submitted for each staff position, and hours worked must be grant related. Fringe benefits may not exceed 35% of each employee's salary. Fringe benefits will be reimbursed based on actual expenditures per employee up to 35%, not on budgeted amounts. Allowable benefits include: health, dental, and optical insurance, employer-paid Social Security and Medicare tax, Michigan and Federal unemployment tax, and other miscellaneous fringe benefits (life insurance, long- and short-term disability insurance, worker's compensation, and retirement program contributions up to 4%). Within the budget narrative, applicant(s) must provide details on the organization's method of calculating fringe benefit expenses that will be charged to the grant including whether fringe benefits are calculated on an annualized basis or based on the length of the grant term.

     The budget narrative must include the number of weeks the individual will work on the grant; number of hours per week a full time employee of the organization is expected to work; a description of the work to be performed by each individual; the estimated hours to be worked; actual pay rate; the fringe benefit percentage being charged to the grant for each employee; the percentage of the employee's time allocated to the grant; whether each employee is salaried-exempt, salaried-non-exempt or hourly; and any other applicable information related to the individual's duties and responsibilities in connection with this grant.

     Individuals that are not on selected applicant(s)'s payroll, e.g., independent contractors, individuals

receiving a Form 1099, temporary workers, etc., must be placed under the Contractual Services budget category. Only employees on the selected applicant(s)'s payroll should be included in the Personnel budget category.

- **Supplies, Materials, and Equipment** – Specify item(s) and cost. The budget narrative should include the anticipated cost of each item, a detailed explanation of the item's purpose, and how it relates to the project being funded. Be as detailed as possible.

- **Contractual Services** – These services must be competitively bid. Individuals that are not on selected applicant(s)'s payroll, e.g., independent contractors, individuals receiving a Form 1099, temporary workers, etc., must be placed under **Contractual Services**. When competitive selection is not feasible or practical, the selected applicant(s) agrees to obtain the written approval of the MPSC Grant Administrator before making a sole source selection. Selected applicant(s) must provide a copy of contracts, memoranda of understanding or agreements signed by selected applicant(s) and contractors.

  Selected applicant(s) assumes responsibility to select subcontractors on a competitive basis. A minimum of three (3) bids must be solicited and proposals must include, at a minimum: (1) name of selected applicant(s), grant number, and grant period; and (2) the type, number, and description of projects as described in the proposal.

  Selected applicant(s) must provide the MPSC Grant Administrator with the solicitation, list of vendor responses (including amounts), and name of the selected vendor. Selected applicant(s) must maintain bids on file at their place of business according to Section II-H, Records Maintenance, Inspection, Examination, and Audit. The MPSC Grant Administrator will reserve the right to request a copy of all bids for services that are competitively bid.

  Selected applicant(s) must award the project to the lowest bid unless the MPSC Grant Administrator has given prior written approval for selection of a higher bid. Selected applicant(s) must provide a written justification for the selection of a higher bid. When awarding subcontracts, the selected applicant(s) must ensure that preference is given to products manufactured in or services offered by Michigan-based firms.

- **Other Expenses** – This category is solely for use by organizations charging a per-case fee for work performed by subunits or internal agencies within the organization that do not require a competitive bid, i.e. contract, memorandum of understanding or any other type of signed agreement.
- **Indirect Costs** – Indirect costs are costs not directly or specifically related to the grant program. Indirect costs are costs of administering the organization and must be spread over a number of products, services, or grant programs proportionately. Examples include office supplies and equipment, utilities, rent, maintenance and repair, insurance, accounting and bookkeeping services, and legal services. Non-cash expenses like depreciation, amortization, and depletion are not allowable indirect costs under this grant. **Total indirect costs must be identified, labeled clearly, and may not exceed an amount equal to 10% of the total direct costs.**

  Selected applicant(s) will be reimbursed for its proportional share of indirect costs. This means the MPSC should be allocated a portion of the selected applicant(s)'s indirect costs and not 100% of the organization's total indirect cost.

  Indirect costs should be displayed on the face of the budget on a single line item and the indirect rate should be rounded to six (6) decimal places. The budget narrative should contain a list of indirect costs, how the selected applicant(s) determined its indirect costs, and the percentage rate calculation for reimbursable indirect costs. Selected applicant(s) is not required to provide documentation supporting indirect costs; however, documentation verifying the costs must be retained by the selected applicant(s).

Indirect costs should be displayed on the face of the budget on a single line item and the indirect rate should be rounded to six (6) decimal places. The budget narrative should contain a list of indirect costs, how the selected applicant(s) determined its indirect costs, and the percentage rate calculation for reimbursable indirect costs. Selected applicant(s) is not required to provide documentation supporting indirect costs; however, documentation verifying the costs must be retained by the selected applicant(s).

5) **Grant Expenditure Guidelines** - To ensure efficient review and approval of grant expenditures, selected applicant(s) will be provided additional guidelines to assist with calculating and determining accurate and appropriate grant expenditures.

6) **Budget Subtotal** - Each budget category should have a subtotal displaying the total anticipated amount to be expended, and the budget should include a subtotal for total direct project costs and a sum of total project costs.

7) **Travel** - In the event that any necessary travel is anticipated, all expenses must be reflected in the applicant(s) hourly rate.

8) **Budget Modifications** - After grants are approved by the MPSC, modifications of proposals and budgets may be necessary. If the MPSC does not approve the total amount requested in the original proposal, selected applicant(s) will be required to submit a revised proposal, budget and budget narrative for the purpose of entering into a Grant Agreement. New line items to the revised budget are not allowed.

9) **Unexpended Grant Funds** - Selected applicant(s) assumes the responsibility of ensuring all unexpended grant funds are returned to the State of Michigan at the end of the grant period. Failure to do so may render selected applicant(s) ineligible for future grant awards and/or subject to legal action.

10) **Commingling Grand Funds** - Selected applicant(s) may not commingle grant award funds with current or future grant awards. All funding sources must be managed and accounted for separately.

Bidder response: Templates for the Budget and Budget Narrative are attached to the RFP Response document located on the Renewable Energy EIED webpage. In this bidder response, add any information not included in the Budget or Budget Narrative.

See below completed budget templates and narrative

V-J Current and Prior Experience and Funding Disclosure

Current and prior experience is important to the selection process. Proposals submitted by applicant(s) should include:

1) A description of the organization's experience in conducting the type of work proposed. Include current activities and activities for the previous ten years. Include project results.

2) If applicant(s) received a similar grant award from the State of Michigan in prior years for the type of project proposed, provide a summary of project accomplishments. Include a plan for addressing and resolving past problems.

3) Current funding source(s) and the level of funding for the current year and the previous ten years.

4) If additional dollars beyond these grant funds are being used for this project, indicate the source and amount.

5) If applying for a planning grant, identify potential funding sources (both internal and external) that

are secured to undertake construction of facilities or implementation of programs that a planning grant is intended to identify.

Bidder response:

1) Consumers Energy has assembled a team of highly experienced individuals and firms familiar with Michigan, its geological characteristics and demographics. This team includes Consumers Energy, Salas O'Brien and NTH Consultants.

Consumers Energy

Consumers Energy has over 100 years of experience with nearly all components of a network geothermal system including underground survey, drilling, energy efficiency, pipeline installation, right of way work, municipality coordination, and community engagement.

Salas O'Brien & NTH Consultants

Together Salas O'Brien are NTH Consultants are national leaders in the planning, design, and implementation of geothermal systems, central energy plants, and district energy systems, completing over 400 associated geothermal projects. Select project results are shown below.

Converting Ford's Dearborn Campus to District Energy

Ford Motor Company Dearborn Campus - Low Entropy Campus Master Plan and Central Utility Plant DEARBORN, MI, USA

Redeveloping six million gross square feet of research, engineering, and design facilities, Ford is upgrading to a modern district energy system. Salas O'Brien developed a Low Entropy Campus Master Plan and provided design services for the new Central Energy Plant and distribution systems. As the project prime, we managed all design disciplines including architectural services and structural engineering.

The facility includes: a 34 MW combined heat and power system with two Solar Titan 130s; a 16,000-ton chiller plant with heat pumps and high-efficiency cooling-only chillers; and, 40,000 ton-hours of thermal energy storage.

SERVICES
District Systems

COMPLETION YEAR
2020

CONSTRUCTION COST
Confidential

SIZE
100,000 square feet plant serving up to 9 million square feet of facilities

Results

- 40,000 ton-hours of thermal energy storage
- 16,000 ton chiller plant
- 34 MW combined heat and power system

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Scalable single-family neighborhood geothermal

Mattamy Homes, Berczy Glen MARKHAM, ON, CANADA

SERVICES
Geothermal and Renewables

SIZE
500,000 square feet; 312 Homes

COMPLETION YEAR
2024

PROJECT PARTNERS
Enwave Energy Corporation

Upon completion, Ontario's 327-home Berczy Glen development will be the first residential neighborhood in Canada to have its heating and cooling needs met by a central geothermal system. Salas O'Brien designed a net zero carbon system, 3.5 to 4 times more efficient than the conventional natural gas alternatives. Homeowners are expected to see 30-50% reduction in monthly utility bills.

The geothermal system consists of 170 vertical loop boreholes, 850' deep, distributed entirely under neighborhood streets in twelve pods, connected by a two-mile ambient water loop. Circulation pumps serving the loop and individual pods are housed in subgrade vaults, eliminating visible infrastructure.

The system will be maintained by Enwave Energy Corporation, demonstrating the feasibility of community-scale geothermal systems for Berczy Glen developers, Mattamy Homes.

80% reduction
in system carbon emissions

100% reduction
in household carbon emissions

U21806-MNSC-CE-0039_ATT 4

Evaluating conversion options

Xcel Energy Denver DENVER, CO, USA

SERVICES
District Systems

SIZE
120 Buildings

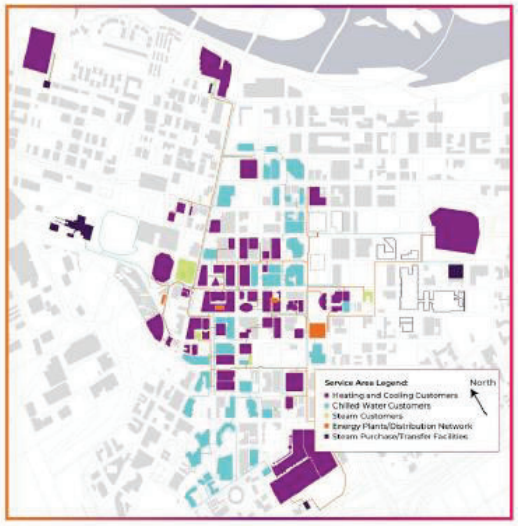
COMPLETION YEAR
In Progress

CONSTRUCTION COST
Confidential

Our team is currently performing a study on Xcel Energy's district steam system to review technological options, technical feasibility, and costs for converting to an ambient temperature heating/cooling system. Xcel would convert the existing steam system to an ambient temperature system and the second would utilize the chilled water system as an ambient temperature loop. The study will evaluate options to temper the ambient loop fluid including, the use of a community ground source heat exchanger, integration with the central steam plant, integration with the district chilled water system, use of system renewable electricity that would otherwise be curtailed, waste heat recovery, and thermal balancing that leverages customer loads.

The study will consider whether the steam system can serve existing service customers with a technology or technologies that align with state sector-based and state-wide GHG reduction targets as well as any requirements of Energize Denver. The study will provide a baseline of information on the technical feasibility and costs of the ambient temperature heating/cooling system.

Minneapolis



District energy solution to serve a new mixed-use development

Harmonia - Mixed Use Building MINNEAPOLIS, MI, USA

SERVICES
District Systems

SIZE
1,300,000 square feet

COMPLETION YEAR
Expected xxxxx

CONSTRUCTION COST
Confidential

The project through Cordia Energy aims to investigate a solution to serve a proposed development, dubbed "Harmonia" will cover a city block in downtown Minneapolis and will include two residential buildings with mixed use on the ground floor and one commercial office building.

Our team is developing a thermal profile based on current project concepts and programming to asses thermal needs of the future district and gain a preliminary understanding of geothermal system feasibility. We are evaluating three general geothermal system concepts which include open loop production and re-injection wells, open loop Darcy system, and closed loop vertical bore for ground heat exchange. A unique challenge is that below grade parking consumes the entire footprint of the property up to and below the sidewalks that border the city block, which would require both open and closed loop systems to be installed. While open loop looks like a promising solution from a thermal energy perspective; regulatory constraints will prevent locating well heads below grade without a variance. The variance will not likely be granted, thus eliminating the feasibility.

2) Consumers Energy received two grant awards in 2023 for the Swisslane and TDI Farm renewable natural gas Projects. These projects remain on schedule for in-service in 2026. Since award, both projects actively engaged the community achieving ordinance approval for the Swisslane Project to apply for a special land use permit. The Projects are managed through Consumers Energy's Enterprise Project Management Office, which requires due diligence and oversight reviews to highlight problems, incorporate lessons learned and ensure projects remain on track to achieve business case results.

3) Funding sources for the current year and previous 10 years is through our regulated rates to customers. The funding for this work is intended to be covered directly by the planning grant award.

4) The funding for this work is intended to be covered entirely by the planning grant award. Funding for work prior to the grant start date including community outreach and service territory wide assessments for potential network geothermal sites will use funds in a study-based balance sheet account until a capital asset or O&M expense is determined.

5) Specific for this planning grant request, Consumers Energy would seek potential funds to undertake construction of a potential project through collaboration with the Michigan Public Service Commission and a future rate case.

V-K Additional Information and Comments

Include in this section any other information that is believed to be pertinent but not specifically requested elsewhere in this RFP.

Bidder response:
N/A

V-L Certification of Proposal

Please sign the proposal including the following language:

I certify that all information contained in the proposal is true to the best of my knowledge and belief, and that the organization is in compliance and agreement with all sections of the Request for Proposal. Failure to comply with grant terms may result in termination.

Certified by: 2/12/2024
Date

Sarah Hollis Bowers
Vice President of Gas Engineering & Supply
Authorized Signatory Name and Title

Consumers Energy
Name of Organization

ATTACHMENT A - BUDGET

Renewable Energy and Electrification Infrastructure Enhancement and Development (EIED) Grant
Bidder Name: Consumers Energy Company
Submission Date: February 21, 2024

Please insert actual proposed budget amounts in the blank table provided below. Extra lines may be added as appropriate.

Line Item	Budget Category	TOTAL GRANT REQUEST
1	**Administrative Expenses**	
2	**Administrative Personnel (Grant Administration Staff)**	
3	*Salary*	
4	Employee 1 (Job Title) (___ Hrs. @ $xxxx/hour)	$ 0
5	Employee 2 (Job Title) (___ Hrs. @ $xxxx/hour)	$ 0
6	**Total Salary**	$ 0
7	*Fringe Benefits*	
8	Employee 1 (Job Title) (___ Hrs. @ $xxxx/hour)	$ 0
9	Employee 2 (Job Title) (___ Hrs. @ $xxxx/hour)	$ 0
10	**Total Fringe Benefits**	$ 0
11	***Total Administrative Personnel***	$ 0
12	**Administrative Supplies, Materials, and Equipment**	
13	General Office Supplies	$ 0
14	***Total Administrative Supplies, Materials, & Equipment***	$ 0
15	**Total Administrative Expenses**	**$ 0**
16	**Contractual Services**	
17	**Contractual Services Personnel Salary**	
18	*Salary*	
19	Employee 1 (Job Title)	$ 0
20	Employee 2 (Job Title)	$ 0
21	**Total Salary**	$ 0
22	*Fringe Benefits*	
23	Employee 1 (Job Title)	$ 0
24	Employee 2 (Job Title)	$ 0
25	**Total Fringe Benefits**	$ 0
26	***Total Contractual Services Personnel Salary***	$ 0
27	**Contractual Services Supplies, Materials, and Equipment**	
28	Supplies, Materials, and Equipment	$0
29	***Total Contractual Services Supplies, Materials, and Equipment***	$0
30	**Total Contractual Services Expenses**	**$0**

31	**Sub-contractual Services, Large Equipment, Customer Rebates, Other Direct Costs**	
32	**Sub-contractual Services**	
33	Vendor 1 – Salas O'Brien	$ 325,000
34	Vendor 2 – NTH Consultants	$ 100,000
35	Independent Contractor 1	$ 0
36	Independent Contractor 2	$ 0
37	***Total Sub-contractual Services***	$ 0
38	**Large Equipment Costs (Infrastructure Grants)**	
39	Type of Equipment	$ 0
40	***Total Large Equipment Costs***	$ 0
41	**Customer Rebates (Program Grants)**	
42	Payments to Residential Customers (___ @ $xxxx)	$0
43	Payments to Commercial Customers (___ @ $xxxx)	$0
44	***Total Customer Rebates***	$0
45	**Other Direct Costs**	
46	Other Direct Costs Detailed	$0
47	***Total Other Direct Costs***	$0
48	**Total Sub-Contractual Services, Large Equipment, Customer Rebates, Other Direct Costs Expenses**	**$425,000**
49	**Total Direct Cost**	**$ 425,000**
50	**Indirect Costs**	
51	*Indirect Cost (0.10) – May not exceed 10% of total direct costs.*	$ 0
52	***Total Indirect Costs***	**$0**
53	**TOTAL GRANT FUNDS REQUESTED**	**$ 425,000**

ATTACHMENT B – BUDGET NARRATIVE

The narrative below may be updated with the applicant's own line description as appropriate. If extra lines were added in the Budget Table, add them in the narrative as well. Include a budget narrative for each partnering organization or subcontractor working on the project.

1	**Administrative Expenses** Category Not Applicable (N/A)
2	**Administrative Personnel (Grant Administration Staff)** Category Not Applicable (N/A) In the event that any necessary travel is anticipated, all expenses must be reflected in the applicant(s) hourly rate.
3	*Salary* Category Not Applicable (N/A)
4	Employee 1 Name (Job Title) Category Not Applicable (N/A)
5	Employee 2 Name (Job Title) Category Not Applicable (N/A)
6	**Total Salary = $0** Category Not Applicable (N/A)
7	*Fringe Benefits (Fringe benefit for Employees should match named salary employees listed above)* Category Not Applicable (N/A)
8	Employee 1 Name (Job Title) Category Not Applicable (N/A) Fringe benefits for Employee 1 <Name> should equal not more than 35% of his/her grant-related salary. These fringe benefits include <list fringe benefits received by Employee 1>. The cash basis of accounting is used to calculate Fringe Benefit expenses applicable to the grant. Our organization will use the accrual basis of accounting method for all transactions in the general ledger. The approximate cost for this line item number is $0. *Note: Allowable fringe benefits include the following: Health, Dental, and Optical Insurance, employer- paid Social Security and Medicare Tax, Michigan and Federal unemployment tax, and other miscellaneous fringe benefits (i.e., life insurance, long-and short-term disability insurance, workers' compensation, and retirement program contributions up to 4%). Only include benefits the employee is actually receiving or is expected to receive. If each employee receives the same fringe benefit package, list the items under the first employee and refer to the line item where they are listed for each additional employee.*

9	Employee 2 Name (Job Title) Category Not Applicable (N/A) Fringe benefits for Employee 1 <Name> should equal not more than 35% of his/her grant-related salary. These fringe benefits include <list fringe benefits received by Employee 2>. The cash basis of accounting is used to calculate Fringe Benefit expenses applicable to the grant. Our organization will use the accrual basis of accounting method for all transactions in the general ledger. The approximate cost for this line item number is $0.
10	**Total Fringe Benefits = $0** Category Not Applicable (N/A)
11	***Approximate Total Administrative Personnel = $0*** Category Not Applicable (N/A)
12	**Administrative Supplies, Materials, and Equipment** Category Not Applicable (N/A)
13	General office supplies, for example paper and general office supplies, are estimated at $0. Category Not Applicable (N/A)
14	***Approximate Total Administrative Supplies, Materials, and Equipment = $0*** Category Not Applicable (N/A)
15	**Total Administrative Expenses = $0** *(Lines 6, 10, 14)* Category Not Applicable (N/A)
16	**Contractual Services** Category Not Applicable (N/A)
17	**Contractual Services Personnel Salary** In the event that any necessary travel is anticipated, all expenses must be reflected in the applicant(s) hourly rate. Category Not Applicable (N/A)
18	*Salary* Category Not Applicable (N/A)
19	Employee 1 Name (Job Title) Category Not Applicable (N/A)
20	Employee 2 Name (Job Title) Category Not Applicable (N/A)
21	**Total Contractual Services Salary = $0** Category Not Applicable (N/A)
22	*Fringe Benefits*

23	Employee 1 Name (Job Title) Category Not Applicable (N/A) The approximate cost for this line item number is $0. *Note: Allowable fringe benefits include the following: Health, Dental, and Optical Insurance, employer- paid Social Security and Medicare Tax, Michigan and Federal unemployment tax, and other miscellaneous fringe benefits (i.e., life insurance, long-and short-term disability insurance, workers' compensation, and retirement program contributions up to 4%). Only include benefits the employee is actually receiving or is expected to receive. If each employee receives the same fringe benefit package, list the items under the first employee and refer to the line item where they are listed for each additional employee.*
24	Employee 2 Name (Job Title) Category Not Applicable (N/A) The approximate cost for this line item number is $0.
25	**Total Fringe Benefits = $0** Category Not Applicable (N/A)
26	***Approximate Total Contractual Services Personnel Salary = $0*** Category Not Applicable (N/A)
27	**Contractual Services Supplies, Materials, and Equipment** Category Not Applicable (N/A)
28	Supplies, Materials, and Equipment includes <provide detailed description of supplies, materials, and equipment> and are estimated at $0. Category Not Applicable (N/A)
29	***Approximate Total Contractual Services Supplies, Materials, and Equipment = $0*** Category Not Applicable (N/A)
30	**Total Contractual Services Expenses = $0** *(Lines 21, 25, 29)* Category Not Applicable (N/A)
31	**Sub-contractual Services, Large Equipment, Customer Rebates, and Other Direct Costs**
32	**Sub-Contractual Services**

33	Vendor 1 Salas O'Brien. Services include consultation on site identification using criteria such as GDP, demographics, energy load diversity, current energy consumption and existing infrastructure; energy modeling to understand the effectiveness of energy sharing across users on the network; thermal resource assessment which includes initial design and configuration of the network; infrastructure planning which involves detailed mechanical and civil designs to support the network; energy and capacity assessments; implementation approach which involves a future project execution plan, capital cost estimate, cost of energy estimate, carbon reduction estimate, impacts and connections to existing buildings and work involved with public rights of way. Salas O'Brien will be actively engaged on in phases 1, 3, 4, 5 and 6. The first phase accounts for $25,000, while the remaining 4 phases estimated at $75,000 each. Total approximate cost for this line item is $325,000.
34	Vendor 2 NTH Consultants. NTH Consultants will perform Phase 2, the geological evaluation including test bores, soil testing, fluid testing and overall thermal conductivity testing. Total approximate cost for this line item is $100,000.
35	Independent Contractor 1 Category Not Applicable (N/A) Total approximate cost for this line item is $0.
36	Independent Contractor 2 Category Not Applicable (N/A) Total approximate cost for this line item is $0.
37	***Approximate Total Sub-Contractual Services = $425,000***
38	**Large Equipment Costs (Infrastructure Grants)**
39	Category Not Applicable (N/A) Total approximate cost for this line item is $0.
40	***Approximate Total Large Equipment Costs = $0*** Category Not Applicable (N/A)
41	**Customer Rebates (Program Grants)** Category Not Applicable (N/A)
42	Payments to Residential Customers (0 @ $0) Category Not Applicable (N/A) Total approximate cost for this line item is $0.

43	Payments to Commercial Customers (0 @ $0) Category Not Applicable (N/A) Total approximate cost for this line item is $0.
44	***Approximate Total Customer Rebates = $0***
45	**Other Direct Costs** Category Not Applicable (N/A)
46	Other Direct Costs Detailed Category Not Applicable (N/A) Total approximate cost for this line item is $0.
47	***Approximate Total Other Direct Costs = $0*** Category Not Applicable (N/A)
48	**Total Sub-Contractual Services, Large Equipment, Customer Rebates, and Other Direct Cost Expenses = $425,000** *(Lines 37, 40, 44, 47)*
49	**Total Direct Costs = $425,000** *(Lines 15, 30, 48)*
50	**Indirect Costs** Category Not Applicable (N/A)
51	Indirect Cost (0.1) Category Not Applicable (N/A) Indirect Costs account for expenditures that are unforeseen and are not considered part of direct costs. Provide a list of indirect costs, how the indirect costs are determined, and the percentage rate calculation for reimbursable indirect costs. This line item is not to exceed 10% (0.1) of the direct costs.
52	***Total Indirect Costs = $0***
53	**Total Grant Funds Requested (direct plus indirect costs) = $425,000**

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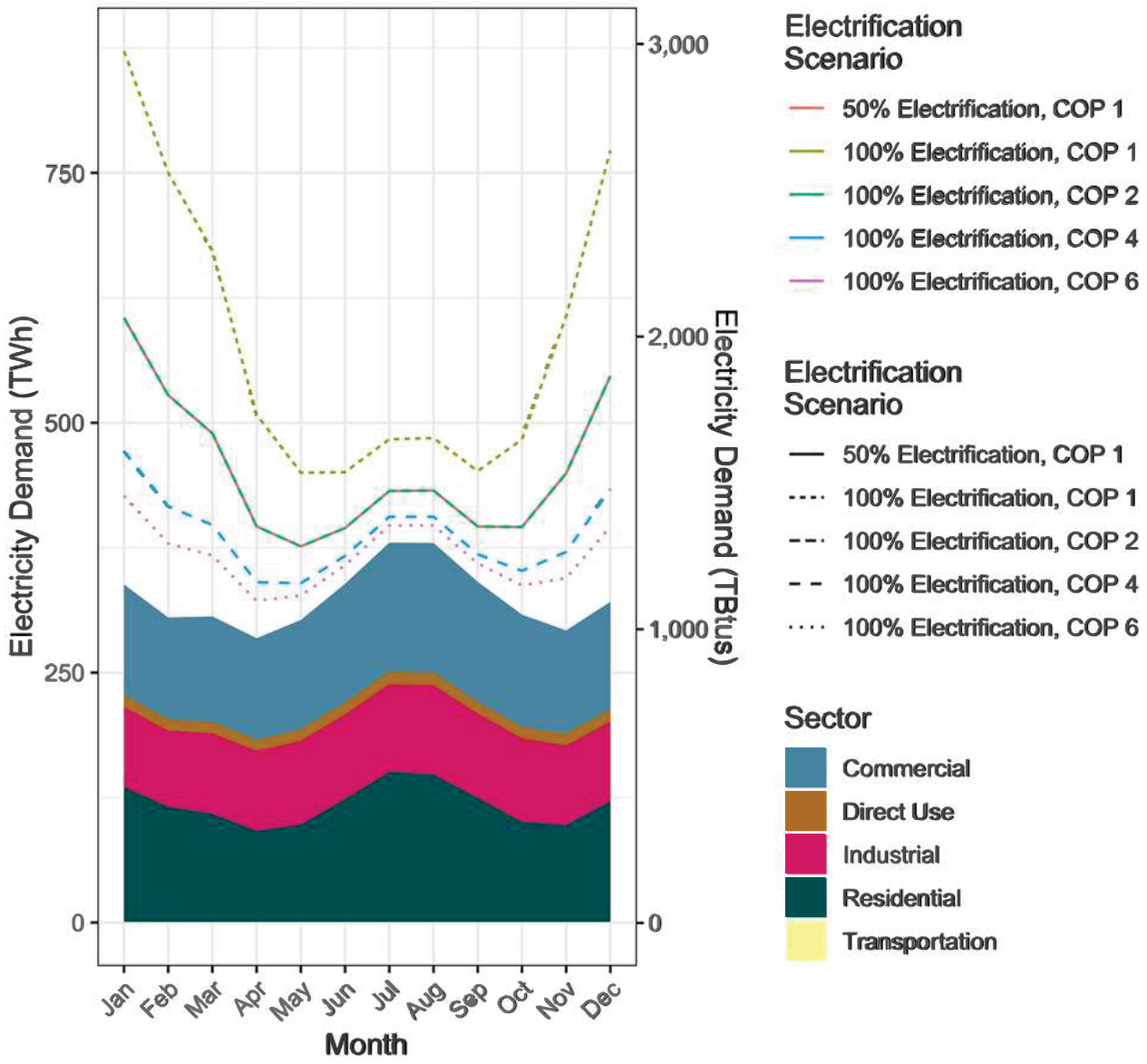

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Consumers Energy Count on Us®

CADMUS

2021 Cold-Climate Heat Pump Initiatives Evaluation Report

August 26, 2022

Presented to:

Consumers Energy

Joseph Forcillo

Director of Evaluation, Measurement & Verification

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Presented by:

Cadmus

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U21806-MNSC-CE-0573_Att 1

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Acronyms and Abbreviations

Acronym	Definition
AC	Air conditioner
AMI	Advanced metering infrastructure
ASHP	Air-source heat pump
CCHP	Cold-climate heat pump
CDH	Cooling degree hour
COP	Coefficient of performance
HDH	Heating degree hour
HSPF	Heating seasonal performance factors
MEMD	*Michigan Energy Measures Database*
NPS	Net promoter score
PMOs	Property owners and managers
SEER	Seasonal energy efficiency ratio
TMY3	Typical meteorological year version 3

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Executive Summary

In its March 5, 2020 Order Approving Settlement Agreement in Consumers Energy's *2020-2023 Energy Waste Reduction (EWR) Plan*, the Michigan Public Service Commission (MPSC) authorized the Company to invest in cold-climate heat pump (CCHP) initiatives for both income-qualified and non-income-qualified residential customers and business customers to test the efficacy, performance, and customer experience, among other factors. The Settlement Agreement[1] required the Company to submit an interim and final report delineating cold-climate heat pump (CCHP) initiative findings with the Company's 2020 and 2021 EWR Reconciliation filings, respectively. This report supplements the CCHP final report submitted as required by the March 5 Order and documents 2021 evaluation activities.[2]

The approved Settlement Agreement included both increased investment to support the income-qualified program performance metric associated with CCHP installations and a CCHP retrofit pilot initiative targeted to residential homes and businesses heated with electricity or heating fuels not regulated by the Michigan Public Service Commission, such as delivered propane or fuel oils. Given the challenges with implementing the CCHP initiatives, as well as unanticipated delays due to COVID-19, participation for income-qualified single-family and small commercial customers in 2021 occurred late in the year. This late participation has delayed the evaluation impact analysis for these two initiatives. All impact evaluation efforts will be completed in 2022 and the report will be filed in the case docket.

The main objective of these CCHP Initiatives was to demonstrate the potential for energy savings by replacing inefficient heating and cooling equipment with CCHPs. Consumers Energy targeted four distinct customer groups:

- Residential customers with electric or delivered fuel heating
- Income-qualified single-family customers with electric or delivered fuel heating
- Income-qualified multifamily customers with electric heating
- Small commercial customers with electric or delivered fuel heating

Consumers Energy designed its CCHP Initiatives to address both the supply and demand for CCHPs. The initiatives were implemented through Consumers Energy's existing residential, income qualified and small business product offerings. They aimed to strengthen trade allies' capabilities to install and service advanced heat pumps while increasing customers' awareness of and confidence in heat pumps as a viable, affordable, and environmentally friendly home heating source.

The CCHP Initiatives' incentives varied by customer type and ranged from $1,000 for market-rate customers to the full cost of installation for income-qualified and small business customers.

---

[1] Original settlement agreement: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000009hu1HAAQ at page 2
Settlement agreement amendment: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000CGUIcAAP

[2] Cadmus. 2020-2021 Cold-Climate Heat Pump Initiatives Final Report. May 18, 2022.

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Consumers Energy marketed the initiatives through participating contractors, who were familiar with heat pump technology and had been educated about the offering, as well as through mass marketing campaigns and other Consumers Energy network partners like Habitat for Humanity. Table 1 through Table 3 shows participation and investments through December 31, 2021, by customer group and year.

Table 1. 2020 and 2021 Cold-Climate Heat Pump Participation and Investment

	Residential Market Rate	Income Qualified		Small Commercial	Total
		Single-Family	Multifamily		
2020 - 2021 Target	50 [a, b]	160	558	25 [b]	**793**
2020 - 2021 Installations	53	179	663	26 [c]	**921**
Percentage of Target	106%	112%	119%	88%	**116%**
Total Investment	$579,297	$3,184,143	$3,664,670	$999,000	**$8,427,110**

[a] The original Settlement Agreement targeted 100 heat pumps. Per the end of July 2020 reforecast; this was adjusted to 50 heat pumps.
[b] While the income qualified targets are specific to each year and summed in this table, the residential market rate and small commercial targets represent the total adjusted targets for the two-year period.
[c] This is updated from the 2020–2021 Cold Climate Heat Pump Initiatives Final Report.

Table 2. 2020 Cold-Climate Heat Pump Participation and Investment

	Residential Market Rate	Income Qualified		Small Commercial [a]	Total
		Single-Family	Multifamily		
2020 Target	100 [b]	100	225	25	**450**
2020 Installations	5	78 [c]	276	0	**359**
Percentage of Target	5%	78%	123%	0%	**80%**
2020 Investment	$258,771	$1,447,290	$1,523,558	$225,204	**$3,454,823**

[a] The small commercial initiative had eight commitments with three customers at the end of 2020, but no completed installations.
[b] The original Settlement Agreement targeted 100 heat pumps. Per the end of July reforecast, this was adjusted to 50 heat pumps.
[c] Of the 78 heat pumps, 74 were installed for a large group of duplexes owned by one landlord. Duplexes are classified as single-family homes.

Table 3. 2021 Cold-Climate Heat Pump Participation and Investment

	Residential Market Rate	Income Qualified		Small Commercial	Total
		Single-Family	Multifamily		
2021 Target	50	60	333	25	**468**
2021 Installations	48	101	387	26 [a]	**562**
Percentage of Target	96%	168%	116%	112%	**120%**
2021 Investment	$320,526	$1,736,853	$2,141,112	$773,796	**$4,972,287**

[a] This is updated from the 2020-2021 Cold-Climate Heat Pump Initiatives Final Report.

In addition to persistent market barriers to the adoption of CCHPs documented in the first-year summary of pilots, the Settlement Agreement imposed eligibility restrictions for Consumers Energy CCHP initiatives, requiring heat pump systems to displace at least 50% of a customer's heating load from delivered fuels or electric resistance heating systems and limiting residential eligibility to primary residences only (i.e. secondary or vacation homes were ineligible).

Consumers Energy continued to encounter several challenges with encouraging heat pump adoption across all income levels and all residential and multifamily building types. These challenges resulted in lower participation than expected and are attributed to a lack of consumer awareness, difficulty identifying eligible customers, lack of contractor participation, and, in some cases, high incremental costs. Consumers Energy encountered fewer challenges with small business owners given that the Initiative covered the full installation cost of the CCHP, but Consumers Energy recognizes this is not a sustainable program option and expects to encounter similar challenges as the residential market when the incentive no longer covers the full equipment and installation cost for customers.

Despite these challenges, participants were generally satisfied with their experience and gave high satisfaction ratings for the overall performance of their new heat pump. Participants also reported better working equipment and increased comfort compared to their previous equipment. In addition, the Evaluation team's impact analysis for market rate and income-qualified multifamily customers show most participants will save energy, and in turn, money on their heating and cooling bills; however, the ranges of savings vary based on the heating fuel type of the replaced equipment. An engineering analysis for income-qualified single-family customers and metering analysis for small commercial customers is currently underway and will be completed by end of 2022.

Consumers Energy contracted with independent teams led by Cadmus and TRC to evaluate its respective residential and commercial program portfolios (referred to jointly as the Evaluation team throughout this report). The Evaluation team focused on providing Consumers Energy with the necessary details to inform later phases of the CCHP Initiatives and on monitoring early performance in 2021 to comply with the evaluation and reporting requirements in its Settlement Agreement.

Research Objectives

The Cadmus team focused our evaluation on providing Consumers Energy with the necessary details to inform later phases of promoting CCHPs. Following discussions with Consumers Energy's program management staff, the Cadmus team identified several research objectives regarding the evaluation.

Cadmus assessed four research objectives:

Assess the CCHP Initiatives' performance according to energy savings, customer satisfaction, impacts to customer bills, operational issues, and customer comfort.

Understand market readiness to adopt heat pump technology on a large scale and learn about the challenges of installing CCHPs.

Determine current limitations in the CCHP supply chain and their potential implications for the CCHP Initiatives.

Understand how CCHPs impact low-income customers and property managers who own income-qualified housing on non-energy factors such as changes in energy bills, heating and cooling equipment operation, and comfort levels.

Research Approach

Starting in 2021, the Evaluation team conducted several research and evaluation activities:

- Interviews with Consumers Energy CCHP Initiatives managers and implementation contractors (n=7)
- Interviews with HVAC contractors, distributors, and CCHP manufacturers (n=18)
- Billing analysis, engineering reviews, site visits, and metering for commercial participants (n=9)
- Surveys or interviews with Initiative participants and property owners (n=51)
- Residential Market Rate Participant Engineering Analysis (n=51)
- Multifamily and Income Qualified Billing Analysis (n=77 participants and 112 comparison buildings)

Participation was limited across all initiatives. This meant there were small populations to survey, interview, and perform billing analysis activities even using the census of participants. Therefore, the generated results, in most cases, are not statistically significant and while the evaluation team has made some conclusions and recommendations in this report, there is remaining uncertainty about the technology performance and market potential of CCHPs in Michigan. In addition, participation for small business customers occurred later in 2021, which delayed the metering of small business CCHPs.[3] Results from this activity will be prepared for Consumers Energy in Q4 2022.

Report Organization

We organized this report as follows:

- Summary of Key Findings, Conclusions, and Recommendations
- Contractor, Distributor, and Manufacturer Findings
- Residential Market Rate Initiative Findings
- Income Qualified Multifamily Initiative Findings
- Commercial and Industrial Cold-Climate Heat Pump Pilot Findings
- Appendices
  - Appendix A: Survey and Interview Methodology and Details
  - Appendix B: Impact Analysis Methodology and Details
  - Appendix C: Consumers Energy Heat Pump Market Rate Customer Survey
  - Appendix D: Consumers Energy Heat Pump Property Owner and Manager Interview Guide
  - Appendix E: Consumers Energy Heat Pump Multifamily Tenant Survey Guide
  - Appendix F: Consumers Energy Heat Pump Commercial Interview Guide
  - Appendix G: Consumers Energy Heat Pump Contractor Interview Guide
  - Appendix H: Consumers Energy Heat Pump Manufacturer and Distributor Interview Guide

[3] Initial impact analysis for commercial customers is reported in " 2021 Cold Climate Heat Pump Pilot Impact Evaluation Results Memo submitted to Consumers Energy by TRC. Updated cooling savings will be provided at the conclusion of additional metering in November 2022.

Summary of Key Findings, Conclusions, and Recommendations

This section presents the Evaluation team's key research findings, conclusions, and recommendations associated with the four cold-climate heat pump (CCHP) research objectives, which informed our evaluation tasks. The remaining chapters of this report provide further explanation of these findings and support for our conclusions and recommendations.

Key Findings and Recommendations

CONCLUSION 1. There is low and varied awareness of cold-climate heat pumps by homeowners, property owners and their tenants, and commercial businesses and even lower awareness that Consumers Energy offers cold-climate heat pump rebates.

Participants' awareness of CCHPs and Consumers Energy rebates was largely driven by HVAC contractors and Consumers Energy. However, awareness varied among contractors and within the territories they served. Where contractors were aware of CCHPs, they were a driving force of information dissemination about heat pumps and Consumers Energy rebates for both residential and commercial customers.

TRADE ALLIES: Contractors' overall awareness of heat pump technologies was largely correlated with the heating fuels used by their customer base. Contractors serving rural populations (where delivered fuels are more common) were more familiar with ducted heat pump systems, while contractors serving urban populations (where electric resistance heating is more prevalent) were more familiar with ductless heat pump systems. Contractors indicated that Consumers Energy could be instrumental in driving awareness of heat pump technologies, citing the success of the campaigns used to promote smart thermostats.

MARKET RATE: Most Residential Market Rate pilot participants reported being familiar with CCHPs before deciding to purchase one for their home (eight of nine), but few (three of nine) were aware that Consumers Energy provided heat pump rebates. While CCHP rebates were new in 2020, respondents' awareness of heat pumps came primarily from contractors, with about half (five of nine) indicating that a contractor had recommended a heat pump before they learned about and applied for the Consumers Energy heat pump rebate. A small number of participants (two of nine) heard about the rebate through Consumers Energy email communications.

INCOME QUALIFIED MULTIFAMILY: Multifamily property owners and managers were generally aware (31%, or n=10 of 32) of CCHPs prior to being approached by Consumers Energy, though they were not aware of Consumers Energy incentives until their involvement. However, the property owners and managers' tenants reported a lack of knowledge regarding heat pumps, with 66% of tenant respondents (n=21 of 32) saying they did not know about CCHPs, and half saying they were not aware that there was a CCHP installed in their apartment at the time of the survey. Of the half that were aware of the heat pump installation, 56% (n=9 of 16) did not know that Consumers Energy was involved in the project.

COMMERCIAL: Only two out of seven interviewed commercial respondents were familiar with cold-climate heat pump technology prior to participation. Those who had heard of cold-climate heat

pumps were unaware of the advancements in technology that made heat pumps more feasible for regions, like Michigan, with very cold winters. After learning about the new cold-climate heat pumps and Consumers Energy's pilot, most respondents were motivated to participate, but still held reservations about performance during the winter, prompting some to ask to keep their old heating system as a back-up.

RECOMMENDATIONS

High Priority: Identify opportunities for Consumers Energy to promote the cold-climate heat pump technology and incentives. Consider providing materials, such as one-page initiative summaries, for distributors to leave with contractors during their interactions. Continue to promote cold-climate heat pumps through events like the Annual Trade Ally Kickoff or identify larger distribution events or trainings where Consumers Energy can interact with trade allies.

High Priority: Increase contractor and customer education of cold-climate heat pump benefits and technology. Consider increasing the promotion of cold-climate heat pumps through planned marketing campaigns (such as bill inserts and online advertising) and through cross-program promotions.

CONCLUSION 2. Because natural gas is the predominate heating fuel in Michigan, and current Michigan Public Service Commission policy limits fuel-switching, there are limited cost-effective cold-climate heat pump installation opportunities. This contrasts with other states such as Maine and Vermont where a higher percentage of homes use more costly heating fuels such as propane and oil and where state policies incentivize fuel-switching.

TRADE ALLIES: While demand is increasing, trade allies reported that multiple barriers have limited demand for CCHPs in Michigan compared to other states. Manufacturers and distributors noted that awareness of and affinity for CCHPs among contractors varied and some maintain the belief that heat pumps are not effective in cold climates. Contractors and distributors also reported that increased customer awareness would help increase adoption; however, the cost of new CCHPs remains prohibitive. A homeowner likely needs to financially benefit from switching to a CCHP to be interested, but the lifecycle cost of a new CCHP compared to alternative heating technologies supplied by natural gas (the predominate heating fuel in Michigan) likely does not financially benefit the homeowner at a time when natural gas rates are low. Contractors acknowledged this fuel-switching challenge and said that even when they identify a potential cold-climate heat pump customer, there are few tools available for the contractor or customer to make accurate projections of the total system lifetime cost savings.

MARKET RATE AND COMMERCIAL CUSTOMERS: During 2021 and 2022, the Michigan Public Service Commission allowed Consumers Energy to target market rate and commercial customers who receive non-regulated fuels and those with electric heating systems. Consumers Energy's *2018 Residential Appliance Saturation and Home Characteristics Study* found that approximately 82% of customers in single-family homes across Consumers Energy's natural gas, electric and combination fuel

service territory heat their homes with natural gas, while 4% use electric heat and 14% use another source such as propane, fuel oil, or wood. This heating fuel distribution creates a significant challenge with identifying homeowners and businesses that may be eligible for a CCHP under the current regulatory rules (i.e., heat their homes or buildings with electric or distributed fuels), and limits market potential. Of the residential market rate participants for which baseline analysis was conducted (n=51), the majority (59%) used propane or oil, while 31 % used electric heat and 10% used natural gas heat prior to installing their heat pump[4].

Four of the seven commercial respondents interviewed discussed wanting to move away from using propane, and two of the respondents were motivated to participate in the pilot specifically so they could stop using propane. While respondents appreciated the opportunity to move from propane to electric heating, it is unclear whether Consumers Energy can continue with this targeted approach beyond the pilot phase. Future negotiations between the Michigan Public Service Commission and Consumers Energy and its stakeholders will determine whether Consumers Energy can continue to rely on this targeted approach in future initiative cycles.

RECOMMENDATIONS

High Priority: Because contractors reported that it is not always simple to determine when cold-climate heat pumps are economically more beneficial than traditional equipment, provide them with sales tools, such as a cost-effectiveness calculator, that can assist them in identifying when a cold-climate heat pump makes financial sense for their customers.

Low Priority: Promote the space cooling benefits associated with a cold-climate heat pump. Cold-climate heat pumps are a good option to add cooling where there was not previously a whole-home space cooling system or where the cold-climate heat pump can replace inefficient central air conditioners and room air conditioners.

CONCLUSION 3. Participants were generally satisfied with their experience and gave very high ratings for the CCHP Initiatives offering. However, multifamily tenants' satisfaction was split, largely based on whether the tenant received education on how to operate the new equipment.

MARKET RATE: Market rate customers gave high satisfaction ratings, with all nine respondents giving a rating of 8 or higher for their overall experience with the heat pump. In addition, market rate customers were highly likely to recommend the heat pump to a friend (with a net promoter[5] score of +89).

[4] Consumers Energy excluded most customers that used natural gas for space heating from the CCHP initiative, but a small number of participants recruited by contractors used natural gas prior to installation of the CCHP.

[5] The net promoter score is expressed as an absolute number between -100 and +100 that represents the difference between the percentage of promoters (respondents giving a rating of 9 or 10) and the percentage of detractors (respondents giving a rating of 1 to 6).

INCOME QUALIFIED MULTIFAMILY: The three interviewed income qualified multifamily property owners and managers provided an average rating of 9.5 (on a 10-point scale) for their satisfaction with the CCHP Initiatives and their likelihood to recommend heat pumps to a colleague. The property owners and managers also rated their likelihood to adopt similar CCHP equipment in their other properties as a 9.0 on a 10-point scale.

Income-qualified multifamily tenants (n=23 of 32) were *very satisfied* with their CCHP experience, and generally felt that the heat pumps provided improved winter heating and summer cooling comfort. Multifamily tenant participants gave an average rating of 8.7 for their overall experience with the heat pump, though some may not have been aware of their heat pump until they were contacted for the survey. Respondents also gave an average rating of 8.8 regarding summer comfort and 7.9 regarding winter comfort. However, tenants' willingness to recommend Consumers Energy was dependent on the level of communication and instruction provided to them regarding equipment operation. Tenants who provided verbatim feedback around lack of instruction were more likely to provide a lower overall net promoter score (averaging +13) than those who received instructions (averaging +50). Similarly, tenants who reported that the installer did not set up their heating and cooling schedule were also more likely to provide a lower overall net promoter score (averaging +10) than those who had the installer set up a schedule (averaging +67).

COMMERCIAL: Commercial participants rated their overall satisfaction with the CCHP Initiatives as an average of 9.9 out of 10, and 86% (six out of seven interviewees) strongly agreed that Consumers Energy made it easy to participate in the initiative.[6] In follow up interviews with participants, four out of five interviewees reported being satisfied with their heat pump's performance during the winter.[7]

CONCLUSION 4. Some participants received a new thermostat with their CCHP. Participants who received a new thermostat had varied knowledge about how to use it to optimize operation of their heat pump and some could have benefitted from additional instructions and training.

MARKET RATE: Seven of the nine residential market rate participants had a programmable or smart thermostat, while two reported having a non-programmable thermostat. Of those who had a programmable thermostat, only two programmed temperature setbacks. Despite most having thermostat programming capability, four of nine tended to adjust the temperature manually.

INCOME QUALIFIED MULTIFAMILY: Only three income qualified multifamily respondents could confirm with certainty that the contractor set up a heating and cooling schedule for their heat pump. These three participants also confirmed that the heating and cooling schedule set up by the

[6] Commercial participants were interviewed prior to experiencing a full heating season and some respondents listed this uncertainty about how the equipment would perform during the heating season as a reason for not giving a higher satisfaction rating for their heat pump, though the average rating was still 9.3 out of 10.

[7] The one respondent who was displeased, noted that the heat pump took a while to turn on, they often felt a cool breeze that was discharged directly onto an employee, and they had to adjust their thermostat higher than usual in order to achieve their preferred temperature.

contractor was still in operation. Only 25% (n=8) reported receiving instructions or documentation about the heat pump or use of their thermostat with the heat pump.

COMMERCIAL: Most respondents needed additional time to learn how to use their new thermostats and a few had minor issues operating their heat pumps. While most respondents did not have any problems with their new heat pumps, some (43%; n=3) reported that learning how to use their new thermostat was the most challenging aspect of their new equipment. Two respondents (29%) also reported needing a contractor's assistance with minor issues related to operating their heat pump. These minor issues included resolving an installation error and adjusting the cooling so that the air temperature was reaching the thermostat's temperature setpoint. Another finding from the follow up interviews was that some customers needed additional support understanding the controls and settings of the heat pumps to maximize the value, especially when sites have overlapping building controls with multiple heating units.

RECOMMENDATION

High Priority: Consider increasing follow up communications and support after the installation to ensure participants understand their new technology. Sending follow-up emails with resources and providing high-touch support after the installation engenders a positive equipment experience, which is critical for word-of-mouth testimonial marketing. Encourage contractors to provide set up and programming instructions and provide contractor training to ensure they are familiar with different types of thermostats and systems.

CONCLUSION 5. Participants reported better working equipment and increased home and business comfort levels after the installation of their CCHP.

MARKET RATE: Most market rate participants surveyed (seven of nine) said their home was more comfortable after installing the heat pump. The nine respondents rated their comfort level as 9.1 on average during the summer, with a slightly lower rating of 8.6 (n=5) during the winter. None of the respondents indicated any concerns with the heat pump's ability to heat to a preferred comfort level. Five respondents also mentioned improved heating and cooling distribution across sections of the home.

INCOME QUALIFIED MULTIFAMILY: Income-qualified multifamily tenants said their homes were as comfortable with the CCHPs as before (43%), with one-quarter reporting increased comfort levels. A few tenants said their home was too hot or too cold after the heat pump installation. Property owners and managers indicated that tenant comfort was a key decision factor to install CCHPs.

COMMERCIAL: Customers were very satisfied with heat pump performance overall , though three interviewees (43%) reported some minor initial issues with their heat pumps, including one who said it did not cool down to the expected temperature and two who had issues with the installation that required a contractor to fix.

RECOMMENDATION

Medium Priority: Promote the increased home and business comfort that cold-climate heat pumps can provide during both the heating and cooling seasons. Developing and using home and business testimonials could be an effective way Consumers Energy can promote the benefits of cold-climate heat pumps such as increased comfort, lower energy bills, and for some, the addition of space cooling.

CONCLUSION 6: Distributors generally had heat pump inventory on hand, so delivery times were either not impacted or were only impacted temporarily by manufacturing delays.

While manufacturers and distributors reported manufacturing delays as a result of COVID-19, as well as on-going transportation delays, distributors generally reported having sufficient stock on hand to meet current demand. Only one distributor reported a delay (6 to 8 weeks) in getting equipment to the customer. Note that custom equipment was generally not discussed in the interviews with manufacturers and distributors, and it is possible that timelines for custom equipment could be different. It is also worth noting that the manufacturer and distributor interviews were conducted in April of 2021, and the factors influencing supply chains may have changed since this time.

CONCLUSION 7: Most residential market rate and income-qualified Multifamily participants realized heating and cooling utility bill savings after the installation of their CCHP. However, bill savings largely depends on heating fuel prior to the heat pump installation, as well as how the homeowner used their new equipment.

MARKET RATE: The majority of market rate participants replaced propane heating systems (51%), followed by electric heating (31%), natural gas heating (10%), and fuel oil heating (8%).[8] Based on engineering estimates, market rate participants who replaced propane or electric heating systems will realize approximately $910 to $1,680 in heating and cooling savings per year[9]. The five homes that previously heated with natural gas will likely see an increase in their utility bill of $450 per year on average due to the higher cost of electricity compared to natural gas; also, four of the five homes did not have existing central air conditioning, which means they will add electrical load in the summer.

INCOME QUALIFIED MULTIFAMILY: Income-qualified multifamily tenants, even though retaining their original baseboard heating systems, experienced annual savings of 896 kWh, which translates to approximately $147 in annual bill savings. Most of the savings (93%) were realized during the heating season (largely October-April). These savings during the heating season were equivalent to approximately 23% of baseline weather-sensitive electric heating use. Income qualified multifamily tenants experienced lower than anticipated savings attributable to the heat pumps because they continued use of their baseboard heating systems, consistent with other recent evaluation findings.

[8] At the time of conducting the engineering analysis the evaluation team had a sample of 51 CCHP installations.

[9] Based on fuel costs at the time of the analysis in January 2022.

INCOME QUALIFIED SINGLE FAMILY: Due to low participation and delays due to COVID, the Income Qualified Single-Family Impact analysis will be completed in 2022. The Evaluation team is currently conducting an engineering analysis of the impacts for the income-qualified single-family installations, relying on MEMD parameters and assumptions collected from customers such as home vintage, presence of central cooling, equipment efficiencies, tonnage, and other data. The analysis will be completed later in 2022 and filed in the case docket.

COMMERCIAL: Because participation in the small business pilot occurred later in 2021, the impact evaluation was delayed. The impact evaluation is based on metered data, and TRC is keeping the meters in place to collect data for at least one complete heating season and one complete cooling season for each site.[10] The results of the heating season impact analysis are presented in a separate memo that is included in the filing of 2021 studies made on August 31, 2022.[11] Metering for the 2022 cooling season is still in progress as of the writing of the report, and analysis will take place in later in 2022.

RECOMMENDATIONS

High Priority: Provide multifamily property owners who had cold-climate heat pumps installed with information for how continued use of baseboard heating systems will minimize the tenant's ability to achieve the highest potential heating, and cost savings.

High Priority: Provide multifamily property owners with handouts they can distribute to tenants with simple operational instructions to ensure all new tenants understand how to operate their heat pump systems. Additional follow up and coordination with maintenance staff to review proper operations would ensure persistence of heat pump savings.

High Priority: If the Michigan policy on fuel switching should change, natural gas heating customers should be screened prior to approval to ensure the heat pump has potential to reduce energy bills.

Table 4 shows the Evaluation team's conclusion for each research objective outlined above.

[10] Metering analysis was performed for 22 CCHP installations.

[11] TRC. 2022. C&I 2021 Cold Climate Heat Pump Pilot Impact Evaluation Memo

CADMUS

Table 4. Research Objective Mapping

Conclusion	Research Objective			
	1. Assess Cold-Climate Heat Pump Initiative Performance	2. Understand Market Readiness and Challenges	3. Determine Current Supply Chain Limitations	4. Understand Impacts on Low-Income Customers
There is low and varied awareness of cold-climate heat pumps by homeowners, property owners and their tenants, and commercial businesses and even lower awareness that Consumers Energy offers cold-climate heat pump rebates.		✓		
Because natural gas is the predominate heating fuel in Michigan, and current Michigan Public Service Commission policy limits fuel-switching, there are limited cost-effective cold-climate heat pump installation opportunities. This contrasts with other states such as Maine and Vermont where a higher percentage of homes use more costly heating fuels such as propane and oil and where state policies incentivize fuel-switching.		✓		
Participants were generally satisfied with their experience and gave very high ratings for the Cold-Climate Heat Pump Initiatives offering. However, multifamily tenants' satisfaction was split, largely based on whether the tenant received education on how to operate the new equipment.	✓			✓
Some participants received a new thermostat with their cold-climate heat pump. Participants who received a new thermostat had varied knowledge about how to use it to optimize operation of their heat pump and some could have benefitted from additional instructions and training.		✓		
Participants reported better working equipment and increased home and business comfort levels after the installation of their cold-climate heat pump.	✓			✓
Distributors generally had heat pump inventory on hand, so delivery times were either not impacted or were only impacted temporarily by manufacturing delays.			✓	
Most residential participants realized heating and cooling utility bill savings after the installation of their cold-climate heat pump. However, bill savings largely depends on heating fuel prior to the heat pump installation, as well as how the homeowner used their new equipment.	✓			✓

Recommendation Priority

To assist Consumers Energy in prioritizing the actions needed to address these recommendations, the Evaluation team organized each evaluation recommendation by topic and prioritized them based on the following definitions.

- ***High Priority:*** The evaluation revealed compelling and conclusive data on a concern or a current initiative strength that are likely to have a significant impact on customer satisfaction, achievement of participation goals, or initiative savings if not addressed or maintained.
- ***Medium Priority:*** The evaluation revealed data that are inconclusive and require additional investigation or the issue is likely to have a moderate impact on initiative effectiveness or efficiency.
- **Low Priority:** The issue is likely to have little impact on initiative effectiveness or efficiency.

Table 5 lists the CCHP initiatives evaluation recommendations.

Table 5. Summary of Heat Pump Pilot Recommendations and Priorities

Priority	Summary of Recommendations
High Priority	Identify opportunities for Consumers Energy to promote the Cold-Climate Heat Pump technology and incentives. Consider providing materials, such as one-page initiative summaries, for distributors to leave with contractors during their interactions. Continue to promote cold-climate heat pumps through events like the Annual Trade Ally Kickoff or identify larger distribution events or trainings where Consumers Energy can interact with trade allies.
	Increase contractor and customer education of cold-climate heat pump benefits and technology. Consider increasing the promotion of cold-climate heat pumps through planned marketing campaigns (such as bill inserts and online advertising) and through cross-program promotions.
	Because contractors reported that it is not always simple to determine when cold-climate heat pumps are economically more beneficial than traditional equipment, provide them with sales tools, such as a cost-effectiveness calculator, that can assist them in identifying when a cold-climate heat pump makes financial sense for their customers.
	Consider increasing follow up and support after the installation to ensure participants understand their new technology. Sending follow-up emails with resources and providing high-touch support after the installation engenders a positive equipment experience, which is critical for word-of-mouth testimonial marketing. Encourage contractors to provide set up and programming instructions and provide contractor training to ensure they are familiar with different types of thermostats and systems.
	Provide multifamily property owners who had cold-climate heat pumps installed with information for how continued use of baseboard heating systems will minimize the tenant's ability to achieve the highest potential heating and cost savings.
	Provide multifamily property owners with handouts they can distribute to tenants with simple operational instructions to ensure all new tenants understand how to operate their heat pump heating systems. Additional follow up and coordination with maintenance staff to review proper operations would ensure persistence of heat pump savings.
	If the Michigan Public Service Commission policy on fuel switching should change, natural gas heating customers should be screened prior to approval to ensure the heat pump has potential to reduce energy use.
Medium Priority	Promote the increased home and business comfort that cold-climate heat pumps can provide during both the heating and cooling seasons. Developing and using home and business testimonials could be an effective way Consumers Energy can promote the benefits of cold-climate heat pumps such as increased comfort, lower energy bills, and for some the addition of space cooling.
Low Priority	Promote the space cooling benefits associated with a cold-climate heat pump. Cold-climate heat pumps are a good option to add cooling where there was not previously a whole-home space cooling system or where the cold-climate heat pump can replace inefficient central air and room air conditioners.

Contractor, Distributor, and Manufacturer Findings

Consumers Energy launched the CCHP initiatives just prior to the start of the COVID-19 pandemic, which as reported by Consumers Energy staff, created unique challenges such as long delays in project timelines due to back-ordered equipment. In addition, trade ally participation was low, with only one trade ally completing the vast majority of installations across these offerings in the early months of the initiative. To determine the sources of these barriers and understand the challenges associated with adopting CCHPs in Consumers Energy's service territory, the Evaluation team interviewed eleven contractors, two manufacturers, and five distributors involved in the installation, production, and distribution of CCHPs in Michigan.

Contractors' awareness and perceptions of CCHPs varied, and a contractor's interest in heat pump technologies in general depended largely on the availability of different heating fuels in their service territories. Contractors in rural areas, where delivered fuels are more common, had more awareness of and a greater affinity for ducted systems and heat pumps in general. Contractors in urban areas had more awareness of ductless systems, but overall lower levels of familiarity with and affinity for heat pump technologies.

Among all contractors, the pervading theme regarding CCHPs (and heat pumps in general) is that of uncertainty. In order to confidently promote heat pump technologies, contractors must be able to determine the operating cost of the equipment compared to a customer's existing equipment. Currently, there are no readily available tools that allow contractors to accurately model and compare the energy consumption of a heat pump to other heating sources; combined with the comparatively higher up-front cost of heat pumps, this inability to accurately model potential energy savings commonly makes heat pumps a non-starter. Furthermore, several contractors expressed a hesitancy to promote electric heating sources to their customers, as they perceived the price of electricity to be less static and more prone to price increases than other fuel sources. Additionally, some contractors were unaware that CCHPs were effective in cold climates. The confluence of uncertainty around CCHPs is commonly too significant of a barrier for contractors to abandon the status quo of a like-for-like equipment replacement.

Although there were manufacturing and transportation delays, distributors reported having stock on hand that was sufficient to meet current demand. Manufacturers and distributors noted that some contractors maintained the belief that heat pumps were not effective in cold climates (a finding that may be correlated with a contractor's location, given that the contractor interviews found that contractors in urban areas were less aware and less in favor of heat pumps compared to those in rural areas). Aside from this contractor barrier, manufacturers and distributors pointed to customer hesitation due to large up-front or long-term costs associated with CCHPs. In Michigan, CCHPs are less cost-effective than in other states due to the low cost of natural gas, but demand seems to be increasing, especially in rural areas where homes are predominantly heated with propane or oil.

This chapter provides contractor findings separately from manufacturer and distributor findings.

Contractor Findings

The Evaluation team interviewed eleven HVAC contractors to address three research objectives:

- Determine current awareness and perceptions of heat pump technologies.
- Identify the main barriers to installing heat pumps in Michigan.
- Identify marketing and outreach best practices.

The key findings corresponding to each research objective are outlined below.

Cold-Climate Heat Pump Awareness and Perceptions

Contractors' overall awareness of and attitudes toward CCHP technologies were largely correlated with the type of fuel available to the contractor's customer base. Contractors serving rural populations were more familiar with ducted systems, displayed an overall greater affinity for heat pump technologies, and reported higher levels of customer awareness and demand. Conversely, contractors serving urban populations were more familiar with ductless systems and displayed comparatively lower levels of familiarity with improvements in CCHP capabilities.

Contractors indicated that general awareness of heat pump technologies among customers was low but increasing. Contractors reported a marginal increase in the number of customers asking for the technology in recent months, and a more substantial increase in customers who were aware once the contractor presents CCHPs as an option. Similarly with contractor awareness, customer awareness is largely correlated with location and the availability of natural gas.

> "The typical customer is not aware it [CCHPs] is a heating option."
>
> - Contractor

Best Cold-Climate Heat Pump Applications

Contractors detailed the various scenarios in which CCHPs are currently being adopted by customers, or where they make the most sense for future adoption. For ducted systems, contractors reported the three best applications:

- Customers with propane or delivered fuels who have no access to natural gas
- Green-motivated customers who are not as cost conscious
- New construction

The best applications for ductless mini splits differ by heating versus cooling:

- Heating
  - Customers with electric baseboard heat—especially multifamily customers
  - Customers with hot or cold spots not served well by the existing system (and who could use heat pumps for supplementary heat)
- Cooling
  - Customers with no existing duct work (such as those with a boiler or electric baseboard heat)
  - Commercial applications, such as computer server rooms or elevator rooms
  - Vacation homes (that are not occupied in the winter)[12]

[12] Note that secondary or vacation homes were not eligible for the pilot.

Barriers to Adoption

Contractors provided a variety of reasons for the relatively slow adoption of heat pump technologies to date. Barriers primarily relate to financial constraints, either the up-front cost of the equipment or the comparatively higher operating cost (where natural gas is available). Adding to concerns over the operating cost is the idea that electric rates can be somewhat variable, so even if a contactor is able to project the operating cost of equipment for their customer, there is no guarantee that the projection will be accurate in the future. Furthermore, even when projecting operating costs using a fixed cost of electricity, there are no readily available tools by which contractors or customers can make accurate projections of the total system cost (equipment and operation). Several barriers were identified:

- Higher equipment cost versus other systems
- Relative higher cost of electricity compared to natural gas
- Variability in electric rates
- Inability to make accurate comparisons between the operating costs of CCHP systems to traditional heating systems
- Lack of education and awareness for the public and contractors alike
- Contractor perceptions of poor performance in the Michigan climate (less common)

Installation complexity and cost, supply chain robustness, and previous experiences with heat pumps are not seen as barriers among contractors. Contractors detailed how heat pumps generally require minimal additional work compared to traditional systems, and that relative to the additional cost of the equipment itself, the additional installation costs are negligible.

> "ASHPs [air-source heat pumps] have fallen off [become less common] for a couple reasons: most homes lately have a natural gas option, so we feel it is more to their advantage to use the gas furnace than air-to-air heat pumps."
>
> - Contractor

Overcoming Barriers to Adoption

There was no consensus among interviewed contractors as to what would be most influential in increasing CCHP adoption. Two contractors referenced a different rate structure for customers who use electric heat: Consumers Energy used to offer a special rate for customers with electric heat, and one contractor said the number of heat pumps they install has decreased since this rate was rescinded. These contractors believe that introducing an electric heating rate would potentially help to price CCHPs more similarly to natural gas–fired systems and lead to increased adoption:

- "If you choose a certain heating system, they used to offer a heating energy price decrease. If Consumers [Energy] could bring something like this back, demand would explode. Offer special rates for HP [heat pump] use for heating."
- "Used to do heat pumps more when they offered an electric heating rate, but we've switched to mostly natural gas due to cost of use."

Two contractors indicated that additional customer education is necessary to increase CCHP adoption, with one proposing a potential marketing campaign similar to the thermostat promotions that Consumers Energy currently offers. Other suggestions included offering increased rebates and a tool that helps customers more accurately project the lifetime operating costs of heat pumps against other space heating options:

- "Messaging would be a big bonus for all the contractors. It would help with promoting them [CCHPs]. Like the thermostat promotions that have produced a lot of positive feedback, [a campaign promoting heat pumps] would be very helpful."
- "Just educating people about that they've gotten the bugs out of these things [CCHPs] and they're working great."
- "Better rebates on them [CCHPs] for sure. With the [heat pumps] we have had a hard time meeting Consumers Energy's rebate requirements to qualify; our basic ASHP [air-source heat pump] doesn't qualify [and would] need to get up into the second or third level of efficiency, and with the increased cost the low [$100] rebates are not effective."
- "[It would be great] if Consumers [Energy] were able to come up with a tool comparing purchase and operational costs of electricity versus natural gas systems, showing savings of switching over when customers have dual fuel systems."

Marketing and Outreach Suggestions

As previously noted, two contractors said that increased customer education would be the most impactful way to increase customer demand for CCHP technologies. Each interviewed contractor suggested specific comparisons or promotional strategies to present the equipment to customers:

- Two suggested direct promotional campaigns from Mitsubishi that have been successful within Michigan
- One suggested using smart thermostat promotions from Consumers Energy
- One suggested promoting heat pumps as an air conditioner (AC) that also provides free heat
- One suggested offering a winter electric heating rate for owners with a CCHP
- One suggested providing tools to demonstrate savings compared to other systems

Income-Qualified Considerations

Two contractors indicated that unique circumstances may prevent the widespread adoption of heat pumps for income-qualified customers:

- The potential for theft of the costly units
- Low-income property managers' aversion to potential equipment issues and ensuing repairs

Distributor and Manufacturer Findings

The Evaluation team interviewed five distributors and two manufacturers of CCHPs in Michigan to address several research objectives:

- Confirm and document the supply chain for CCHPs in Michigan
- Identify the barriers leading to extended timelines for CCHP installation
- Identify sources of differences in CCHP installation costs across states
- Explore the cause of low participation by trade allies
- Identify any additional barriers and challenges delaying the widespread adoption of CCHPs in Michigan, like training or education
- Identify ways in which Consumers Energy can influence market adoption

The key findings corresponding to each research objective are outlined below.

Cold-Climate Heat Pump Supply Chain

Manufacturers and distributors confirmed that CCHPs follow a traditional supply chain structure, with no difference compared to traditional air-source heat pumps (ASHPs) or other types of HVAC equipment. While this typically means that units move from the manufacturer to the distributor and then to a contractor before reaching customers, there are exceptions for national corporate customers, who may purchase equipment directly from a distributor rather than through a contractor (see Figure 1).

Many CCHPs are manufactured abroad and shipped to ports in the United States, primarily to California or Georgia, before being trucked to regional destinations.

Figure 1. Heat Pump Supply Chain

Installation Timelines

Distributors reported it takes from one to 20 weeks to receive inventory from manufacturers, depending on whether the manufacturer is overseas or domestic and whether they placed a rush order. Manufacturers and distributors reported experiencing manufacturing delays as a result of COVID-19, as

well as ongoing transportation delays that included backups at ports and a truck driver shortage that began in 2018, prior to the pandemic.

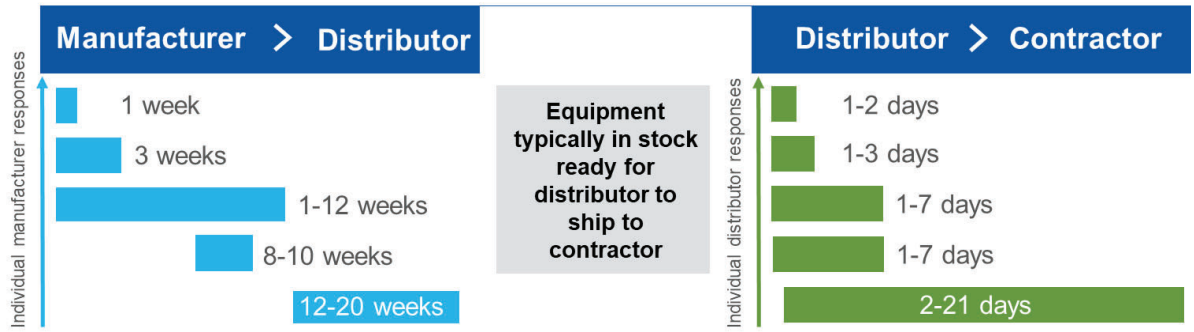
Despite manufacturing and transportation delays, distributors generally reported having stock on hand, so installation times were either not impacted or were only impacted temporarily. For the most part, distributors had learned how to manage around these constraints by being proactive and front-loading inventory. With enough inventory in stock, they can prevent delivery delays from impacting installation timelines:

- "With COVID-19, a lot of the supply chains have been broken. We were very responsive and proactive this year by buying up huge amounts of inventory. If we were to stop purchasing equipment now (March 2021), we would have enough equipment to last through November." – Distributor
- "This whole COVID thing really threw a wrench in a lot of this, and so I think a lot of it, the success that we have seen, having a little bit of inventory in Michigan, has to be to the credit of the distributor being proactive." – Manufacturer

When distributors have stock on hand, they reported that they typically deliver equipment to the contractor within one week, as shown in Figure 2. For a custom system or for equipment not in stock, the delivery timeline can stretch to three weeks or more, and one distributor had seen delays reach as long as six to eight weeks at points earlier in the pandemic, saying, "Much like everything else in the world, COVID really wreaked some havoc on manufacturing, so you know there were some times when it was six to eight weeks, but thankfully with good planning, we had enough stock that we really didn't have to deal too much with it [delays]." One distributor stated that custom equipment requires roughly 30 days to get to the contractor. Note that with the exception of this one distributor, timelines for custom equipment were not discussed in the interviews. It is possible that timelines for custom equipment could be different.

Notably, manufacturers and distributors have not observed any issues with the supply chain or with installation timelines that are unique to CCHPs or to Michigan.

Figure 2. Equipment Delivery Timelines Reported by Distributors



Note: The range in times for equipment to be delivered from the manufacturer to the distributor is due to differences between oversees versus land shipping and rush versus standard orders. One distributor also noted that COVID-19 led to six- to eight-week delays in equipment getting from the distributor to the contractor.

Cold-Climate Heat Pump Cost Differences across States

Most interviewed distributors and manufacturers did **not** report CCHP cost differences between Michigan and other states. One exception was a distributor who reported that installation costs in Michigan are higher compared to the Northeast. The distributor linked this difference to lower familiarity among installers in Michigan and said they expect costs to go down as installers become more familiar with the technology.

Within Michigan, interviewees observed differences in cost based on location in the state, with labor costs in urban areas being higher than costs in more rural areas. As one distributor stated, "Michigan prices are pretty average compared to Ohio [prices]. If you're in a more rural area, installation prices tend to go down, and if you're in a bigger, more metropolitan area then prices tend to go up."

One manufacturer also pointed out cost differences depending on whether contractors are union or non-union: "We go from $85 an hour that a contractor will charge a consumer to $140, especially if they are [in] a union. Or [when] you get into the Motor City, they seem to think they can charge a lot more."

Four of the five distributors reported increased CCHP costs over the last six months, and two interviewees noted that the cost of materials is rising—particularly for sheet metal, steel, and copper—which could lead to further cost increases down the road. As one distributor said, "[Internal costs] are going through the roof, [and] manufacturers can't eat it all."

Contractor Engagement

All five of the interviewed distributors shared the perception that there are still contractors in Michigan who do not have a full understanding of CCHPs and need to become more familiar with the technology and benefits. All five distributors also reported offering trainings to contractors to further their knowledge of CCHPs, including installation and service trainings as well as sales-oriented trainings: "We do training at every level possible, from technical service/installation to sales, and we have even offered business training."

Reports of attendance at trainings varied, with three who said their trainings were well-attended, one who said there was a mix of well-attended and less well-attended trainings, and another who said they were not well-attended, which they attributed to a lack of awareness of CCHP technology. One distributor also reported that, in their experience, one-on-one trainings work better than trainings offered in a group setting. Many training offerings have been moved to virtual platforms like Zoom due to the pandemic, which two distributors noted has been more challenging than in-person trainings.

Interviewees noted that trainings do not differ by state, e.g., they do not address specific climate, available programs, or current policies.

Barriers to Adoption

Four distributors mentioned that one barrier to CCHPs becoming more common in Michigan is that awareness of and trust in CCHP technology is not yet widespread among contractors in the state.

Instead, they reported that many contractors continue to hold an outdated perception that heat pumps are not a viable option in cold climates:

- "A lot of the contractors, especially a lot of the old timers... They don't see heat pumps as a viable option in Michigan. We hear that so many times." – Distributor
- "As technology continues to get better and heat pumps can operate at lower temperatures, you're always going to have an old service tech or installer that absolutely does not believe in the new technology." – Distributor
- "A lot of contractors are not as informed as they could be." – Distributor

Other barriers mentioned include concerns about up-front and long-term costs and, relatedly, the lack of incentives (since current policies in Michigan do not allow utilities to incentivize customers to switch from natural gas heat to electric heat).

Interviewees reported that demand for CCHPs is higher in other states than in Michigan. One attributed this lower demand in Michigan to the lack of widespread understanding among contractors and customers that heat pumps can be effective in cold climates. Others discussed the trade-offs in switching from different fuel sources. One distributor pointed out that natural gas is cheaper in Michigan than in other states, making CCHPs less cost-effective, and therefore less appealing, for those who currently use natural gas heating.[13] For those who use more expensive propane or fuel oil systems, however, distributors felt switching to a heat pump *would* be more cost-effective: "All-electric heat is a no-brainer. If they have propane or fuel oil, [heat pumps] make sense. With a natural gas system, it is a tougher sell."

Overcoming Barriers

Although interviewees reported that demand for heat pumps is lower in Michigan than elsewhere, they have also observed that demand in the state is increasing. Two distributors reported seeing major growth in CCHP adoption in recent years: one reported that their 2021 quarter 1 CCHP sales were greater than CCHP sales in the previous two years combined, and another reported having record demand in 2020, with sales doubling from 2019.

> "Ductless mini-splits are a huge, growing market, [with] the largest growth potential of any [technology], and everyone is saying the same thing."
>
> - Distributor

While there are still awareness and education gaps, interviewees reported that contractors and customers are becoming increasingly familiar as CCHPs have become more technically viable. As mentioned above, CCHPs are also increasingly *economically* viable in rural areas where there is a reliance on propane and oil heat.

[13] The proportion of households in Michigan with natural gas heating (82%) is higher than in most other states (Consumers Energy. 2018 Residential Saturation Study. Not available online).

The two biggest tools that interviewees noted as key to increasing CCHP adoption are incentives and increasing contractor and customer education. Several distributors emphasized that incentives and rebates are highly appealing to customers, making them an important tool for increasing adoption:

- "Customers would be willing to switch with an incentive." – Distributor
- "Incentives help to drive adoption." – Distributor

> "[It's] all about making the contractors aware of the benefits."
> – Distributor

Contractor education is also seen as a need, both to increase awareness of the viability of CCHPs in the state and to improve contractors' understanding of the benefits and cost-effectiveness of CCHPs.

Increasing Adoption

Distributers and manufacturers mentioned that Consumers Energy has been actively working to increase CCHP adoption, and they see the role of utilities as critical in helping this new technology gain a foothold.

> "The role of the utility is very important because they are the ones that can accelerate the [adoption of CCHP] technology."
> – Distributor

Distributers and manufacturers suggested that Consumers Energy can further encourage adoption in three ways: through education and training, by providing sales tools, and by offering incentives. Additional education and marketing directed at customers is needed to increase their awareness of the benefits of CCHPs.

> "There is a lack of information about the difference between costs for gas and electric."
> – Distributor

Similarly, interviewees suggested providing in-person trainings to contractors about rebates and the benefits of CCHP technology, including targeted trainings for technicians who may need more help to transition to a new technology. Three interviewees also said it would be useful to have a calculator tool that helps contractors easily demonstrate cost savings for switching to CCHP technology.

Interviewees also suggested that higher incentives would be instrumental in increasing CCHP adoption, and primarily felt that incentives should be offered via a midstream strategy. While one interviewee said rebates should be directed to contractors, all the other interviewees suggested that rebates should be directed to distributors, with one saying it would be helpful to have automatic incentives that minimize paperwork. One interviewee also suggested that incentives should be provided for CCHPs that have equivalent seasonal energy efficiency ratio (SEER) ratings as incentivized air conditioners.

> "Utility rebates really help. In some cases, the rebate has been able to cover the difference [between an AC and a heat pump]."
> – Distributor

Residential Market Rate Initiative Findings

In November 2021, the Evaluation team sent a survey invitation to 29 Residential Market Rate pilot participants who had valid emails. The email survey invitation included a $15 incentive for taking the survey. Nine of the 29 participants completed the survey, for a 31% response rate; with such a small sample size, the results should be interpreted with caution and only viewed as directional indications (not intended to be analyzed with statistical confidence).

In addition to the participant survey, the Evaluation team conducted an engineering analysis to determine market rate CCHP participants' energy and utility bill cost savings. The Evaluation team used data collected from the Consumers Energy initiative team and calculations that can be found in the *Michigan Energy Measures Database* (MEMD).[14]

This chapter first provides details of Residential Market Rate pilot participants, then covers the engineering analysis findings.

Market Rate Participant Survey

The Evaluation team designed the participant survey to address several key objectives:

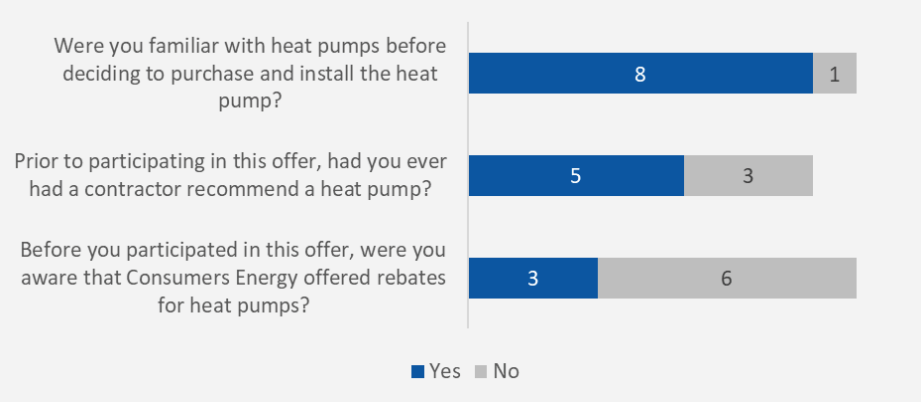
- Assess awareness of and motivation for installing heat pumps
- Assess the participant installation experience
- Document perceptions of heat pumps, energy or cost savings, and comfort levels
- Document participant usage behavior
- Assess satisfaction with the offering and with Consumers Energy

Awareness and Motivation

All nine respondents confirmed that they received a rebate for their heat pump and that they were present when the heat pump was installed. While most (eight of nine) were familiar with heat pumps before deciding to purchase one for their home, few (three of nine) were aware that Consumers Energy provided heat pump rebates (Figure 3). Respondents first learned about Consumers Energy's heat pump rebate primarily through their contractor (four of nine) or from a Consumers Energy email (two of nine). About half (five of nine) said a contractor had recommended a heat pump before they learned about and applied for the Consumers Energy heat pump rebate.

[14] Michigan Public Service Commission. *Michigan Energy Measures Database.* https://michigan.gov/mpsc/regulatory/ewr/michigan-energy-measures-database

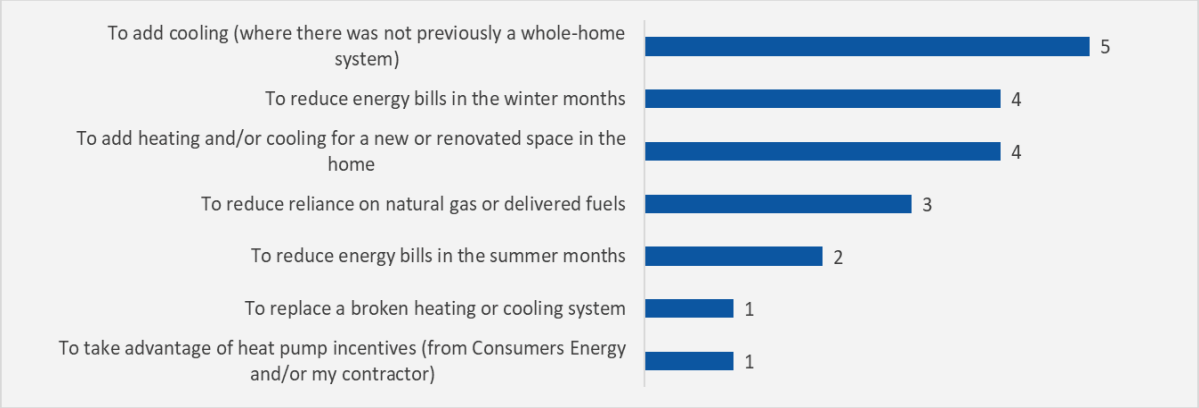
Figure 3. Heat Pump Awareness



Source: Heat Pump Market Rate Customer Survey Questions B3, B4, and B5 (n=9).

Although respondents could indicate several different motivations for installing a heat pump, responses were most frequently associated with space cooling needs and saving money on energy bills. Most respondents (n=5) installed a heat pump to add cooling where there was not previously a whole-home space cooling system. Four respondents each wanted to reduce energy bills in winter months and wanted to add space heating or cooling for a new or renovated space. Three respondents wanted to reduce their reliance on natural gas or delivered fuels (Figure 4).

Figure 4. Motivations for Installing a Heat Pump



Source: Heat Pump Market Rate Customer Survey Question B7. "What were the main reason(s) you decided to install a heat pump in your home?" (n=9; multiple responses accepted)

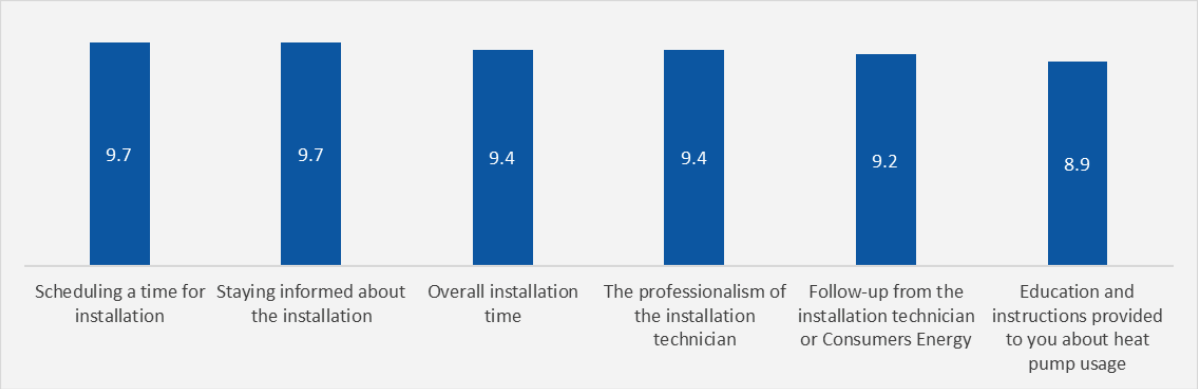
When asked to rate the importance of several factors in their decision to install a heat pump, respondents rated energy savings (over the previous heating/cooling system) as the most important (with a mean rating of 9.1 on a 10-point scale, where 1 meant *not at all important* and 10 meant *extremely important*). The contractor's recommendation received a mean rating of 8.0, and the rebate amount received the lowest rating of all decision factors, at 7.6.

Installation Experience

Respondents were engaged with the installation experience: all of them were present during the installation. Most (eight of nine) received instructions on how to set up and control the heating and cooling schedule on their heat pump at the time of installation. Only one respondent said the installation contractor set up a heating and cooling schedule for them but said they had adjusted that original schedule to address changes in their home's conditioning needs.

Respondents provided very high ratings for aspects of the installation experience, with scheduling and staying informed about the installation receiving the highest mean ratings (of 9.7 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding*; see Figure 5).

Figure 5. Installation Experience Ratings



Source: Heat Pump Market Rate Customer Survey Question D2. "How would you rate each of the following installation experiences with the heat pump offering?" (n=9)

The lowest rating (of 5) was provided by one respondent for the "education and instructions provided about heat pump usage," but that person did not answer the follow-up question about why they gave that rating.

Heat Pump Perceptions

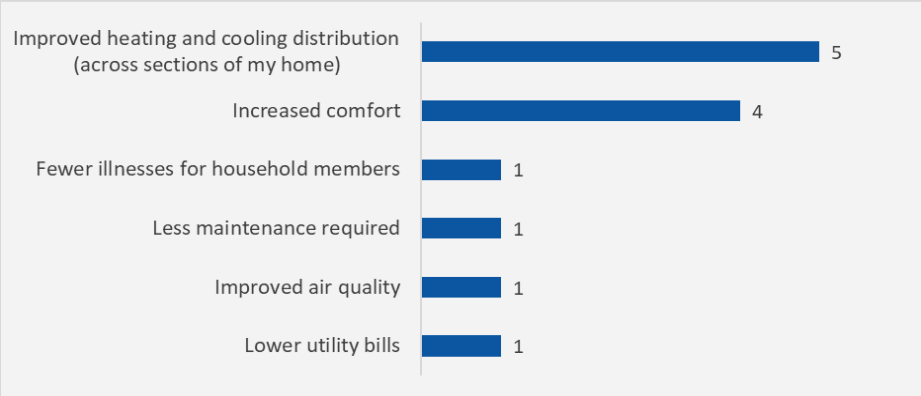
Most respondents (seven of nine) said their home is more comfortable after installing the heat pump, while the other two respondents said their home is equally as comfortable as before the heat pump was installed. One respondent also volunteered that their home air quality was vastly improved, which was also a primary reason they installed the heat pump.

Five respondents rated the comfort level provided by the heat pump in winter months, providing a mean rating of 8.6 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding*. None indicated any concerns with the heat pump's ability to heat to a preferred comfort level. Comfort ratings for summer months were higher, at an average of 9.1 with ratings from all nine respondents.

Overall, perceptions were mixed about whether respondents had seen savings on their energy bill since the heat pump was installed. Four respondents said it was too soon to tell if their energy bill was affected, while two said they had a lower-than-expected energy bill and two said they had not seen a lower-than-expected energy bill.

In addition to energy savings, respondents reported several additional benefits that they value in their heat pump. With several response options provided, the most frequent benefit selected (by five respondents) was improved heating and cooling distribution across sections of the home (Figure 6). This was followed by four respondents who said the heat pump provided increased comfort. One respondent each indicated having lower utility bills, less required maintenance, improved air quality, and fewer illnesses for household members.

Figure 6. Heat Pump Benefits

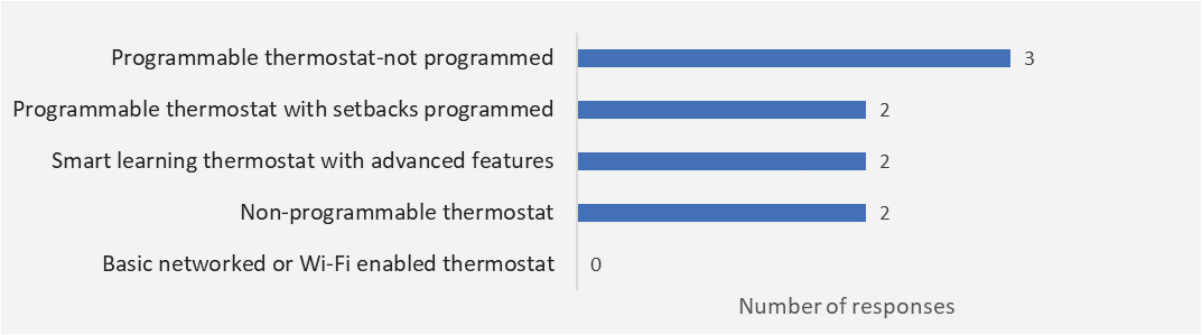


Source: Heat Pump Market Rate Customer Survey Question D13. "In addition to energy savings, if any, are there any other benefits you have experienced or observed from the installation of a heat pump?" (n=9; multiple responses accepted)

Thermostat Usage Behavior and Experience

While five of nine respondents had programmable thermostats, only two of those five used programmed temperature setbacks to control their heat pump temperature settings. Two respondents had smart learning thermostats with occupancy sensing and schedule learning capabilities, and two others had non-programmable thermostats with manual-only controls (Figure 7).

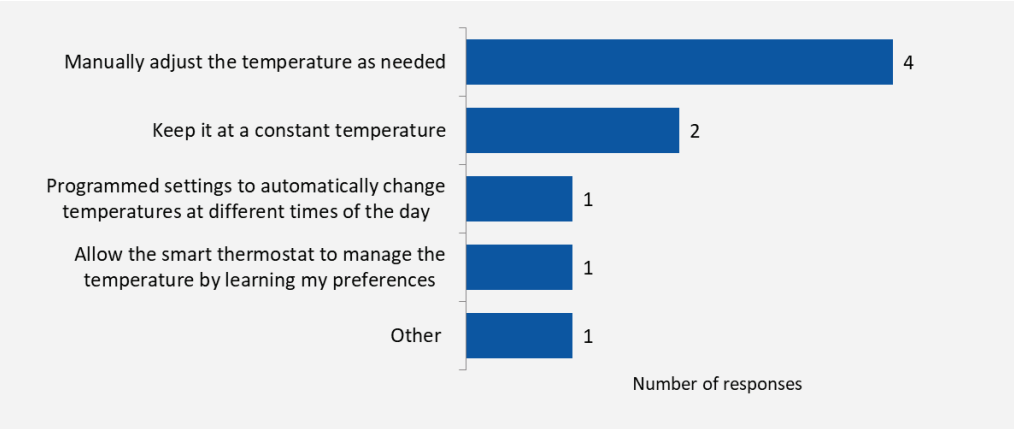
Figure 7. Respondent Thermostat Types



Source: Heat Pump Market Rate Customer Survey Question C1. "What type of thermostat do you have in your home?" (n=9)

Respondents, either singularly or with other household members, monitor and adjust the home heating and cooling settings. Despite most having programming capability through their thermostats, four of nine said they adjust the temperature manually (Figure 8).

Figure 8. Thermostat Management



Source: Heat Pump Market Rate Customer Survey Question C3. "How did your household most frequently manage your thermostat to control the temperature in your home this summer?" (n=9)

Satisfaction with the Offering and with Consumers Energy

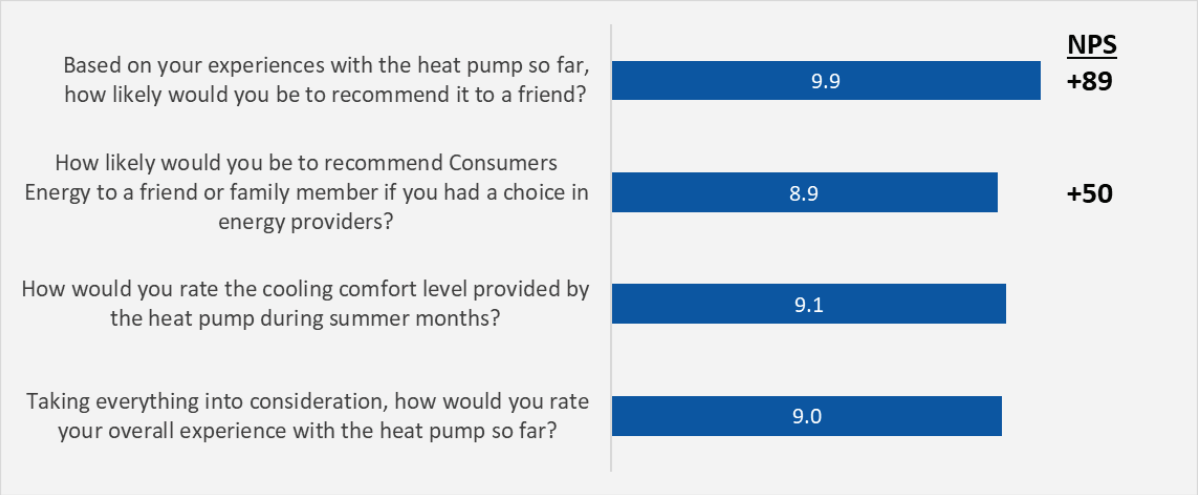
Overall, respondents were highly satisfied with the heat pump (giving a mean rating of 9.0 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding*), with all nine respondents giving a rating of 8 or higher for their overall experience with the heat pump.

Another key measure of customer satisfaction is the percentage of customers who are highly willing to recommend a product, service, or company after subtracting the percentage of customers who are highly unlikely to recommend that same product, service, or company. The net percentage of those willing to promote the product is the net promoter score (NPS), expressed as an absolute number between -100 and +100 that represents the difference between the percentage of promoters (respondents giving a rating of 9 or 10) and the percentage of detractors (respondents giving a rating of 1 to 6). The Evaluation team calculated a NPS for the two likelihood to recommend questions (likelihood to recommend the initiative and likelihood to recommend Consumers Energy).

Based on their experiences, respondents were highly likely to recommend the heat pump to a friend. As shown in Figure 9, nearly all respondents (eight of nine) gave a rating of 9 or higher (with a mean of 9.9), with three indicating that they had already recommended the heat pump rebate to a friend. The resulting NPS for the heat pump is +89.

Five of eight respondents (63%) provided a rating of 9 or 10 for their likelihood to recommend Consumers Energy to a friend. Only one respondent rated their likelihood to recommend as a 5. The resulting NPS for Consumers Energy is +50, with a mean rating of 8.9.

Figure 9. Market Rate Heat Pump Participant Satisfaction



Source: Heat Pump Market Rate Customer Survey Questions D10, B1, D7, and D9. All questions used a 10-point rating scale, where 1 meant *extremely unlikely* and 10 meant *extremely likely*, with an "already did" response option as a 10 rating (n=9).

The NPS for recommending the heat pump is considered very high and compares favorably to other efficiency programs with similar measures. For example, HVAC participants provided a program NPS of +76 and a Consumers Energy NPS of +63 in 2021. Again, caution is recommended in interpreting numeric results due to the small sample size with the Residential Market Rate pilot response population.

When asked to elaborate on their rating for recommending Consumers Energy, respondents gave positive comments:

- "Consumers Energy has been a good power company. They keep us informed on rebates, power outages, etc. During power outages they are great at restoring power quickly and keeping us informed on time frames. The rebate for heat pumps was one of the reasons we decided to try a heat pump. Our power bill has gone up, but we are using our heat pump a fair amount. It is still a better option than the window air conditioner that we had before."
- "It's been a great company. I grew up in a Consumers [Energy] home and have had one [a heat pump] my entire adult life."
- "High marks for programs and communication."
- "Very happy with service and energy offers."
- "[I] like that Consumers [Energy] is trying to help on heating costs that are going up every year."
- "We don't really have much choice, but I think that Consumers Energy does a good job providing (mostly) reliable electric service (which is all you [they] provide to my area)."

Two respondents said they do not have a choice in energy company, so they do not have a point of comparison, and one commented on high rates.

The only improvement suggestion respondents provided did not directly pertain to the heat pump initiative: "Allow me to change the energy conservation program I want more than once a year. We would like to 'follow the rules' imposed during the summer year-round but cannot change because we cancelled the program we had been on (Consumers [Energy] could limit our AC during peak periods) because our contractor did not want Consumers [Energy] to be able to change our now Wi-Fi–capable system (the old one was not [Wi-Fi]) in May/early June. We did not find out about the option we'd like until later in the summer but were not allowed to use it."

Impact Analysis

The Evaluation team conducted an engineering analysis of the impacts from the Residential Market Rate pilot and relied on MEMD assumptions and information we had collected from customers such as home vintage, presence of central cooling, installed system coefficient of performance (COP)[15] at 5°F, rated heating seasonal performance factor (HSPF) and SEER, tonnage, and other data. The Evaluation team relied on the MEMD weighting tool, which generates a single measure output based on home vintage, climate zone, sizing, and efficiency levels. Since the MEMD weighting tool does not allow for varying the baseline equipment type or system efficiency, the Evaluation team used MEMD building simulation output data to develop site-specific consumption values. MEMD staff provided underlying MEMD 2019 weighting tool building simulation results for ASHPs in single-family buildings.[16] This section summarizes key findings from the engineering analysis.

There were 42 Residential Market Rate pilot CCHPs installed in homes with electric and propane heating, making up the largest percentage of pre-installation heating fuels (Table 6). Approximately half of the CCHPs were installed in homes built before 1979 (n=25) and most of the other half were installed in homes built between 1980 and 2004 (n=23). The remaining CCHPs were installed in homes built between 2005 and present day (n=3).

Table 6. Home Construction Vintage Distribution by Pre-Installation Heating Fuels

Pre-Installation Heating Fuel	1979 or older	1980 to 2004	2005 to Present	Total
Electricity	10	6	0	**16**
Propane	9	15	2	**26**
Fuel Oil	3	1	0	**4**
Natural Gas	3	1	1	**5**
Totals	**25**	**23**	**3**	**51**

[15] Coefficient of performance is simply the ratio of power (kW) in heating (or cooling) Btus generated by the CCHP, and the power (kW) that is supplied to the compressor. The higher the COP, the greater the heating energy generated for each kilowatt consumed by the CCHP.

[16] The MEMD 2021 building simulations for this measure have not been updated since 2019 and therefore reflect the latest building simulation results.

Table 7 shows the average Residential Market Rate pilot participant' annual energy and utility bill savings by pre-installation heating fuel type. Customers heating with delivered fuels (propane and oil) realized the highest heating energy savings, while customers heating with electricity prior to installation of the CCHP had the highest utility bill savings.

Table 7. Average Market Rate Cold-Climate Heat Pump Energy and Fuel Cost Savings per CCHP

Pre-Installation Heating Fuel	Number of Installed Units	Average Savings per CCHP		Average Annual Utility Bill Savings per CCHP
		Heating (MMBtu) [a]	Cooling (kWh) [b]	
Electricity	16	35	-108	$1,680
Propane	26	68	-27	$1,223
Fuel Oil	4	70	-46	$910
Natural Gas	5	54	-228	-$451

[a] Due to the different heating fuel types, savings are represented in MMBtu to allow for better comparisons.

[b] Negative savings mean that electric consumption increased rather than decreased.

The five homes that heated with natural gas will likely see an increase in their utility bill of $451 per year on average due to the relative costs of electricity and natural gas at the time of the analysis, as well as the fact that four of five homes did not have existing central AC (which will likely increase their electric usage in the summer).

As shown below in Table 8, only 22 of the 51 participants had central AC prior to the CCHP installation. For homes without central cooling, the Evaluation team assumed a portion of the homes use room or window AC units to provide some cooling. Due to the low number of homes without conditioned cooling, electric consumption increased, on average, across all baseline heating fuel types. However, homes that did have central cooling before the CCHP installation saw savings from $20 to $96.

Table 8. Central Cooling Presence Distribution and Associated Cooling Savings

Pre-Installation Heating Fuel	Central Cooling?	Number of Installed CCHPs	Annual Cooling Electric Savings per CCHP
Electricity	Yes	5	$33
	No	11	-$37
Propane	Yes	15	$57
	No	11	-$69
Fuel Oil	Yes	1	$96
	No	3	-$35
Natural Gas	Yes	1	$20
	No	4	-$50

Table 9 shows the total Residential Market Rate pilot annual energy and utility bill savings by pre-installation heating fuel type for all CCHPs.

CADMUS

Table 9. Total Market Rate Heat Pump Energy and Fuel Cost Savings

Pre-Installation Heating Fuel	Count of Installed CCHP Units	Savings		Annual Fuel Costs [b]		Pre-Installation Central Cooling Saturation [c]
		Heating (MMBtu) [a]	Cooling (kWh)	Heating	Cooling	
Electricity	16	565	-1,729	$27,124	-$247	31%
Propane	26	1,774	-704	$31,701	$85	58%
Fuel Oil	4	279	-183	$3,652	-$10	25%
Natural Gas	5	270	-1,142	-$2,072	-$182	20%

[a] Due to the different heating fuel types, savings are represented in MMBtu to allow for better comparisons.

[b] The Evaluation team calculated annual heating and cooling costs based on rates and distributed fuel cost shown in *Appendix B*.

[c] Not every home was equipped with central cooling before the CCHP installation.

Income Qualified Multifamily Initiative Findings

There are two key groups of participants in the Income Qualified Multifamily initiative: property owners and managers (PMO) and tenants. PMOs are active participants who sign up for the initiative and are the primary contacts of the initiative. The tenants are indirect participants; they are not decision-makers, yet they directly benefit from the CCHP Initiatives' equipment and energy savings in their living units and they most frequently pay the resulting energy bills from CCHP operation. The Evaluation team sought feedback from both groups, conducting telephone interviews with PMOs and online surveys with tenants. The Evaluation team also sought to understand the Income Qualified Multifamily initiative's performance by analyzing electric energy savings impacts during the heating and cooling seasons through a statistical billing analysis of participating initiative properties.

This chapter outlines the results of PMO interviews, tenant surveys, and the statistical billing analysis.

Property Manager and Owner Interviews

The Evaluation team conducted telephone interviews with multifamily PMOs who participated in the CCHP initiative to gain insight into their experience. The Evaluation team designed the interview to address several key objectives:

- Document the participant installation experience
- Document participant usage behavior and experience
- Document awareness and perceptions of heat pumps
- Document participant decision-making around participating in the heat pump offering
- Identify marketing and outreach best practices
- Assess satisfaction with the offering and with Consumers Energy

As of Q3 2021, seven multifamily properties had participated in the Income Qualified Multifamily initiative. While the Evaluation team attempted to recruit all seven of the multifamily PMO initiative participants, we completed three phone-based in-depth interviews. Two of the multifamily PMO participants were from existing buildings (retrofit installations) and therefore had broad insights into the full initiative experience. The third interviewee was with a newly constructed property, which meant they had a more limited view on the tenant and installation experience.

Installation Experience

Overall, the multifamily PMOs had a positive early-stage initiative experience with scheduling, installation, and follow-up. Two of the three PMOs reported that COVID-19 caused some delays with the installation and equipment, but overall reported positive experiences. In one case, the PMO commented that the completion time was fast considering the number of units and installs: "We had something like 48 units, some large enough for multiple installations…so two-and-a-half months to install over 50 units was fast." The third PMO, the owner of a new construction property, noted the while installations were all completed on time, they did not have feedback on the tenant experience during installation (as installation happened before tenants occupied the units). For the other two PMOs with tenants living in

the units, the installer worked directly with management to notify the tenants of the installations and work around their schedules. According to these two PMOs, their tenants were generally satisfied with the heat pump installation.

Heat Pump Usage Behavior and Experience

The multifamily PMOs reported that prior to installation, tenants relied on inefficient electric baseboard systems and, in one case, had specifically requested new a HVAC system during a tenant meeting. One of the primary benefits for tenants is the ability to use AC as well as heating—while the heat pump replaced baseboard heat, there was no existing AC to replace outside of window units purchased by tenants. One PMO mentioned that nearly all tenants enjoyed the new heat pumps, with only a few tenants being confused about how to use the new system.

Two of the multifamily PMOs received direct feedback from their tenants regarding the heat pump usage and experience. According to one PMO, “the residents considered it a huge plus for them, because of all the extra benefits that the heat pumps provided them.” Another PMO remarked that the heat pumps provided significantly greater comfort, and improved air circulation, compared to the baseboard equipment, and went on to state, “the heating itself is just more efficient for the tenants; it seems to keep the apartments warmer.”

Awareness and Perceptions of Heat Pumps

Multifamily PMOs were generally aware of heat pumps prior to being approached by Consumers Energy about the rebate initiative, though they were not aware of Consumers Energy incentives or programs until their involvement in the initiative. One PMO previously had contractors recommend heat pumps, while another had heat pumps installed in other apartments in the Southeast United States (where heat pumps are more common). One of the PMOs had some hesitation about installing the CCHPs, as they noted, “historically, my understanding was that [heat pumps] didn’t do so well in cold climates. A green consultant and several HVAC engineers turned me on to them and then [I] became comfortable [that] they would be sufficient.”

PMOs generally did not report any perceived benefits of heat pumps prior to installation but were happy to report both energy and non-energy benefits, particularly tenant happiness and reduced maintenance and tenant comfort needs, after installation. As an added benefit, the simplicity of a single heating and cooling system was beneficial for both tenants and the PMOs: the number one benefit is providing heat, but efficient heat is the next important thing. As one PMO said, “There is always some kind of system [to heat], but it doesn’t always work. It’s always our number one concern to provide heating and cooling to the tenants.”

Decision-Making around Participating in the Heat Pump Offering

In both existing retrofit cases, the PMOs primarily decided to improve the existing HVAC systems due to energy efficiency and tenant comfort. One PMO cited a tenant meeting as a primary factor, where tenants explicitly requested an improved HVAC system. Generally, all PMOs wanted to improve tenant comfort, replace old equipment, improve electric efficiency, and lower electricity bills. The biggest barrier to switching over to heat pumps was cost: because the multifamily buildings already had existing

heating systems, it was a matter of prioritizing which are the most in need and how to fit that into the budget: "… if there is an existing heating system that is working, that's not necessarily something we can improve because it meets [the need for] having a functioning system, and it's harder and more expensive to switch out than other properties… so the biggest barrier is a matter of prioritizing it [CCHP installation] in the budget." According to the other retrofit PMO, the rebate allowed them to fit improved HVAC systems into the budget for that year. Tenant comfort, energy efficiency, and an improved system were the key motivations for PMOs.

For the new construction PMO, heat pumps were an attractive investment for their property, and the initiative made it "a slam dunk" for the project. The initiative allowed the property to meet LEED certification while also managing to keep the construction within budget. As the new construction PMO noted, "for our LEED-certified property, which was an all-electric building, and given [that] the units were smaller apartments, it was hard to find a furnace that would work well and integrate into the units and not be oversized. The heat pumps can really work well and are adapted to lower need, relative to [a] gas furnace. The simplicity of only electric, with no gas, requiring less piping, meant that construction was easier." This PMO went on to remark, "with the rebate, the heat pump was actually the cheaper option [relative to a gas furnace]."

Marketing and Outreach Best Practices

Multifamily PMOs agreed that the best way to conduct outreach about CCHPs is to directly contact contractors or developers. According to two PMOs, they primarily get their recommendations from contractors, who do not always provide information on CCHPs and higher-efficiency opportunities to the developers. One existing building PMO said, "if I had someone directly to talk to, I would bring this up to [building owners] more…I confer with architects and specialists on building recommendations, but they don't necessarily know all the tenant benefits. So, I would recommend reaching out to more developers, like myself, directly." Both PMOs recommended emails or pamphlets with the overall costs and energy savings and direct information as a convincing outreach strategy: "Anything that involves a description, some costs, energy savings…I think those are the highlights," the construction manager said.

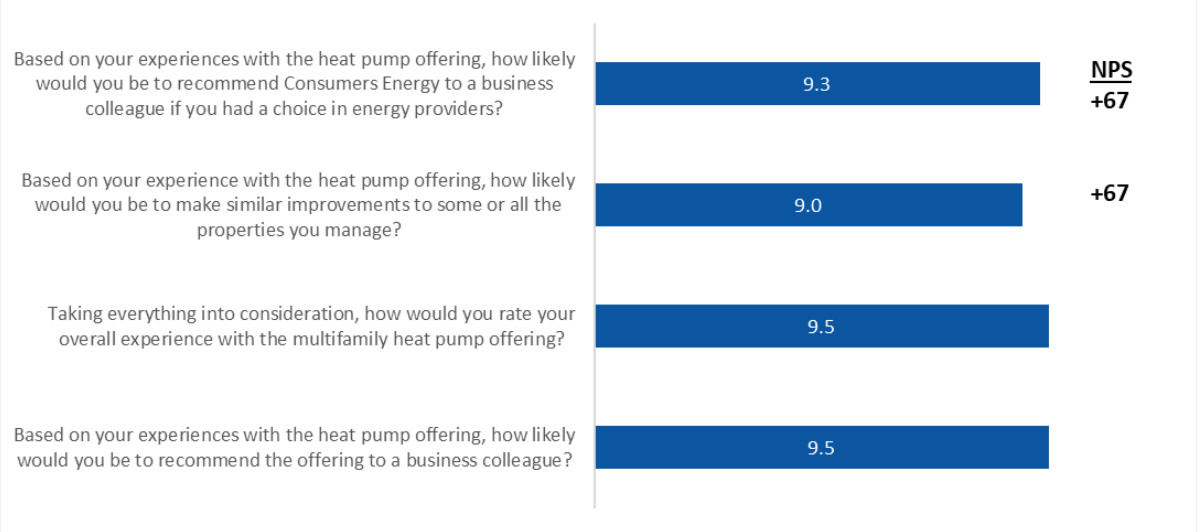
Two of the PMOs learned about the heat pump offering through direct contact with Consumers Energy, while one learned about it from their LEED consultant. When asked what the preferred means of communicating future offerings, all three PMOs tended to prefer email, but also noted phone calls.

One interviewee (the resident manager) mentioned that his property manager was the decision-maker in the process, and that energy companies should do more to contact property managers directly, because most are not aware. "[The property manager] was different," the resident manager said, "He was always searching for rebates and things like that…both to improve the apartments for the tenants, but also because of the resource—using less energy is good for the economy, that kind of thing. But most property managers aren't searching like he was." Another PMO said, "Most people don't know enough and aren't aware [that heat pumps] can work on their own in colder climates. We have now had a full winter with new tenants and the CCHPs and received no complaints: it all went well."

Satisfaction with the Offering and with Consumers Energy

Overall, the participating PMOs were highly satisfied with their initiative experience and with Consumers Energy (Figure 10). The three PMOs provided an average rating of 9.5 on a 10-point scale (where 1 meant *unacceptable* or *extremely unlikely* and 10 meant *outstanding* or *extremely likely*) for their satisfaction with the initiative and their likelihood to recommend heat pumps to a colleague. The PMOs also rated their likelihood to recommend Consumers Energy as a 9.3 and rated their likelihood to adopt similar CCHP equipment in their other properties as a 9.0 (Figure 10).

Figure 10. Multifamily Property Manager Owner Cold-Climate Heat Pump Satisfaction



Source: Heat Pump Property Owner and Manager Interview Guide Questions G1–G4.

Income Qualified Multifamily Tenant Survey

In November 2021, the Evaluation team surveyed a group of multifamily tenants who resided in units that received CCHPs as part of Consumers Energy's CCHP initiatives and 32 completed the survey

The Evaluation team designed the survey to address several key objectives:

- Document awareness of heat pumps
- Understand the participant installation experience
- Assess tenant perceptions of heat pump impacts on comfort levels and electricity bills
- Document participant usage behavior and experience
- Assess satisfaction with the offering and with Consumers Energy

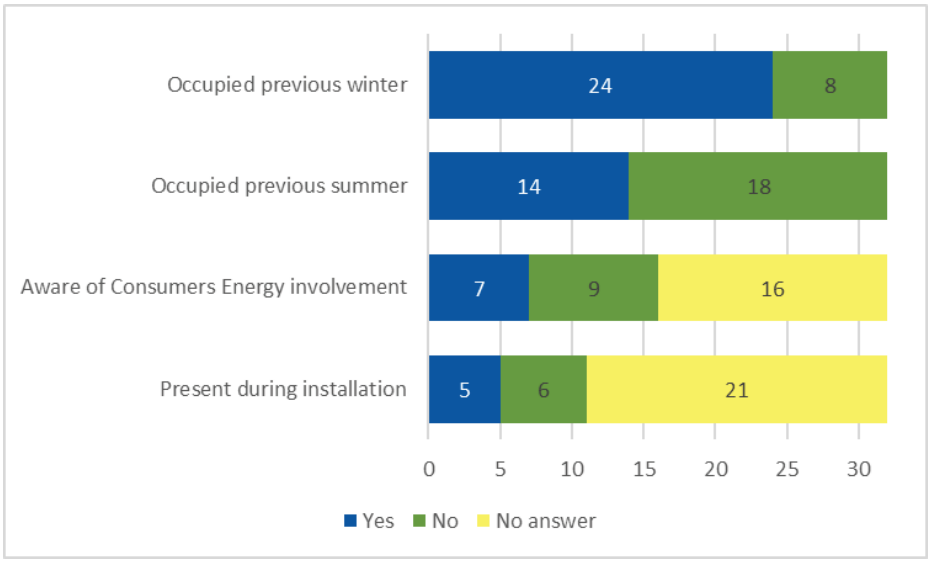
Tenant Survey Background

The multifamily tenant survey included questions about topics such as whether respondents manage the temperature of their unit, whether they pay their bills, and how long they have resided in their unit. Additionally, the team asked questions about the installation and performance of the CCHP.

All tenants who responded to the CCHP survey managed the temperature of their home personally and all said they pay their own energy bills (n=32). Most tenants (n=17) had lived in the apartment for between six months and one year while 11 others had occupied their apartment for more than one year. Additionally, three respondents said the heat pumps had not yet been completely installed and they could not provide answers about installation or post-installation.

Other participant characteristics are summarized in Figure 11. A minority of respondents were present during installation (n=5) and were aware of Consumers Energy involvement in the CCHP (n=7). Three-quarters of respondents were occupants last winter (n=24), before the installation, while one-quarter (n=8) were not present in their units to experience the old heating system, and thus could not provide comparative responses about new versus old heating system performance. Respondents' tenancy term and other factors resulted in around one-third (30%) of the responses to all questions that provided little to no insight into their experience in this initiative. Because of the low response count to many of the tenant survey questions, the results should be considered indicative but inconclusive.

Figure 11. Summary Respondent Characteristics



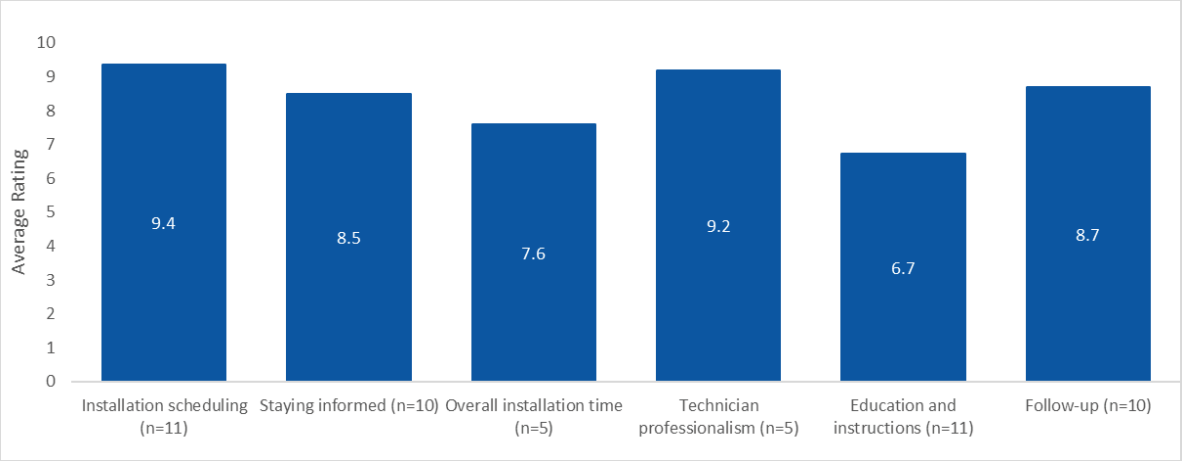
Source: Heat Pump Multifamily Tenant Survey Guide Questions C5, C8, B3, and C1. Please see *Appendix E* for specific question wording.

Participant Installation Experience

A successful equipment installation can provide tenants with a positive initiative experience; such an installation should include providing helpful information and operational details for a better managed heating and cooling experience. One-third of respondents (n=11) provided installation experience ratings. Overall, participants were largely satisfied with the installation experience, rating most installation elements above an 8 on a 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding* (Figure 12). Respondents provided the lowest average rating to the education and instructional aspects of installation, which impacted their overall satisfaction with the heat pump

offering, as well as with Consumers Energy overall (these metrics are featured further below in Figure 19).

Figure 12. Tenant Installation Satisfaction

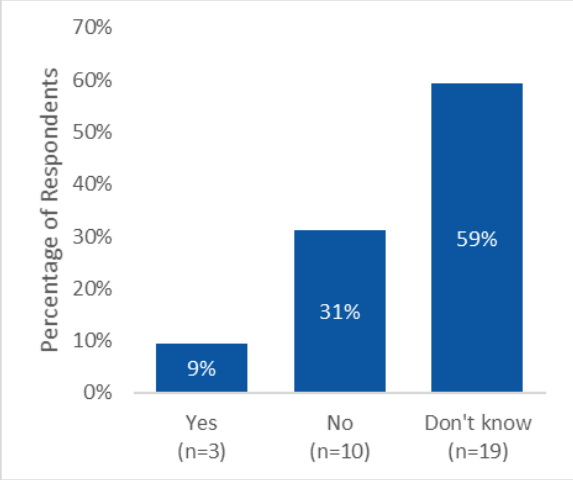


Source: Heat Pump Multifamily Tenant Survey Guide Question C2. "How would you rate each of the following installation experiences with the heat pump offering?"

Participant Usage, Behavior, and Experience

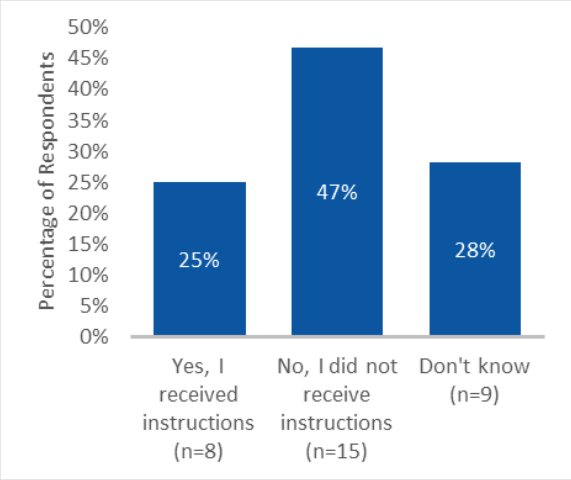
Participant usage, behavior, and experience with this offering were influenced by the installation technicians and education surrounding the CCHP equipment installation. Only three respondents could confirm with certainty that the technician set up a heating and cooling schedule for their heat pump (Figure 13). These three participants also confirmed that the heating and cooling schedule set up by the contractor is still in operation. Lack of heat pump education, materials, and follow up were common among respondents. Forty-seven percent of participants (n=15) reported not receiving documentation or instructions about the heat pumps, while 28% (n=9) did not know if they received instructions and 25% (n=8) did receive instructions (Figure 14). Other survey respondents indicated in open-ended responses that there was a lack of information relayed about the heat pumps, either from installation technicians, the PMOs, Consumers Energy, or a combination of the three.

Figure 13. Heating and Cooling Schedules



Source: Heat Pump Multifamily Tenant Survey Guide Question C16. "Did the installation technician set up your heat pump on a heating and cooling schedule?"

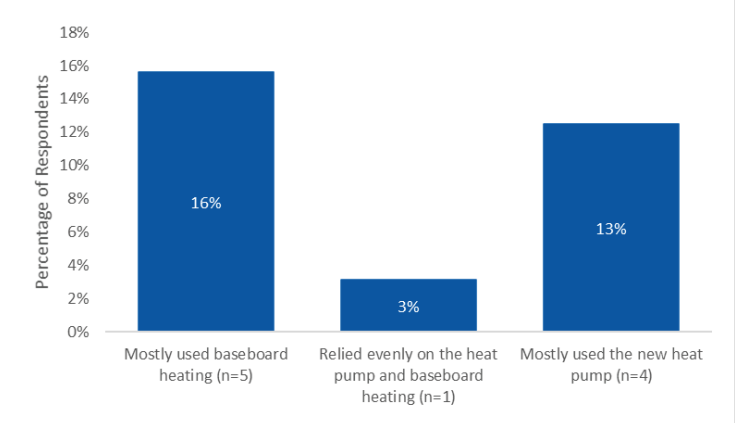
Figure 14. Instructions Provided at Installation



Source: Heat Pump Multifamily Tenant Survey Guide Question C18. "Have you been provided with instructions on how to set up and control your heating and cooling schedule on your heat pump?"

Sixteen percent (n=5) of participants reported using mostly baseboard heating after installation, while 13% (n=4) reported using mostly the newly installed heat pump and 3% (n=1) reported using both evenly. Another 68% (n=22) of participants did not know which heating source they relied on.

Figure 15. Primary Multifamily Tenant Apartment Heating Source



Source: Heat Pump Multifamily Tenant Survey Guide Question C12. "Which of the following best describes how you heated your apartment last winter?"

In open-ended responses, some tenants were unhappy with the lack of information:

- "After the installation, there was not follow up. Also, there are many in our complex that have no idea on how to set up the mobile app."
- "Manager of my complex did not [educate] me on how to use all the features. Also, when and who changes the filters, if any."

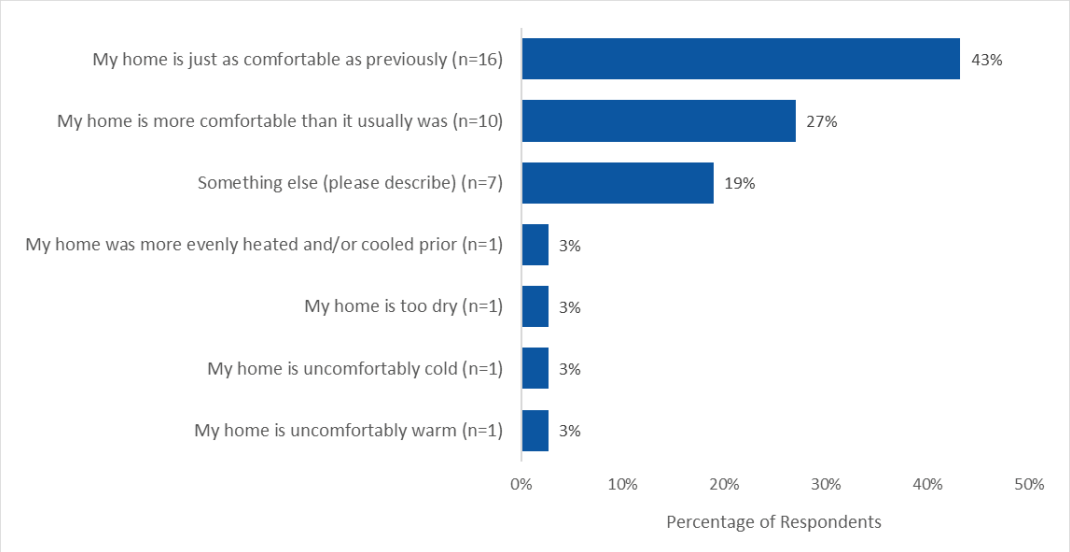
Awareness and Perceptions of Heat Pumps

Most participants (68%; n=21) reported a complete lack of knowledge regarding heat pumps, even after installation. More interestingly, half were not aware that there was a heat pump installed in their apartment, despite having occupied the unit at the time of installation. Of the half that were aware of the heat pump installation, 56% (n=9) did not know Consumers Energy was involved in the project. In an open-ended response, one participant was surprised: "I didn't know anything about how to run the heat pump or maintenance needed. We weren't told anything. We didn't even know Consumers [Energy] funded it."

Perceptions of Heat Pump Impact on Comfort Levels and Electricity Bills

As noted above, PMOs indicated tenant comfort was a key factor in the decision to participate in the heat pump initiative—some tenants supported this perception. Post-installation, although 43% of tenants reported their homes to be as comfortable as before, one-quarter of tenant survey respondents reported increased comfort (27%). Specifically, few tenants reported issues with temperature or humidity regulation, as shown in Figure 16.

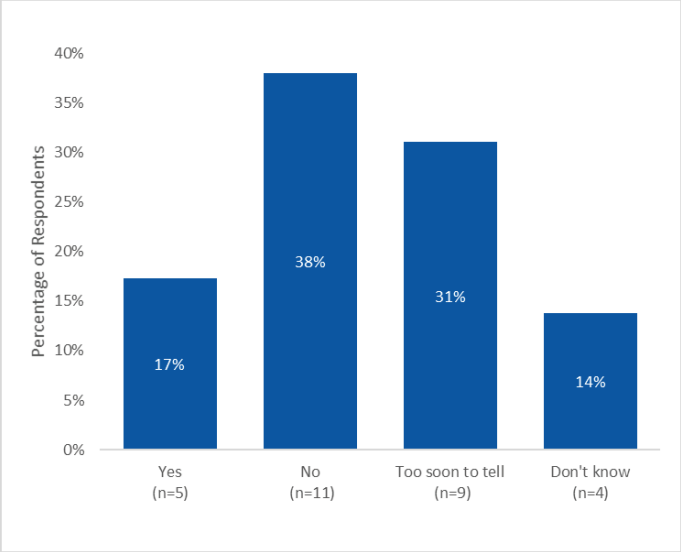
Figure 16. Heat Pumps and Home Comfort



Source: Heat Pump Multifamily Tenant Survey Guide Question C11. "In general, how did the heat pump affect your home comfort?"

Over twice as many income-qualified multifmaily respondents believed they did not experience any savings on their energy bills as those who believed they did experience savings: 38% of respondents (n=11) reported no savings on their energy bills, compared to 17% (n=5) who reported savings (Figure 17).

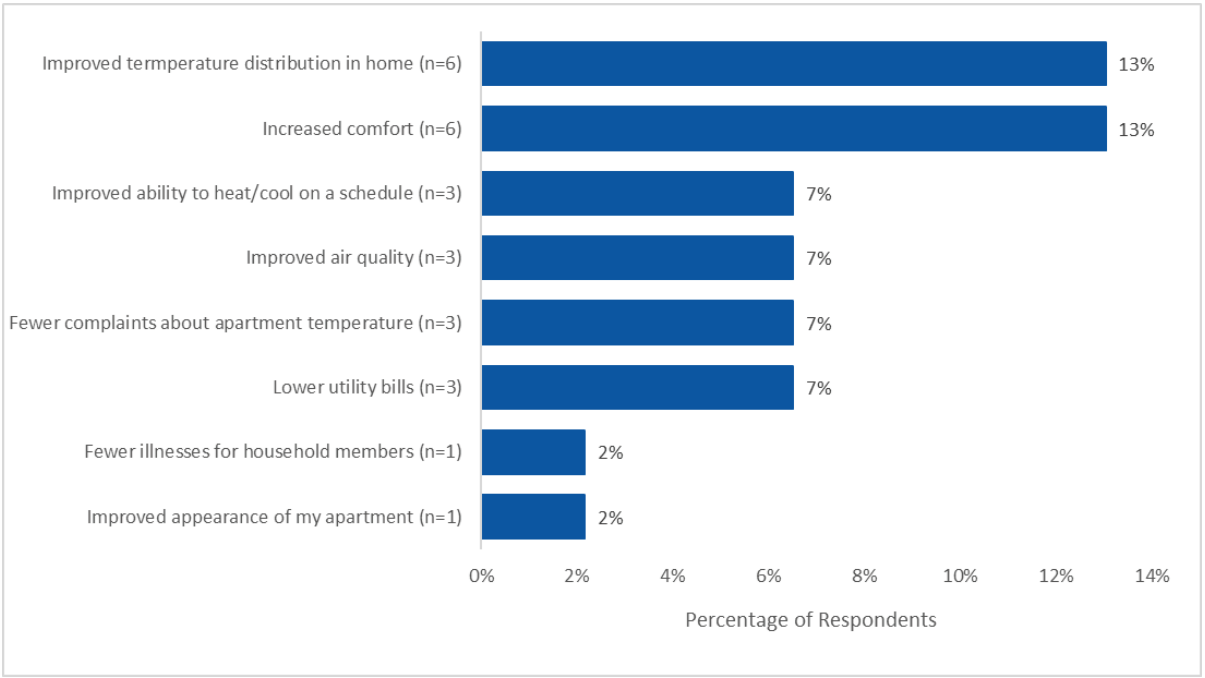
Figure 17. Multifamily Tenant Energy Bill Savings



Source: Heat Pump Multifamily Tenant Survey Guide Question D2. "Have you seen a lower-than-expected energy bill?"

Even with few respondents believing the CCHPs resulted in bill savings, a high number reported non-energy saving benefits of the CCHPs, primarily related to temperature distribution and comfort (Figure 18).

Figure 18. Non-Energy Benefits



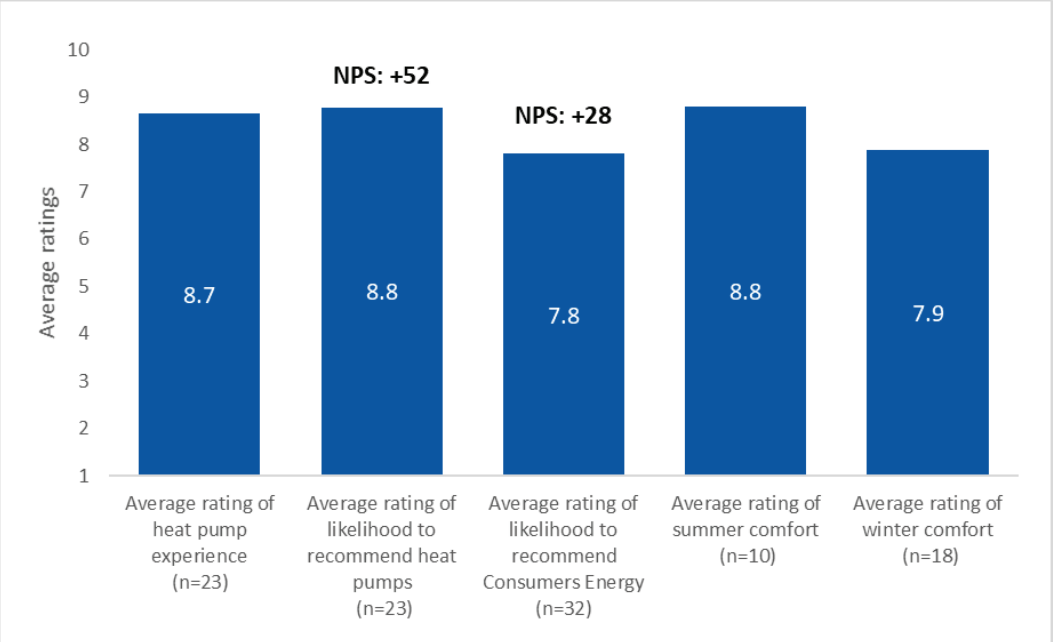
Source: Heat Pump Multifamily Tenant Survey Guide Question D3. "In addition to energy savings, if any, are there other benefits that you have experienced or observed from the installation of heat pumps?"

Satisfaction with the Offering and with Consumers Energy

Income-qualified multifamily tenants were satisfied with the CCHP experience, and generally felt that the heat pumps provided improved winter heating and summer cooling comfort. CCHP multifamily tenant participants reported an average rating of 8.7 regarding their overall experience with the heat pump, an average of 8.8 rating on likelihood to recommend a heat pump to a friend, and an average of 7.8 rating on likelihood to recommend Consumers Energy, all on a 10-point scale where 1 meant *unacceptable* or *extremely unlikely* and 10 meant *outstanding* or *extremely likely* (Figure 19). Respondents also reported an average rating of 8.8 regarding summer comfort and 7.9 regarding winter comfort.

Another key measure of customer satisfaction is the percentage of customers who are highly likely to recommend a product, service, or company after subtracting the percentage of customers who are highly unlikely to recommend that same product, service, or company. The net percentage of those willing to promote the product is the net promoter score (NPS), expressed as an absolute number between -100 and +100 that represents the difference between the percentage of promoters (respondents giving a rating of 9 or 10) and the percentage of detractors (respondents giving a rating of 1 to 6). The Cadmus team calculated a NPS for the two likelihood to recommend questions (likelihood to recommend the CCHPs and likelihood to recommend Consumers Energy – see Figure 19 below).

Figure 19. Satisfaction with Cold-Climate Heat Pump Experience and Comfort



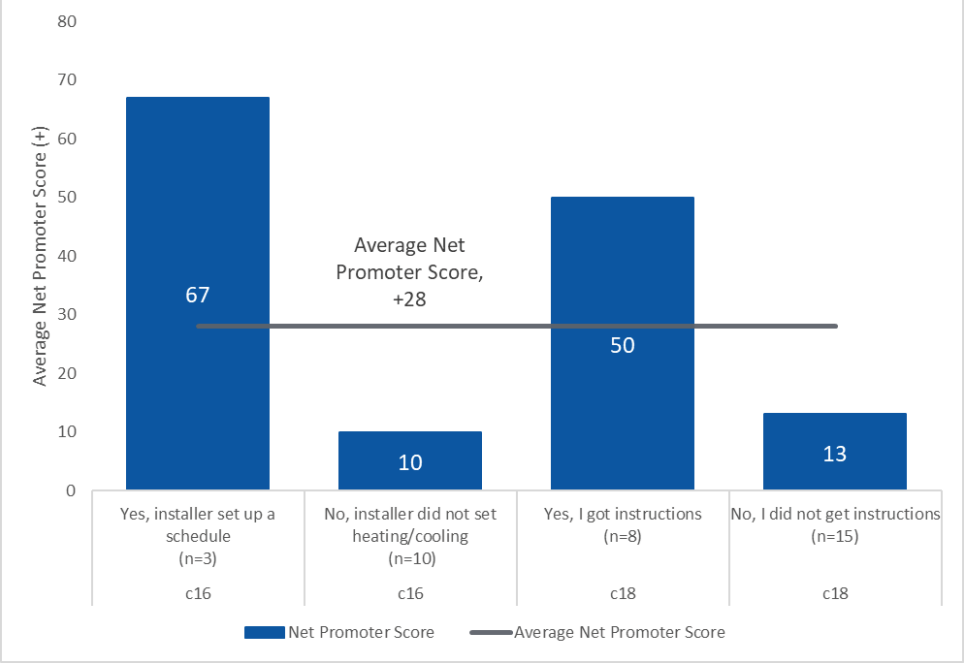
Source: Heat Pump Multifamily Tenant Survey Guide Questions E1, E2, A1, C9, and C6. Please see *Appendix E* for specific question wording.
This figure reflects combined average satisfaction ratings of heat pump experience and comfort.

The Evaluation team also calculated a NPS for the two likelihood to recommend questions (likelihood to recommend the CCHPs and likelihood to recommend Consumers Energy). As shown in Figure 19, based

on experiences with the heat pump, respondents were somewhat likely to recommend the heat pump to a friend. Though 14 respondents were promoters (providing ratings of 10) and only two were detractors, nine respondents did not provide a rating and seven were passives. The resulting NPS for the heat pump was +52. Sixteen respondents provided a 9 or 10 rating for likelihood to recommend Consumers Energy to a friend while seven provided ratings below a 7 and were classified as detractors (nine respondents were classified as passives). The resulting NPS for Consumers Energy was +28.

The Evaluation team compared the Consumers Energy NPS across different participant groups (Figure 20). Participants who provided low ratings on installation communication and instructions and provided verbatim feedback around lack of education materials and instructions were more likely to provide a lower overall Consumers Energy NPS. In fact, this cohort on average provided the lowest ratings of all participants. Additionally, participants who received instructions or had their heating and cooling schedule set by installation technicians had a higher NPS on average than both the survey average and the average of those who had no instructions or schedule set.

Figure 20. Average Consumers Energy Net Promoter Score and Installation Satisfaction



Source: Heat Pump Tenant Survey Guide Questions A1, C16, and C18. “How likely would you be to recommend Consumers Energy to a friend or family member if you had a choice in energy providers?” “Did the installation technician set up your heat pump on a heating and cooling schedule?” and “Have you been provided with instructions on how to setup and control your heating and cooling schedule on your heat pump?”

Open-ended responses regarding Consumers Energy were primarily positive in nature, though some were frustrated with Consumers Energy's service, mostly reporting high bills:

- "Great customer service and payment plans. But the cost in the winter is way higher than I think it should be."
- "My bill was all over the place last winter reaching almost $300 between two small school-aged kids who were gone most of the day and myself who unplugs everything."
- "Because I'm low income with social security income where there's no assistance help for my electric bill, the bill can be extremely expensive."

Nearly all positive responses cited great customer service and the ease of payment:

- "Service has been great for me in as long as I've been with them."
- "Good service and consistent customer service."
- "Very easy online payments and very easy outage center updates. It's also nice to have those text and email reminders about billing."

Impact Analysis

This section summarizes findings from the Evaluation team's statistical billing analysis, conducted to determine electric energy savings resulting from the Income Qualified Multifamily initiative. While the focus of the initiative and the billing analysis were on electric-heated properties (and therefore on electric impacts on heating use during the winter heating season), the Evaluation team also used the billing analysis to determine the electric energy impacts associated with summer cooling season. *Appendix B* has a detailed discussion of the methodological approach we used to determine the energy savings.

Key Findings

The Evaluation team estimated the electric energy impacts of CCHP installations separately for winter electric heating and summer cooling impacts. The Income Qualified Multifamily initiative participant electric savings results, presented in Table 10, show winter electric heating energy savings of 832 kWh, equivalent to 22.9% of baseline weather-sensitive electric heating use.

Table 10. Multifamily Income Qualified Heat Pump Electric Energy Savings

Group	Weather-Sensitive Electric Usage (kWh)		Weather-Sensitive Electric Savings		Precision at 90%
	Pre-Period	Post-Period	kWh	Percentage	
Winter heating	3,626	2,794	832	22.9%	±9%
Summer cooling	234	170	64	27.1%	±24%
Total Annual (Weather Sensitive)	3,860	2,964	896	23.2%	±8%

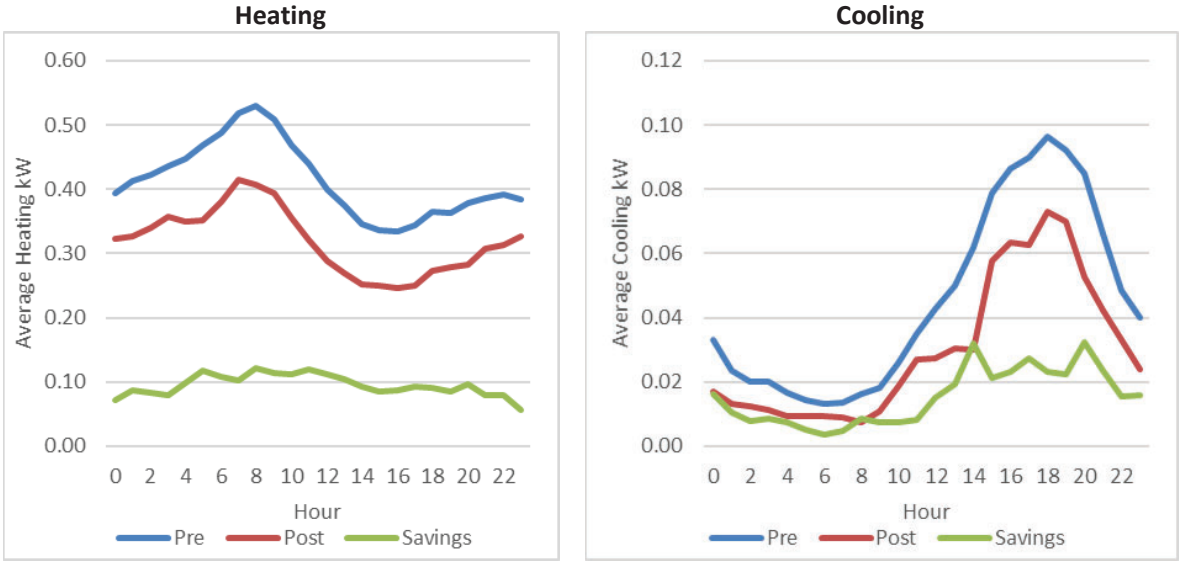
Source: Evaluation team billing analysis.

The billing analysis estimate of 64 kWh savings per unit during the summer cooling season reflected a similar percentage reduction in weather-sensitive electric usage attributable to the CCHPs (at 27%

relative to the 23% for winter heating). The heating electric analysis produced savings estimates within the ±10% precision threshold at a 90% confidence interval and therefore the results were statistically significant. Given the lower cooling load and therefore more variable signal, the cooling savings were outside the ±10% precision target. Overall, the Income Qualified Multifamily initiative resulted in a statistically significant annual reduction of 896 kWh for each participant tenant unit, representing 23.2% of the annual weather-sensitive electric energy use and translating into approximately $147 in annual bill savings for each CCHP participant.

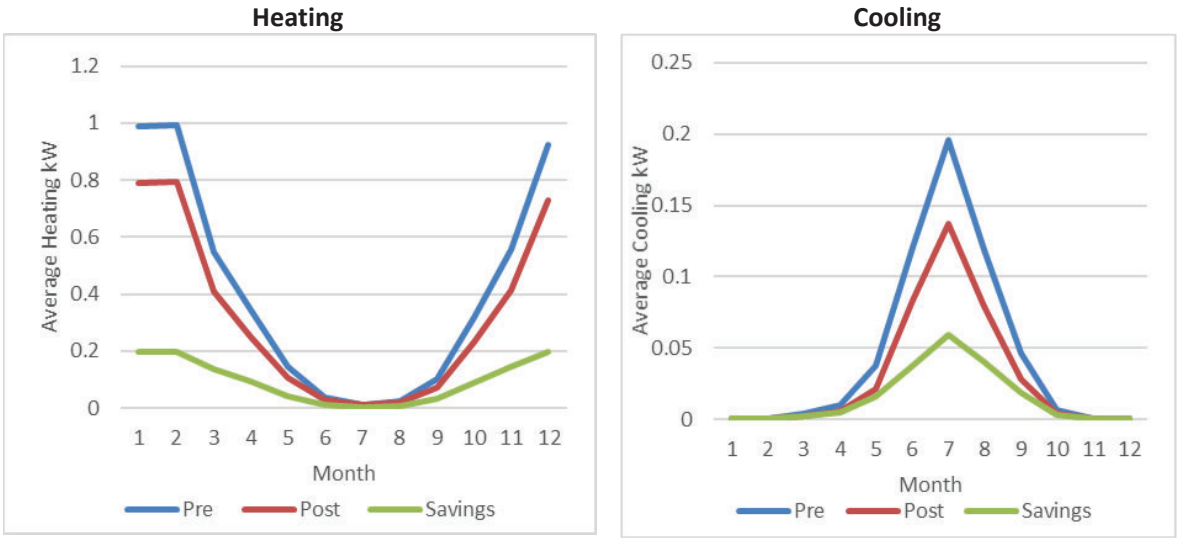
An examination of the heating and cooling load shapes and accompanying savings profile offers insight into how the CCHP impacted heating and cooling usage. Figure 21 shows the average winter and summer daily load shape and resulting CCHP savings profiles. In the winter, participants' CCHP electric energy savings were relatively consistent throughout the day. In the summer, the CCHP cooling savings were coincident with the cooling load periods of mid-to-late afternoons.

Figure 21. Participant Hourly Heating and Cooling Load and Resulting Savings



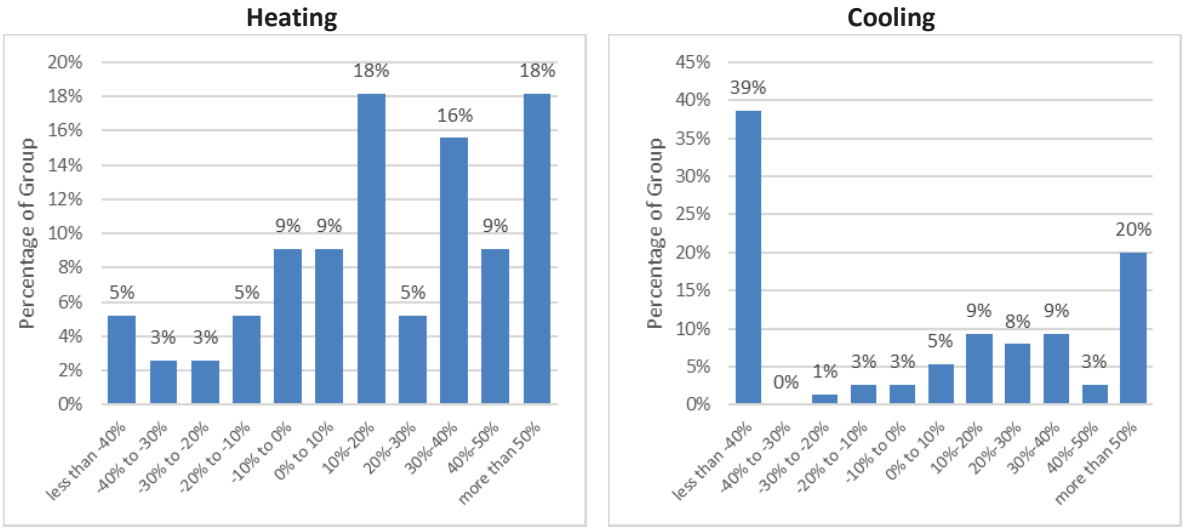
An examination of the average *monthly* load and savings profiles also showed that the savings were consistent with the monthly load shapes (Figure 22).

Figure 22. Monthly Heating and Cooling Load and Resulting Savings



The Evaluation team also explored the variability of savings across the tenant units by grouping the percentage of tenant units according to decile savings bins (incremental steps of 10% savings; see Figure 23). More than 40% of the Income Qualified Multifamily tenants saved over 30% of their pre-installation electric energy during the winter heating season, while the largest group of customers (18%) saved over 50%. On the summer cooling analysis, close to 40% of Income Qualified Multifamily customers had a net increase in summer electric use. These customers likely lacked any pre-installation cooling equipment (no room ACs) or were unlikely to have used their equipment. The second largest group of customers were also the highest saving group, with 20% of the tenants saving over 50% of their pre-installation summer cooling electricity usage.

Figure 23. Percentage Distribution of Annual Heating and Cooling Savings by Savings Bin



Benchmarking of Results

The Evaluation team compiled results from three recent multifamily heat pump retrofit program evaluations in other regions to understand how the results compared to the Consumers Energy Income Qualified Multifamily initiative. A majority of the evaluations were focused on income-qualified properties. As shown by the summary benchmark data in Table 11, the Income Qualified Multifamily initiative findings are consistent with other multifamily income-qualified billing analysis results.

Table 11. Benchmarking of Multifamily Heat Pump Billing Analysis Results

Utility and Program	Percentage Savings	Home Type	Income	Analysis Type
Consumers Energy Income Qualified Multifamily initiative	**23.2%**	**Multifamily**	**IQ**	**Billing Analysis**
2020 Commonwealth Edison Multifamily Income-Qualified Heat Pump pilot (full report not yet public but summary report is here)	25%	Multifamily	IQ	Billing Analysis
2016 Efficiency Maine Low-Income Multifamily Weatherization program (report)	22.2%	Multifamily	IQ	Billing Analysis
2014 Connecticut Energy Efficiency Fund Home Energy Services (Income Eligible) (report available online)	11% [a]	Multifamily	IQ	Billing Analysis
2014 Energy Trust of Oregon Multifamily Ductless Retrofits (report available online)	15% [a]	Multifamily	Any	Billing Analysis
Puget Sound Energy Heat Pump Dealer Channel (not public)	18% [a]	Single Family	Any	Billing Analysis

[a] This represents the percentage of annual load, not the percentage of weather-sensitive load (which was not reported).

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Commercial and Industrial Cold-Climate Heat Pump Pilot Findings

Consumers Energy developed its Commercial and Industrial Cold Climate Heat Pump Pilot initiative in 2020 in response to the 2020 Consumers Energy Settlement Agreement with the Michigan Public Service Commission and other stakeholders. Beginning in early 2021, Consumers Energy launched the initiative targeting small commercial and industrial customers, defined as customers with facilities under 20,000 square feet. Initiative staff reached out to customers who did not have access to natural gas or were suspected to have propane heat. Staff then helped these customers choose a contractor to install a CCHP, addressed any questions the participants had throughout the installation process, and provided significant financial support to install new CCHPs; all but one customer had the entire cost fully covered.

For this research, the Evaluation team conducted in-depth telephone interviews with initiative participants to address several key research objectives:

- Explore key factors in customer decision-making regarding CCHP installations
- Explore customer experiences during the CCHP installation process
- Explore customer experiences using their CCHP
- Explore customer experiences with the initiative offering
- Identify opportunities to best support CCHP technology moving forward

In the fall of 2021, the Evaluation team conducted in-depth interviews with seven of the nine initiative participants, asking about heat pump technology awareness and motivations for participation, as well as participant experiences and satisfaction throughout the initiative process and with their new heat pump technology. During the winter of 2021/2022, the Evaluation team also metered the equipment to assess energy savings. Findings from this research are found in the 2021 Cold Climate Heat Pump Pilot Impact Evaluation Memo submitted as part of Consumers Energy's 2021 reconciliation. Metering for the 2022 cooling season is still in progress as of the writing of the report, and analysis and reporting will take place later in 2022.The remainder of this section presents findings from the participant interviews.

Participant Interviews Findings

In Fall 2021, the Evaluation team conducted in-depth interviews with seven Small C&I Initiative participants who were either the business owner or a key decision-maker related to the business. The subsections below describe how customers heard of and then decided to participate in the initiative offering, followed by installation experiences, heat pump use experiences, and overall initiative experiences and satisfaction. Additional details are available in the *C&I 2021 Cold Climate Heat Pump Pilot Customer Interview Results Presentation* submitted as part of Consumers Energy's 2021 reconciliation.

Decision-Making Processes

The Evaluation team asked participants about their awareness and understanding of heat pump technology, their plans to replace existing heating equipment, as well as their concerns, considerations, and motivations for installing the heat pumps.

Participants in the Small Commercial initiative were generally not familiar with heat pumps prior to being contacted by Consumers Energy staff. Over two-thirds of respondents (71%; n=5) were *not at all familiar* with heat pumps prior to the initiative. One respondent said they were *somewhat familiar* and had read some articles about heat pumps, but not enough to have purchased a heat pump without the support from the initiative. Another respondent said they were *very familiar* with the technology, but was under the impression that heat pumps were not suitable for Michigan winters.

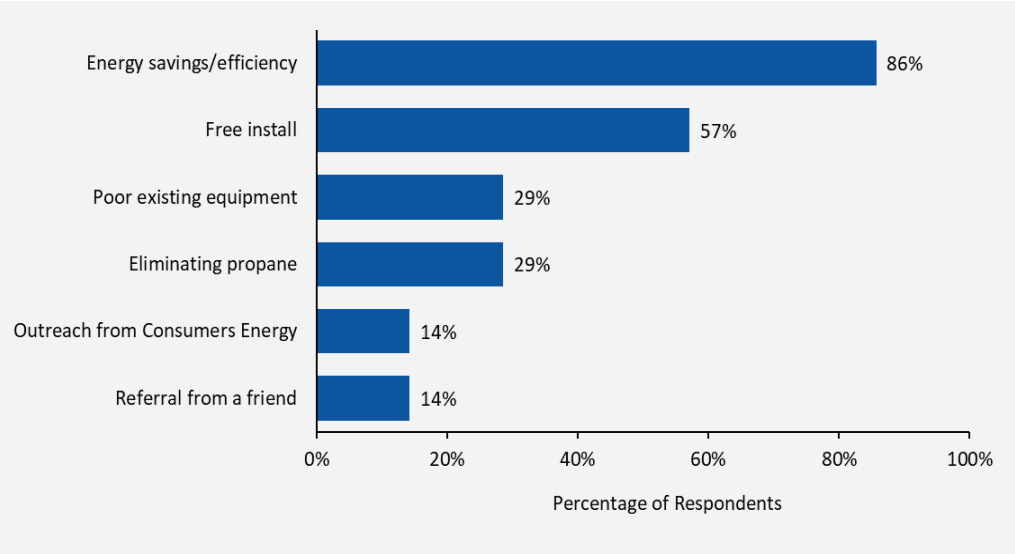
When asked about their existing heating and cooling equipment, all respondents reported having a propane furnace prior to installing their heat pumps, and 86% (n=6) had central AC. While four respondents had no immediate plans to replace their existing equipment, 43% (n=3) had planned to replace their heating equipment within the next one to three years, and all three would likely have replaced their furnace with a new propane furnace. This finding suggests that customers likely would not have considered a heat pump as an option if not for the initiative, despite some respondents reporting low satisfaction with their propane service.

When asked about their concerns and considerations when deciding to install a heat pump, respondents were primarily concerned about cost and technical considerations, while two respondents (29%) initially thought the offer was a scam: one said, “My main thing was, to be honest, I was scratching my head if it was too good to be true. I was suspicious; there are so many scams. My biggest concern [was that] I just wasn’t quite sure what was actually going on. It’s quite a good deal to get that kind of equipment.”

Respondents’ cost considerations included not knowing how much more money they would pay by switching to a heat pump, as well as how much lower their energy bill would be and how much less energy they would use. Three respondents also expressed concerns about how reliable the heat pumps would be during the winter. The following quote exemplifies this sentiment and demonstrates how this hesitancy is related to a lack of knowledge about CCHPs: “…Without knowing about the technology, we were a little concerned…about how well would the systems work in the really cold weather.”

When asked what motivated them to install their heat pump, respondents reported several motivations, mainly saving energy and the free installation, followed by the fact that the cost was largely if not completely covered by Consumers Energy (Figure 24).

Figure 24. Respondent Motivations to Install Heat Pumps



Source: Heat Pump Commercial Interview Guide Question C4. "What motivated you to agree to install the heat pump?" (n=7; multiple responses allowed)

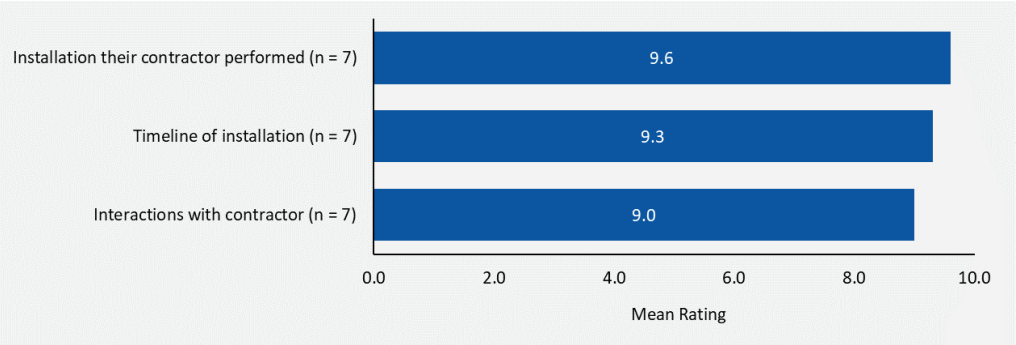
Installation Experiences

The Evaluation team also asked respondents about their experiences with finding a contractor and with having the heat pump installed. All respondents reported that it was easy to find a contractor, and none asked for multiple bids. About half of respondents (43%; n=3) preferred to use their own contractor and one respondent (14%) asked a friend who had also participated in the initiative for their contact. The other three respondents (43%) relied on contractor contacts provided by Consumers Energy: two chose a contractor they were familiar with from the list (and, as mentioned previously, Consumers Energy tailored this list to include trade partners they knew had experience with heat pumps). These findings indicate that the initiative resources for finding a contractor were effective.

Overall, respondents reported having a positive experience with their contractor, with 86% (n=6) saying they would use the same contractor again. All the respondents also reported that the contractors they worked with appeared to be knowledgeable about heat pumps, and 57% (n=4) said the contractor was *very knowledgeable*: "Extremely [knowledgeable] and very helpful and explained it all to me very well… They were fast, efficient, and did exactly what they were going to do in the time they said they were going to do it. They did a great job."

Average satisfaction with contractor interactions was a 9 on 10-point scale, where 1 meant *unacceptable* and 10 meant *outstanding* (as shown in Figure 25). Though respondents were generally satisfied with their contractors, two of the seven respondents (29%) expressed some dissatisfaction. One of these respondents specified that the contractor should have been more communicative about the project schedule and timeline but said they would still hire the contractor again because they would not know who else to hire. The other respondent was less satisfied with their interactions with the contractor and were not sure they would hire them again.

Figure 25. Installation Experiences Satisfaction Averages



Source: Heat Pump Commercial Interview Guide Questions G1a, G1b, and G1d. Please see *Appendix F* for specific question wording.

Respondents were also satisfied with the timeline of their installation. While about half of respondents (57%; n=4) reported some delay with their project timeline, it did not impact their overall satisfaction. However, some reported that if the installation had occurred during a time when they needed their heating or cooling, they would have been more dissatisfied. Heating or cooling needs were not pressing since these customers either had working equipment or their installation was completed in the shoulder season, as evident by the following statements:

- "It might have been different if we didn't have heat or air and every day was a struggle, but it was early spring… so it wasn't an issue, so we weren't pressed to hurry up and get this into service."
- "I'm glad they didn't do it in the winter, because then I would have been irritated [with the delayed project timeline]."

Most of the heat pump installations went smoothly, with respondents rating their satisfaction with the installation process as an average of 9.6 out of 10, as shown in Figure 25. When asked if there were any challenges with installing their heat pump, only two respondents reported some minor challenges related to the equipment not functioning properly at first and unforeseen installation issues. All respondents said that they received a new thermostat as part of their CCHP installation, and about half (43%; n=3) required new duct work. Slightly more than half of respondents (57%; n=4) reported that they have a back-up heating system in addition to the CCHP system. Of those four, two kept their old heating and cooling equipment, one just kept their old back-up heating, and one installed a new propane furnace as a back-up.

Experiences Using Heat Pumps

Due to the timing of this initiative and the research effort, respondents had primarily used their heat pump during the summer months and had used only the cooling function; however, some respondents (71%; n=5) reported that the heating function had come on during colder mornings in September or said they had been able to use the heat briefly in early spring. In general, respondents were very satisfied with their new heat pump and its operation, with an average satisfaction rating of 9.3 out of 10. While respondents were already generally satisfied with the equipment, a few customers noted being hesitant

to give the heat pump a higher rating until after using the heating function more consistently in colder weather. The Evaluation team conducted follow up interviews with Small Commercial initiative participants as part of on-site impact evaluations completed following the 2021/2022 winter heating season to assess participant experiences with the heat pumps in cold weather. [17]

Despite high satisfaction with heat pump performance, almost half of respondents (43%; n=3) reported some minor issues with their heat pumps, including not cooling down to the expected temperature and two issues with the installation that required a contractor to fix. The biggest challenge customers reported was needing to learn how to use their new smart thermostat; this finding was echoed in the winter heating impact analysis, which revealed that some customers would benefit from additional training or support to optimize heat pump controls and settings to maximize savings. These findings suggests that customers easily adapted to their new technology but could use some higher touch support during the first few weeks or months after installation to confirm that all the equipment is performing well and that the customer knows how to use the equipment properly.

Initiative Experiences and Satisfaction

When asked about their overall initiative experience, most respondents said they were *very satisfied* with their participation in the initiative. Most respondents (86%, n=6) had initially learned about the initiative offering from Consumers Energy staff and all seven reported that they had received excellent support throughout their participation. While respondent motivations for deciding to participate in the initiative included the fact that the equipment and installation were free, the support and persistence from Consumers Energy staff was also a motivating factor.

> "Just the willingness that they had to do this for just a small [facility] was huge […] People don't just give stuff away, and [a new heating system] was definitely something that was needed, and we would have had to purchase it in the future."
>
> -Respondent

Respondents' overall satisfaction with the pilot was an average of 9.9 out of 10, and 86% of respondents (n=6) *strongly agreed* that Consumers Energy made it easy to participate in the initiative. When asked if they were likely to recommend Consumers Energy to a friend or colleague if they had a choice in energy providers, most respondents (71%; n=5) said they were extremely likely to do so. The two respondents who gave lower ratings said that it was only because their utility is not something they really think or talk about. One satisfied respondent compared Consumers Energy to the utility that provides electricity at their home: "I've always had great service with Consumers [Energy]. I've had less outages and …anything I need for my business, I'm able to get immediate responses."

[17] TRC. 2022. C&I 2021 Cold Climate Heat Pump Pilot Impact Evaluation Memo.

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Appendix A. Survey and Interview Methodology and Details

This appendix provides survey and interview details and methodologies by initiative or stakeholder.

Contractor Interviews

Consumers Energy provided the Evaluation team with a sample of 177 contractors who had engaged with Consumers Energy HVAC energy waste reduction offerings at some point, but who had not participated in the CCHP Initiatives. The sample did not include any information regarding the number or type of projects completed by the contractor, so the Evaluation team was unable to stratify the sample in any meaningful way. As such, recruitment of contractors proceeded randomly until research quotas were satisfied. We interviewed a total of 11 contractors for this research.

Table A-1 includes contractors' company information such as type, number of projects per year, and products offered.

Table A-1. Interviewed Contractor List

Company Location	Customer Base	Number of Projects/Year	Average Heat Pump Installation/Year
Ada	Primarily residential, more high-end homes	~100	<5 ducted systems >20 mini-splits
Allen Park	Residential multifamily, some single family, very little commercial	1,000–1,500	75 since last fall
Allendale	Data not collected	Data not collected	Data not collected
Benzonia	90% to 95% residential, lots of big homes on shore of Lake Michigan used as seasonal residences; a little bit of multifamily, a little low income	200 installs	20–30
Dearborn Heights	Mostly residential, some multifamily	100	3 last year
Jackson	50% residential, 50% commercial	200–225	6–8 ducted systems >50 mini-splits
Livonia	Primarily (75% or more) income-qualified multifamily, with client that is the largest affordable housing provider in Michigan	5–10 projects per year 100–300 pieces of equipment	10–20 mini-splits per year (primarily server rooms and elevator machine rooms)
Okemos	60% residential and 40% commercial, lots in the city, also lots of dual-fuel applications with propane and lots of air-to-air and geothermal projects	~1,000	~100 in 2020, 80% air-to-air 24 mini-splits in the past year
Parma	Residential and some multifamily (very little commercial)	150–200 pieces of equipment	<10
Sparta	75% residential, commercial is mostly service maintenance, with a rare design/build	~100	12–15 per year for ASHPs and mini-splits.
Warren	50% residential and 50% commercial	200	<5

Distributor and Manufacturer Interviews

The Evaluation team interviewed five distributors and two manufacturers involved in the production and distribution of CCHPs (including mini-split heat pumps) in Michigan. We fielded the interviews via telephone, and each took 30 to 45 minutes to complete. The team recorded and transcribed each interview to assist with our analysis. To motivate manufacturers and distributors to participate, we offered a $75 incentive to each respondent in the form of an Amazon, Target, or Meijer gift card or a donation to a local United Way.

Sampling

For this effort, the Evaluation team specifically targeted manufacturers who have supplied equipment for Consumers Energy programs and associated distributors in Michigan that supply CCHPs produced by these manufacturers. The list of manufacturers and distributors interviewed is shown in Table A-2.

Table A-2. Interviewed Distributor and Manufacturer List

Company Type	Role of Interviewee	Primary Brands Offered	Primary Types Offered	States/Regions Served
Manufacturer	Manager, Utility & Efficiency Programs	(Confidential)	Mini-split	Central U.S.
Manufacturer	Regional Representative	(Confidential)	Mini-split	MI, OH, PA, WV
Distributor	President	Robur	Absorption	MI, OH, IN
Distributor	Director of HVAC Services	Mitsubishi, Rheem, Trane	Mini-split	MI, OH, Eastern U.S.
Distributor	Territory Manager	Trane, Mitsubishi	Mini-split, unitary	MI
Distributor	Regional Sales Manager	LG, Rheem, Bosch	Mini-split, unitary	MI, OH, IN, PA, WV
Distributor	Owner	Daikin, Amana	Mini-split, unitary	MI, WI, IL, IN, OH, PA

The team sampled distributors from a contact list provided by Consumers Energy staff as well as from internet searches for distributors associated with key manufacturers. Additionally, the Evaluation team asked for referrals for distributors during interviews with contractors. We targeted distributors such that representation across manufacturers was roughly equal (ensuring that interviewed distributors do not represent one manufacturer more than another).

Recruiting

The Evaluation team reached out to manufacturers and distributors by phone to schedule interviews. During phone recruitment, we explained the research and provided an Evaluation team contact person so the organization could reach out if they had additional questions or were interested in scheduling an interview. The team primarily used email to recruit referrals, which similarly included an explanation of the research and a request for scheduling an interview.

Profile of Distributors and Manufacturers

Table A-2 above shows respondent information including company type, the role of the interviewee at the company, primary brands offered, types of CCHPs offered, and regions served. Most interviewees represented mini-split CCHP technology and were responsible for operations in several states.

Residential Market Rate Participant Surveys

The Evaluation team sent a survey invitation to the census of 29 Residential Market Rate pilot participants in November 2021. The email survey invitation included a $15 incentive for taking the survey. The Evaluation team sent two reminder emails; after one week and after two weeks. Nine of the 29 participants completed the survey, for a 31% response rate: with such a small sample size, the results should be interpreted with caution and only viewed as directional indications (not intended to be analyzed with statistical confidence).

Income Qualified Multifamily Property Manager and Owner Interviews

The Evaluation team conducted in-depth telephone interviews with three site contacts (a construction manager, a resident manager, and an owner) in November 2021. Each interview lasted approximate 30 minutes. We targeted owners and managers of income-qualified multifamily properties who had participated in the Consumers Energy Income Qualified Multifamily initiative. Franklin Energy provided PMO contact information, including email address and phone numbers, for Evaluation team outreach and recruitment.

The Evaluation team initially distributed emails to six property site contacts and attempted phone recruitment for the seventh due to a missing email address. Though the team made three email attempts, the emails did not result in any successful recruitment for the interviews. The Evaluation team then pivoted to making recruitment calls from Monday through Friday, mid-morning to early evening, calling each number a maximum of five times.

With an interview target for a census (seven) of participating PMOs, the actual number of three interviewed PMOs was consistent with expectations, even with an increased incentive of $150 to make the interview more attractive for potential participants.

Income Qualified Single Family and Multifamily Participant Surveys

The Evaluation team collected feedback from 32 multifamily tenant surveys in November 2021. The email survey invitation included a $15 incentive for taking the online survey. We targeted tenants of income-qualified multifamily properties who had participated in the Consumers Energy heat pump offering. The Evaluation team did not have access to participating tenant contact information, so we attempted to identify tenants through two distinct efforts. First, the team relied on existing income-qualified tenant records to match CCHP properties based on physical address. Using this approach, the team identified 46 potential income-qualified multifamily tenants to recruit. Second, during the team's interviews with multifamily PMOs, we asked and all three PMOs if they were willing to distribute the survey recruitment email to their tenants. This second approach resulted in the potential for 90 additional tenant respondents, though the Evaluation team is unsure of the final count of emails distributed by the PMOs.

The Evaluation team solely relied on email distribution to recruit tenants for the online-only survey. Though the team made three email attempts for the address-matched income-qualified tenant group, the emails combined with the PMO email recruitment effort resulted in 32 successful recruitments for the surveys, for a response rate of 24% (32 of 136).

Small Commercial Participant Interviews

The Evaluation team conducted in-depth telephone interviews with seven business owners and decision-makers in September and October 2021. Each interview lasted approximately 30 to 45 minutes and we offered respondents a $75 gift card for their time. We targeted owners and decision-makers of small commercial and industrial facilities (<20,000 square feet) who had participated in the Consumers Energy Small Commercial initiative offering. Consumers Energy provided these decision-makers' contact information, including email address and phone numbers, for Evaluation team outreach and recruitment. The interview guide was reviewed and approved by Consumers Energy staff to ensure that questions were consistent with their expectations and reflected the issues of interest to Consumers Energy.

The Evaluation team recruited customers via email and phone. Due to the small sample size of nine participants, we attempted to recruit the entire sample with a minimum goal of five completes. The Evaluation team was able to recruit seven of the nine participants, with a response rate of 78%. An eighth participant was interested in participating but their heat pump had not been installed yet, so they were not able to answer questions about the full experience. The ninth participant was unreachable after a total of five contact attempts via email and voicemail.

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Appendix B. Impact Analysis Methodology and Details

This appendix provides the methodology and details related to the Residential Market Rate pilot engineering analysis and the Income Qualified Multifamily initiative billing analysis.

Market Rate Engineering Methodology

The Evaluation team conducted an engineering analysis of the impacts from the Residential Market Rate pilot and relied on MEMD assumptions and information we had collected on customer data such as such as home vintage, presence of central cooling, installed system COP at 5°F, rated HSPF and SEER, tonnage, and other data. The Evaluation team relied on the MEMD weighting tool, which generates single measure outputs based on home vintage, climate zone, sizing, and efficiency levels.

The MEMD building simulation data provided end-use level consumption details broken out by the seven Michigan climate zones (Alpena, Detroit, Lansing, Muskegon, Saginaw, Sault Ste. Marie, and Traverse City) and three building vintages (old, average, and new). The Evaluation team used the MEMD building simulation end-use consumptions for ASHP heating, ASHP electric resistance back-up heating, and ASHP cooling to calculate pre– and post–CCHP equipment consumption on a per-ton basis. We then adjusted these end-use consumptions using COP from ASHP federal standard HSPF and SEER values to reflect site-specific equipment. We used several types of CCHP-collected site data in the analysis:

- Home vintage
- Presence of central AC
- Home heating fuel type
- Home heating equipment type
- Premise zip code
- CCHP details: quantity, COP at 5°F, HSPF, SEER, and tons

Since existing space heating equipment data collection was limited to fuel type, the team assumed that existing equipment represents federal standard equipment (in AFUE) and represents a 50/50 average of boilers and furnaces, if applicable. The Evaluation team created this split because the data field for system type collected was either “Furnace/Boiler” or “Resistance.” The difference in federal standard efficiency is minimal: 0.8 for furnaces and 0.82 for boilers. Therefore, the team used 0.81 AFUE.

We also assumed that existing central cooling equipment represents the federal standard SEER value. For homes without central cooling, we assumed that a portion of homes use room or window AC units to provide a portion of cooling, and we based this portion of homes on *2015 Residential Energy Consumption Survey*[18] data for the East North Central census division. The Evaluation team used data

[18] U.S. Energy Information Administration Residential Energy Consumption Survey 2015 Data Website: https://www.eia.gov/consumption/residential/data/2015/

from the Consumers Energy 2021 *Electric Energy Waste Reduction Potential Study*[19] to develop a ratio of room AC tonnage for single family homes when compared to a central system (since the room AC unit likely did not provide cooling load equivalent to the CCHP system). Like with central ACs, we assumed the room AC efficiency to represent the federal standard EER value.

Since no sizing information was collected on the sites about the existing HVAC systems, the Evaluation team assumed equivalent kBtu per hour heating or cooling tonnage as the CCHP, except for existing room AC sizing (for which we made an adjustment). Therefore, results only reflect offset heating and cooling load by the CCHP, and not total household heating and cooling load.

We used two data points to map MEMD 2019 data to the site-specific data: "Approximate House Age" and "Premise Zip." The household age was a one-to-one match with MEMD vintages, and therefore was a simple mapping lookup. The Evaluation team mapped the zip codes nearest to the available MEMD weather station based on distance and engineering judgment for weather impacts. With these two site-specific data points—vintage and zip code—we were able to map the MEMD 2019 building simulation consumptions to each specific site.

To adjust the MEMD 2019 ASHP end-use consumptions to reflect the existing equipment on a per ton basis, the team applied COP adjustments using the federal standard definitions outlined above. To adjust the MEMD 2019 ASHP end-use consumptions to reflect the CCHP equipment, we performed a more detailed analysis (as additional equipment data was available). Using typical meteorological year version 3 (TMY3) 8760 hourly data for each MEMD modeled reference city, we performed hourly bin analysis to determine hours based on temperature bins in 5°F buckets. Assuming the HSPF value reflected performance at 47°F, the team developed a linear relationship using the COP at 5°F system performance data. We capped this linear relationship during cold temperatures to not be less than 1 COP, representing 100% electric resistance performance. Using the hourly bin analysis data by 5°F buckets and assuming CCHP heating did not occur above 65°F, the Evaluation team developed a weighted average CCHP HSPF efficiency to represent annual heating performance of the CCHP specific to the unit installed. We then used the weighted average CCHP HSPF and SEER values to adjust MEMD 2019 ASHP end-use consumptions to reflect CCHP performance on a per-ton basis. In order to represent total heating and cooling load, we multiplied the CCHP installed tonnage by the pre/post heating and cooling loads per ton.

The Evaluation team relied on Consumers Energy 2021 residential natural gas and electric marginal rates (per kilowatt-hour and per therm), which include all surcharges for single-family customers. The team used previously developed load shapes to reflect equipment usage during peak and non-peak periods for the electric bill impacts. We created annual electric fuel costs by applying each specific equipment type's consumption load shape to the peak and off-peak rates. For fuel oil and propane costs, the

[19] 2021 Energy Waste Reduction Electric Potential Study Report: https://cadmus.sharepoint.com/sites/collaboration/6409-P01/ces/Shared%20Documents/Final%20Reports/2021/Electric%20Potential%20Study/2021%20Energy%20Waste%20Reduction%20Electric%20Potential%20Study%20Report%20FINAL%202021.06.10.pdf

Evaluation team used the latest Michigan monthly data from U.S. Department of Energy resources. These fuel costs utilized in the impact analysis are shown below in Table B-1.

Table B-1. Market Rate Fuel Costs Utilized in Impact Analysis

Fuel Type	Cost
AC_Central Loadshape - Electricity with Surcharge	$0.18
AC_WallWindow Loadshape - Electricity with Surcharge	$0.18
ASHP Loadshape - Electricity with Surcharge	$0.17
ZONAL_ER_HEAT Loadshape - Electricity with Surcharge	$0.16
AC Central Load Shape - Electricity with Surcharge	$0.18 per kWh / $52.48 per MMBtu
AC Wall Window Load Shape - Electricity with Surcharge	$0.18 per kWh / $52.19 per MMBtu
ASHP Load Shape - Electricity with Surcharge	$0.17 per kWh / $48.57 per MMBtu
Zonal Heat Load Shape - Electricity with Surcharge	$0.16 per kWh / $48.18 per MMBtu
Propane	$2.44 per gallon / $26.71 per MMBtu
Fuel Oil	$3.10 per gallon / $22.56 per MMBtu
Natural Gas	$7.91 per thousand cubic feet / $7.62 per MMBtu

Sources: U.S. Energy Information Administration. Accessed on January 14, 2022. Heating Oil and Propane Update https://eia.gov/petroleum/heatingoilpropane/#itn-tabs-1
Electric and natural gas rates used from Consumers Energy.

Multifamily Billing Analysis Methodology

To estimate electric energy usage changes within the Income Qualified Multifamily initiative projects, the Evaluation team designed and conducted a statistical billing analysis. The team relied on historical advanced metering infrastructure (AMI) interval data to estimate facility-wide and per-tenant-unit savings associated with CCHP installations using the Princeton Scorekeeping Method. The team incorporated TMY3 data to normalize usage and control for weather. We also included a nonparticipant comparison group, selected from other income-qualified electrically heated multifamily nonparticipants to control for the impacts of nonprogrammatic factors (such as changes in economic conditions including COVID-19–related behavior changes).

Data Sources

The Evaluation team requested and compiled participant and household data for the CCHP billing analysis from several sources:

- ***Heat pump initiative tracking data.*** The team received initiative tracking data from the implementation contractor to identify CCHP properties. These initiative tracking data included all participants from March 2020 to December 2020, including property name, participation dates, building square footage, and heat pump efficiency and capacity ratings. The tracking data did not include specific tenant unit addresses or the specific account information connected with each tenant.
- ***Multifamily composite database.*** The team developed a multifamily database to identify multifamily properties based on property size for prior 2020 evaluation research, which we used to identify all unique addresses (and all accounts associated with each property), including tenant units.

- ***Electric AMI data.*** Consumers Energy provided electric AMI data for all properties that had identifiable account data. This included meter read dates and times and all kilowatt-hour usage, by account, between June 2019 and September 2021.
- ***Michigan weather data.*** The team collected average hourly temperatures from June 2019 through September 2021 for four weather stations corresponding to the nearest monitoring station locations associated with CCHP participants. We matched hourly heating degree hours (HDHs) and cooling degree hours (CDHs) to AMI data read dates and times, and compiled hourly TMY3 15-year normal weather averages from 1991 through 2005 from the National Oceanic and Atmospheric Administration to assess energy usage under normal weather conditions.

Data Processing

The Evaluation team conducted several data processing steps to review, validate, and transform the raw AMI and tracking data into an analysis dataset:

- Imported and cleaned the tracking, AMI, and weather station datasets into Statistical Analysis System software
- Merged tracking and AMI datasets using account ID
- Filled in missing or zero AMI data readings with averages based on similar day-types or as the average of the previous and following hours
- Checked the hourly AMI histories for problems such as vacancies, outliers, and too many missing/interpolated readings
- Mapped each property to the nearest weather station using the property zip code
- Used hourly temperatures to determine variable base HDHs and CDHs for each station
- Merged the HDHs and CDHs onto the AMI and tracking data, using respective dates and times for each account
- Matched TMY3 HDHs and CDHs from the nearest station to weather-normalize the AMI data

Participant and Nonparticipant Groups

For the AMI analysis, the Evaluation team assigned properties into participant and nonparticipant groups. To be selected for the participant group, all multifamily heat pump properties had to have a continuous nine-month period of available usage data both before and after their participation in the pilot. The team used a rolling specification to assign pre- and post-periods, identifying a range of months around the installation period for each participant. Starting with a census of participants from the March through December 2020 period (initially seven properties), the Evaluation team identified a final participant group for analysis (after screening for participants who had at least nine months of pre-period and post-period billing data). We conducted account-level reviews of pre- and post-period usage for all individual participants to identify anomalies (periods of vacancies or other anomalies) that could bias the results. The team also applied additional screening criteria, described in detail in the *Data Screening and Model Attrition* section.

The team used a comparison group of nonparticipants to account for exogenous factors that may have occurred coincident with heat pump initiative activities. These factors can include macroeconomic effects, COVID-related behavior or occupancy changes, or other interactions that may have affected energy usage outside the heat pump influence. The Evaluation team identified comparison groups using customers who we had identified as living in income-qualified electrically heated multifamily properties. After creating the eligible group of nonparticipants, we further refined the nonparticipant group by matching each property to a participant property based on pre-installation usage. This assisted us in creating groups with baseline usage profiles as similar as possible to those of participants.

Disaggregation

Consumers Energy had the Evaluation team focus the heat pump analysis on electric-heated properties to create savings associated with reducing electric heating and cooling loads. Because of the focus on electric heating and cooling loads, the Evaluation team disaggregated the billing data to isolate the weather-sensitive electric heating and cooling usage from overall annual electric usage (which may include water heating, cooking, plug load, and lighting usage). First, we estimated weather-normalization models for each customer in the pre- and post-installation periods using actual observed weather data. Then we estimated the weather-sensitive components of electric usage using TMY3 data. Finally, we estimated the heating- and cooling-related components of usage.

Data Screening and Model Attrition

Data anomalies, outliers, missing data points, incomplete records, and other data issues all introduce potential bias into a billing analysis. The Evaluation team used several rules to flag and then remove accounts that failed to meet certain conditions:

- ***Must have sufficient pre- and post-installation billing data for analysis.*** All accounts had to contain a minimum of nine months of pre- and post-installation usage data.
- ***Must have a pre- and post-installation change within 70%.*** All accounts showing post-installation usage changes of up to 70% of pre-installation usage were retained in the analysis.
- Must not be an outlier or vacancy. The Evaluation team performed account-level reviews of pre- and post-installation period usage for all individual participants and removed anomalies (such as periods of vacancies) that could bias the savings results. We also removed units that participated in another energy-efficiency program from the analysis, as we could not determine which project created the observed savings.

The data screening resulted in a final analysis sample of three unique participant properties representing 77 tenant units. This corresponds to just under half (43%) of the original participating properties. As shown in Table B-2, the largest source of attrition for the billing analysis of participants originated from removing vacancies from the analysis, primarily because the billing data was only available for accounts that were active at the time of the request. Many of the accounts that were currently active did not have the necessary historical usage data at the apartment unit level to be included in the analysis. For the nonparticipant group, the single largest source of attrition resulted from units that did not show an electric heating signature.

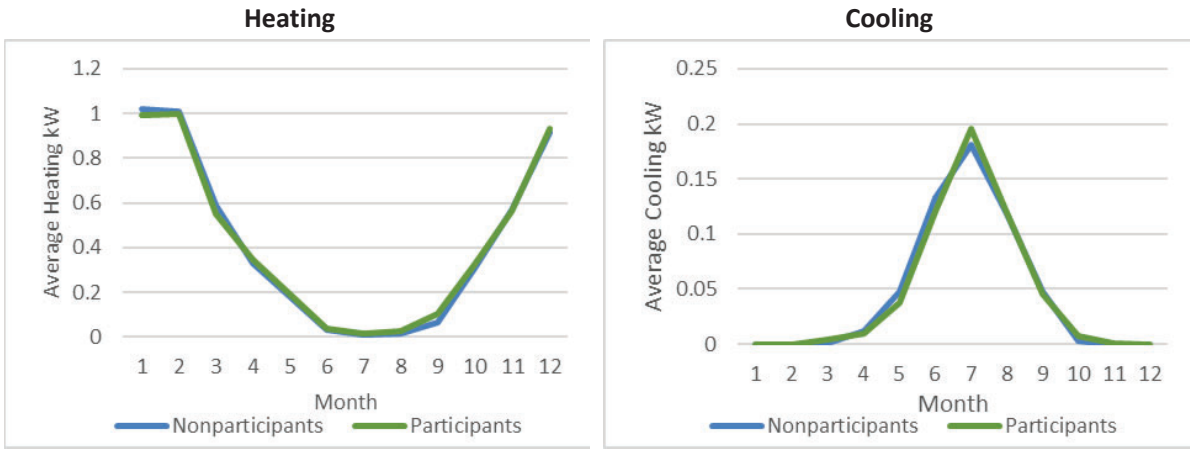
Table B-2. Income Qualified Multifamily Heat Pump Billing Analysis Summary Attrition

Screen	Participants	Nonparticipants
Initial Requested Sample	**97**	**2,329**
AMI Data Available	96	2,308
Sufficient Pre-Post Data	94	2,192
Removed Outliers/Vacancies	84	1,733
Matched Nonparticipant Property Type to Participant Property Type (such as removed high rise and mobile homes)	84	1,583
Determined that Dwelling Used Electric Heating	84	145
Passed Pre-Post Hourly PRISM Models/Hourly Prediction	84	132
Change within 70%	77	119
Matched Usage to Participants	77	112
Final	**77**	**112**

Baseline Electric Energy Use

Baseline multifamily building electric usage—the whole-building electric usage before installing energy-efficiency upgrades—is a critical input to whole-building energy savings estimation for electric-heated properties. The Evaluation team, using hourly PRISM (Princeton Scorekeeping Method) weather normalization and energy load disaggregation models, estimated the annual and monthly heating and cooling loads for the Income Qualified Multifamily participating tenant units. Additionally, estimating baseline heating and cooling energy usage across both participating and nonparticipating tenant units allows for isolating initiative-induced impacts specific to heat pump installation. This is important, as it accounts for non-programmatic influences on energy use, controlling for occupancy changes, behavior changes, changes attributable to COVID-19, and any other non-programmatic changes. A summary of the monthly average heating and cooling loads (in average kilowatts) across the participants and nonparticipant groups is shown in Figure B-1. There is little discernable difference—and, more importantly, no statistically significant difference—between participants' and nonparticipants' monthly heating and cooling loads.

Figure B-1. Baseline (Pre-Installation) Annual Heating and Cooling Load



The Evaluation team, with access to tenant apartment electric usage, estimated an average weather-normalized pre-installation baseline tenant unit usage of 3,860 kWh. Table B-3 shows the breakdown of the heating, cooling, and annual baseline pre-period annual weather-sensitive usage (per tenant apartment). As expected, given that multifamily tenant units in the CCHP were electrically heated, heating electric energy use is the predominant component (approximately 94%) of annual weather-sensitive use in these units.

Table B-3. Participant Tenant Unit Pre-Period Baseline Electric Weather-Normalized Per-Unit Usage

Usage Type	Weather-Sensitive Annual Usage (kWh)	Heating Usage (kWh)	Cooling Usage (kWh)
Billing Analysis	3,860	3,626	234

Source: Evaluation team AMI billing analysis.

Assess Change in Energy Use

As the final step in the analysis, the Evaluation team estimated real world changes to energy use between pre-and-post-installation usage patterns for participants and nonparticipants. Energy savings are the difference between participants' and nonparticipants' energy usage between the pre- and post-installation periods.

Engineering Calibration and Validation

The Evaluation team benchmarked the billing analysis findings relative to values produced from a simplified heat pump engineering model and the initiative-claimed savings (the initiative relied on current MEMD savings estimates). The goal of benchmarking was to help frame the billing analysis findings and understand how close the changes to energy usage tracked with alternative sources. The Evaluation team compiled initiative tracking claimed savings from eTracker and normalized the savings at the tenant apartment unit level by using the total number of installed heat pumps, the claimed savings, and the total number of apartment units. The team relied on the heating load requirement (3,626 kWh), assumed a CCHP COP of 2.75, and entered this data into a simple algorithm expressing continued baseboard heating, CCHP heating, and total heating demand based on several different displacement scenarios (Table B-4).

Table B-4. Cold-Climate Heat Pump Simplified Engineering Estimate

DHP Heating Load Displacement	Baseboard kWh	CCHP with COP of 2.75 (kWh)	Savings (kWh)	Total kWh
100%	-	1,319	2,307	3,626
75%	907	989	1,731	3,626
50%	1,813	659	1,154	3,626
36%	2,319	475	832	3,626

Bill Savings Estimation

To estimate the bill savings attributable to the CCHPs installed in the multifamily tenant units, the Evaluation team estimated the bill savings occurring during the time-differentiated bill periods across the year. According to residential rate data, peak period rates occur in summer months, from May 1 through September 30, during weekdays from 2 p.m. to 7 p.m. The Evaluation team then estimated the savings occurring during the peak and off-peak periods. Table B-5 shows a summary of the seasonal peak and off-peak rates and savings.

Table B-5. Cold-Climate Heat Pump Bill Savings Calculations

Residential Rate	Residential Billing Rate ($)	Income Qualified Multifamily CCHP Savings Occurring During Each Period (kWh)	Bill Savings ($)
Summer Peak	$0.213	6.1	$1.30
Off-Peak	$0.164	889.9	$145.94
Total Bill Savings			**$147.24**

Electric Savings: Engineering Comparison

The Evaluation team developed a simplified engineering estimate to compare how the evaluated electric savings compared with anticipated savings from a CCHP and added the initiative-claimed savings based on MEMD measures. Table B-6 shows a comparison of Income Qualified Multifamily initiative savings from the billing analysis sample, two engineering estimates based on two different displacement scenarios, and the initiative MEMD claimed savings estimate. The billing analysis estimate showed lower realized savings relative to the engineering estimate (assuming 50% of the electric baseboard heating was displaced by the CCHPs) and the MEMD estimate. In order for the engineering estimate to match the billing savings estimate of 832 kWh of heating load savings, the CCHPs would need to displace just over one-third (36%) of the heating load, which therefore assumes that the legacy baseboard heating systems still account for the majority of heating load for the apartments. The continued use of baseboard heat is consistent with feedback from the tenant survey, in which tenants reported continued use of baseboard heat as their primary heating source.

Table B-6. Annual Per–Tenant Unit Cold-Climate Heat Pump Electric Weather-Sensitive Savings Estimates Comparison

Source	Weather-Sensitive Usage (kWh) (A)	Weather-Sensitive Savings (kWh) (B)	Savings versus Weather-Sensitive Usage (%) (B / A)
Billing Analysis	3,860 (Annual)	896	23.2%
Billing Analysis	3,626 (Heating)	832	22.9%
Engineering @ 50% Displacement [a]	3,626 (Heating)	1,154	31.8%
Engineering @ 36% Displacement [a]	3,626 (Heating)	832	22.9%
MEMD/Pilot Claimed Savings [b]	3,860 (Annual)	1,474	38.2%

[a] This is an engineering estimate based on the heating season only and derived from AMI billing analysis.

[b] This represents annual weather-sensitive usage from the AMI billing analysis.

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Appendix C. Consumers Energy Heat Pump Market Rate Customer Survey

Objectives	Research Questions	Question Number
Assess customer awareness and motivations to install heat pumps	Were participants aware of heat pumps prior to participating in the offering? How do customers learn about heat pumps? What are participants' motivations for installing a heat pump? What are important decision factors for installing a heat pump? How much rebate is required to motivate participation?	Section B
Assess participant installation experience	How did participants experience the installation? Are there opportunities to improve the installation experience?	D1–D3
Document participant perceptions of heat pumps, energy or cost savings, comfort levels, and satisfaction	What are participants' experiences with heating/cooling comfort? How satisfied are participants with the heat pumps and the offering? How satisfied are participants with Consumers Energy?	D4–D12, B1, B2
	What non-energy benefits did the offering generate (such as reduced bill impacts, enhanced comfort levels, and improved operational issues)?	D11
Document participant usage behavior and home characteristics	How do respondents manage energy use at the thermostat?	Section C
	What are participants' home characteristics?	Section E

Survey Overview: The Evaluation team administered an online survey to residential customers who received a new heat pump. Then the team sent an email with a link to the survey, followed by reminder emails to encourage households to complete the survey withing the desired timeframe. In addition, the Evaluation team offered participants a $15 Meijer or Amazon.com gift card for completing the survey.

Target Audience: Census of Residential Market Rate pilot participants who installed a new heat pump as part of the Consumers Energy heat pump offering.

Survey Introduction and Purpose

Welcome, thank you for taking a few minutes to provide feedback about your cooling and heating equipment. Your feedback is very important to us and will help us improve rebates and incentives for new products that help customers save energy. This survey should take about 10 minutes. Your responses are confidential and will be used for research purposes only.

Be sure to enter your name and address at the end of the survey to receive your $15 Meijer or Amazon gift card as our thanks.

Click on the Next and Back buttons at the bottom of each page to navigate through the survey.

A. *Screener*

A1. Our records indicate that you received a rebate for a heat pump installed in your home. Is this correct?
1. Yes
2. No **[TERMINATE]**
98. Don't know **[TERMINATE]**

A2. Approximately how long have you lived in your current home?
1. Less than one year
2. One to three years
3. Over three years

A3. **[If A2=1]** Were you living in your current home when the heat pump was installed?
1. Yes
2. No **[TERMINATE]**

TERMINATION MESSAGE: This survey is for Consumers Energy customers who received a rebate for a heat pump through the heat pump rebate program and who were living in the home when the heat pump was installed. Thank you for your interest in participating in this survey.

B. *Current Company Metrics and Awareness*

We'd like to ask some questions about your opinions toward Consumers Energy.

B1. How likely would you be to recommend Consumers Energy to a friend or family member if you had a choice in energy providers?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

B2. Please describe in detail why you gave that rating. _____

With these next questions, we would like to know more about your experience with heat pumps.

B3. Were you familiar with heat pumps before deciding to purchase and install the heat pump?
1. Yes
2. No
98. Don't know

B4. **[DISPLAY IF B3=1]** Prior to participating in this offer, had you ever had a contractor recommend a heat pump?
1. Yes, I had a contractor recommend a heat pump
2. No, a contractor has never recommended a heat pump to me

B5. Before you participated in this offer, were you aware that Consumers Energy offered rebates for heat pumps?

1. Yes, I was aware of heat pump rebates
2. No, I was unaware of heat pump rebates

B6. How did you first learn about the heat pump rebate? Please select only one response. **[RANDOMIZE 1–6]**

1. Contractor recommendation
2. Consumers Energy website
3. Consumers Energy flyer or other marketing material
4. Friend, family, neighbor, or colleague
5. Email from Consumers Energy
6. Online search
7. Other (please specify)

98. Don't know

B7. What were the main reason(s) you decided to install a heat pump in your home? (Select up to three) **[RANDOMIZE 1–9]**

1. To reduce energy bills in the winter months
2. To reduce energy bills in the summer months
3. To distribute heating and cooling more evenly throughout the home
4. To add heating and/or cooling for a new or renovated space in the home
5. To replace a broken heating or cooling system
6. To reduce reliance on natural gas or delivered fuels
7. To add cooling (where there was not previously a whole-home system)
8. To take advantage of heat pump incentives (from Consumers Energy and/or my contractor)
9. To take advantage of electricity produced at my home by renewable sources (such as solar or wind)
10. Something else (please describe)

B8. Please rate the importance of the following items on your decision to install a heat pump. **[RANDOMIZE ITEMS]**

Items	Not at All Important 1	2	3	4	5	6	7	8	9	Extremely Important 10	Don't know
a. The amount of rebate from Consumers Energy (up to $1,000)	○	○	○	○	○	○	○	○	○	○	○
b. Recommendation from a contractor	○	○	○	○	○	○	○	○	○	○	○
c. Possible energy savings over the previous heating/cooling system	○	○	○	○	○	○	○	○	○	○	○

B9. Would you have installed a heat pump if Consumers Energy had not offered a heat pump rebate?
1. Yes (I would have installed a heat pump without a rebate)
2. No
98. Don't know

B10. **[IF B9>1]** Would you have installed a heat pump if the rebate had been one-quarter of the value you received (up to $250)?
1. Yes (I would have installed the heat pump with a $250 rebate)
2. No
98. Don't know

B11. **[IF B9>1]** Would you have installed a heat pump if the rebate had been half as much as the amount you received (up to $500)?
1. Yes (I would have installed the heat pump with a $500 rebate)
2. No
98. Don't know

C. *Thermostat Use*

Next, we have a few questions about how you typically use your thermostat to manage the level of comfort in your home.

C1. What type of thermostat do you have in your home? (Select one.)
1. **Non-programmable** thermostat (set temperature manually and it did not change automatically)
2. **Programmable** thermostat with **set-backs programmed** (thermostat set to automatically change temperature at specific times)
3. **Programmable** thermostat—**not programmed** (thermostat has programming capability, but these were not used.)
4. **Basic networked or Wi-Fi–enabled** thermostat (had remote control, but not occupancy sensing or learning features)
5. **Smart learning** thermostat that includes advanced features such as occupancy sensing and schedule learning (examples include Nest, Ecobee, Honeywell Lyric, and Emerson Sensi)
98. Don't know

C2. Who in your household tends to monitor and adjust your thermostat?
1. I mostly monitor and adjust my home thermostat
2. Everyone in my household monitors and adjusts my home thermostat
3. Other members of my household typically monitor and adjust my home thermostat

C3. How did your household **most frequently** manage your thermostat to control the temperature in your home this summer? (Select one)
1. Keep it at a constant temperature
2. Manually adjust the temperature as needed
3. Create customized/programmed settings to automatically change temperatures at different times of the day
4. Allow the smart thermostat to manage the temperature by learning my preferences and/or detecting when home or away
5. Other (please describe)
98. Don't know

C4. Your heat pump offers the ability to use heating and cooling schedules. Did the installation technician setup your heat pump on a heating and cooling schedule?
1. Yes, the installer set up a heating and cooling schedule
2. No, the installer did not set up a heating and cooling schedule
98. Don't know

C5. **[IF C4=1]** Are you still using this heating and cooling schedule?
1. Yes, I have kept the heating and cooling schedule
2. No, I (or someone in my household) turned off the heating and cooling schedule
3. No, I (or someone in my household) changed the heating and cooling schedule to my own
98. Don't know

C6. Have you been provided with instructions on how to set up and control your heating and cooling schedule on your heat pump?
1. Yes, I received instructions
2. No, I did not receive instructions
98. Don't know

D. *Installation and Usage Experience*

Next, we would like to know about your experience with the heat pump.

D1. Our records indicate that the heat pump was installed in your home around **[INSTALLATION-COMPLETE DATE]**. Were you present during the installation of the heat pump?
1. Yes
2. No

D2. Using a rating scale from 1 to 10, where 1 is *unacceptable* and 10 is *outstanding*, how would you rate each of the following installation experiences with the heat pump offering?

Question	Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know / NA
Scheduling a time for installation	O	O	O	O	O	O	O	O	O	O	O
Staying informed about the installation	O	O	O	O	O	O	O	O	O	O	O
[If D1=1] Overall installation time	O	O	O	O	O	O	O	O	O	O	O
[If D1=1] The professionalism of the installation technician	O	O	O	O	O	O	O	O	O	O	O
Education and instructions provided to you about heat pump usage	O	O	O	O	O	O	O	O	O	O	O
Follow-up from the installation technician or Consumers Energy	O	O	O	O	O	O	O	O	O	O	O

D3. **[IF ANY QUESTION IN D2=6 OR LOWER]** If there was something unsatisfactory about the heat pump installation, please describe in detail why you gave that rating.

_____

D4. In general, how did the heat pump affect your home comfort? (Select all that apply)

1. My home is **just as comfortable** as it was previously
2. My home is **more comfortable** than it usually was
3. My home is uncomfortably warm
4. My home is uncomfortably cold
5. My home is **too humid**
6. My home is **too dry**
7. My home was more evenly heated and/or cooled prior to the installation
8. Something else (please describe)

D5. **[IF D1=1 AND COMPLETE DATE IS PRIOR TO APRIL 1, 2021]** How would you rate the heating comfort level provided by the heat pump during winter months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
O	O	O	O	O	O	O	O	O	O	O

[If D5<6] What concerns do you have about the heat pump's ability to heat to your comfort level?

_____

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D6. How would you rate the cooling comfort level provided by the heat pump during summer months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
O	O	O	O	O	O	O	O	O	O	O

[If D7<6] What concerns do you have about the heat pump's ability to cool to your comfort level?

_____

D7. Taking everything into consideration, how would you rate your overall experience with the heat pump so far?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
O	O	O	O	O	O	O	O	O	O	O

D8. Based on your experiences with the heat pump so far, how likely would you be to recommend it to a friend?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

D9. Based on your experience so far, do you have any recommendations to improve the heat pump rebate offer? _____

98. Don't know

D10. Since the heat pump was installed, have you seen a lower-than-expected energy bill?

1. Yes
2. No
3. Too soon to tell
98. Don't know

D11. In addition to energy savings, if any, are there additional benefits you have experienced or observed from the installation of a heat pump? (Select all that apply) **[RANDOMIZE]**

1. Increased comfort
2. Lower utility bills
3. Improved appearance of my home
4. Improved air quality
5. Improved heating and cooling distribution (across sections of my home)
6. Less maintenance required

7. Improved ability to manage heating/cooling on a schedule
8. Fewer illnesses for household members
9. Other (please specify)
10. Too soon to know **[EXCLUSIVE OF OTHER RESPONSES]**
11. No other benefits **[EXCLUSIVE OF OTHER RESPONSES]**

98. Don't know **[EXCLUSIVE OF OTHER RESPONSES]**

D12. **[If D12=1 AND D11<10]** Considering that the heat pump offering provided both saved energy and some additional benefits to your home, please indicate which was the most important to you:

1. The energy savings
2. The other benefits previously identified
3. The energy savings are equal to the other benefits

98. Don't know

E. *Demographics*

Finally, we have a few questions about your home.

E1. How many people live in your household on a regular basis, year-round?

1. 1
2. 2
3. 3
4. 4
5. 5
6. More than 5

99. Prefer not to answer

E2. Approximately how many square feet of living space does your home have? Do not include the basement unless it is a space that you consider lived in.

1. Under 1,000 square feet
2. 1,000 to less than 1,500 square feet
3. 1,500 to less than 2,000 square feet
4. 2,000 to less than 2,500 square feet
5. 2,500 to less than 3,000 square feet
6. 3,000 to less than 4,000 square feet
7. 4,000 or more square feet

98. Don't know

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F. *Closing*

F1. On occasion, managers of the Consumers Energy programs may want to contact a customer to learn more about their participation experience. Please check here if you prefer not to be contacted by a program manager.
1. Do not contact me

F2. Do you have any recommendations for ways Consumers Energy can support you in helping you save energy?
1. Please describe_____

F3. To thank you for your time spent completing this survey, we would like to send you a $15 gift card to either Meijer or Amazon.com. Please choose which gift card you would like to receive.
1. $15 Meijer gift card
2. $15 Amazon.com gift card
3. Neither – I do not wish to receive a gift card

F4. **[IF F3=1 OR 2]** Please provide your name, address, and email to receive your gift card. This information will only be used to mail your gift card.
1. Name:_____
2. Address:_____
3. Address 2:_____
4. City:_____
5. State:_____
6. Zip:_____
7. Email**:** _____

Please click Next to submit the survey.

[END OF SURVEY MESSAGE] Those are all the questions we have at this time. Thank you for your participation in the Consumers Energy heat pump offer.

For more information on energy efficiency, here's where to find it:

- **Want Online Information about Our Other Energy-Efficiency Rebates and Programs?** For details of additional ways Consumers Energy may be able to help you make your home more energy efficient and help you manage your monthly energy bills, please visit us online at ConsumersEnergy.com/myhome.
- **Want to Speak to an Energy-Efficiency Advisor by Phone?** To talk to someone about additional rebates and programs, please contact one of our Energy Advisors at (888) 652-1237.

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Appendix D. Consumers Energy Heat Pump Property Owner and Manager Interview Guide

Research Questions

Objectives	Research Questions	Interview Section
Document participant installation experience	How well did the offering manage the user installation experience? Are there opportunities to improve the installation experience?	B1, B3
Document participant usage behavior and experience	How are tenants using and operating the heat pumps? Did customers retain secondary or supplemental heating equipment after the heat pump was installed?	B2, B4
Document awareness and perceptions of heat pumps	What is the current perception of heat pump technologies? Were participants aware of heat pumps prior to being approached by Consumers Energy or the contractor? What are the perceived energy benefits of heat pumps? What non-energy benefits did the offering generate (such as reduced bill impacts, enhanced comfort levels, or improved operational issues)?	C1–C4, E2–E5
Document participant decision-making around participating in the heat pump offering	What key factors affected participants' decisions to install a heat pump? What are the key barriers to adopting heat pumps?	D1–D4
Identify marketing and outreach best practices	How did the participant learn about the offering?	C3
	What are the most effective means of marketing heat pumps?	F1–F3
Assess satisfaction with the offering and with Consumers Energy	How satisfied are property owners and managers with the heat pump offering? How satisfied are tenants with the heat pumps and the offering? How satisfied are property owners and managers with Consumers Energy?	G1–G4

Target Audience: The target audience for these interviews was multifamily PMOs who participated in the CCHP initiatives. The Evaluation team attempted to interview a census of participating PMOs.

A. General Introduction

A1. To begin, please tell me about your multifamily properties.

1. How many unique multifamily properties do you own or manage?
2. How many of them are located in Michigan?
3. Do you own/manage only subsidized or income eligible housing or do you also own/manage market rate properties?

B. Installation and Usage Experience

B1. Please describe your experience, including any positive or negative elements, of the heat pump installation for each of the following installation components (please note if you are not aware of any of these elements):

1. Scheduling a time for the installation
2. Informing the tenants
3. Overall installation time
4. Professionalism of the installation technicians
5. Education and instructions provided to management about heat pump usage
6. Education and instructions provided to tenants about heat pump usage **[PROBE: WERE YOU INFORMED ABOUT PRIORITIZING HEAT PUMP USAGE OVER BASEBOARD HEATING?]**
7. Follow up

B2. Have you received any feedback from your tenants about the new heat pumps? **[PROBE: DO THE COMMENTS TEND TO BE POSITIVE, COMPLAINTS, OR QUESTIONS?]**

B3. Have you had any concerns or issues with the heat pumps installed in your property? **[PROBE: HAVE TENANTS COMPLAINED, DO MAINTENANCE STAFF HAVE ANY FEEDBACK ABOUT THEM?]**

B4. It is our understanding that the existing baseboard heating equipment was left in tenant apartments. Are you aware of whether tenants are continuing to use their baseboard heaters or if they rely mostly on the new heat pumps for heating?

1. Are you aware if the tenants received educational materials or training on the use of the heat pumps? **[PROBE: HAVE TENANTS SEEN THESE MATERIALS? HOW WERE THEY DISTRIBUTED? DO THEY FIND THE MATERIALS TO BE USEFUL?]**

C. Heat Pump Awareness and Perceptions

C1. Before participating in this heat pump offering, were you familiar with heat pumps?

C2. Prior to participating in this offering, had you ever had a contractor recommend heat pumps?

C3. Before you participated in this offering, were you aware that Consumers Energy offered rebates for heat pumps?

1. **[IF HEARD ABOUT OFFERING]** Where did you hear about the heat pump offering?
2. **[IF HEARD ABOUT OFFERING]** What were your immediate perceptions of the offering?

C4. Other than **[NAME OF PROPERTY IN THE HEAT PUMP OFFERING]**, do any of your properties currently have heat pumps installed for heating and cooling?

1. **[IF HAS HEAT PUMPS INSTALLED]** How many (if any) of the properties you own/manage use heat pumps? **[PROBE TO SEE IF THEY ARE IN MICHIGAN]**
2. For those properties, do residents typically retain secondary or supplemental heating equipment after the heat pump is installed? Please describe.

D. Motivators and Barriers

D1. What were the most important factors in your decision to participate in the heat pump offering? **[DO NOT READ OR PROMPT; SELECT ANY THAT ARE MENTIONED]**

1. Lower tenant utility costs
2. Lower owner utility costs
3. Improve the property appearance
4. Improve tenant comfort
5. Increase the property value
6. Replace old or broken equipment
7. Take advantage of low-cost/no-cost improvements
8. Reduce impact on the environment
9. Lower operating and maintenance costs
10. Improve property aesthetics
11. Improve health and safety
12. Satisfaction with previous Consumers Energy program experience
13. Turnkey and easy to participate
14. Other (Please specify)

98. Don't know

D2. Which of these factors was the most important to your decision? **[REPEAT THOSE MENTIONED IN PREVIOUS QUESTION TO ALLOW SELECTION FROM LIST]**

D3. What do you consider to be the primary barriers to adding heat pumps to other properties? **[DO NOT READ OR PROMPT; SELECT ANY THAT ARE MENTIONED]**

1. Overall upfront costs
2. Logistical effort required to deal with installation
3. Finding the right contractor
4. Getting management approval
5. Tenant disruption
6. Tenants' ability to use the equipment to reduce energy consumption
7. Other (Please specify)

98. Don't know

D4. Which of these factors is the most significant barrier to your decision? **[REPEAT THOSE MENTIONED IN PREVIOUS QUESTION TO ALLOW SELECTION FROM LIST]**

E. Savings and Benefits of Participation

E1. Do you or your tenants pay the electric utility bills?

E2. **[IF TENANTS PAY]** Have your tenants provided feedback about their bills since installation of the heat pumps? If so, please describe what this feedback has entailed.

E3. **[IF PROPERTY OWNER/MANAGER PAYS UTILITY BILLS]** Have you noticed any change in your utility bills since installation of the heat pumps? If so, please describe the change. **[PROBE: HAVE THERE BEEN ANY DIFFERENCES IN UTILITY BILL CHANGES BETWEEN WINTER HEATING AND SUMMER COOLING?]**

E4. In addition to energy savings, are there any other benefits that your property, your tenants, or property management have experienced from installing the heat pumps? **[DO NOT READ OR PROMPT; SELECT ANY THAT ARE MENTIONED]**

1. Lower maintenance costs
2. Improved operations
3. Increased property value
4. Decreased vacancy rates
5. Increased rental income
6. Increased net operating income
7. Increased tenant comfort
8. Decreased late or nonpayment of rent
9. Decreased tenant complaints
10. Improved property aesthetics
11. Health and safety improvements
12. Other (Please specify)
13. Too soon to tell
14. No other benefits

98. Don't know

E5. **[ASK IF E3=YES AND E4≠13, 14, OR 98]** Considering that the heat pump offering provided both energy savings and some other benefits to your property, please indicate which was the <u>most important</u> benefit:

1. The energy savings
2. The non-energy benefits (previously identified)
3. The energy savings benefits are equal to the non-energy benefits

98. Don't know

F. Outreach and Marketing

F1. What, in your opinion, could be done to increase the adoption of heat pumps in the multifamily market?

F2. What are the most effective ways to let other multifamily property owners and managers know about the benefits of heat pumps?

F3. What information would be helpful for other property managers and owners to become interested in heat pumps?

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G. Opinion of Heat Pump Offering and Consumers Energy

G1. Taking everything into consideration, how would you rate your overall experience with the multifamily heat pump offering, where 1 means *unacceptable* and 10 means *outstanding*?

Unacceptable 1	2	3	4	Average 5	6	7	8	9	Outstanding 10	Don't know
O	O	O	O	O	O	O	O	O	O	O

G2. Based on your experiences with the heat pump offering, how likely would you be to recommend the offering to a business colleague, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

G3. Based on your experiences with the heat pump offering, how likely would you be to recommend Consumers Energy to a business colleague if you had a choice in energy providers, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

G4. Based on your experience with the heat pump offering, how likely would you be to make similar improvements to some or all the properties you manage, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

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H. Wrap Up

H1. In what ways can Consumers Energy programs better help you manage your multifamily properties' energy use?

H2. Our research also includes a tenant survey to capture their experience and usage with the heat pumps, but we do not have tenant contact information to recruit them for this effort. Would you be interested in **[OPTION A]** securely sharing tenant emails with us so they can receive an email link to complete an online survey or **[OPTION B]** would you be willing to forward an email invitation to your tenants to complete the online survey? Tenants will receive a $15 gift card for their time. [**ENTER WILLINGNESS RESPONSE OPTION AND BE SURE TO REQUEST THE PMO EMAIL ADDRESS TO ENSURE EITHER OPTION CAN BE SHARED**]

Those are all the questions we have. Thank you very much for taking the time to assist us with this evaluation. Your contribution is a very important part of the process. We are planning to send you your choice of a $50 Amazon or Meijer card (if you choose Meijer, we will need your mailing address, as there is no e-card option). Please let us know your choice of card **[ENTER CARD CHOICE AND REQUEST EMAIL ADDRESS IF AMAZON OR MAILING ADDRESS IF MEIJER]**.

Look for your gift card in the mail in the next three weeks. If you have any questions about this survey or about your gift card, please call **[APEX STAFF]** at **[303-590-9888 Ext XXX]**. Thank you for your time.

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Appendix E. Consumers Energy Heat Pump Multifamily Tenant Survey Guide

Objectives	Research Questions	Question Number
Document participant awareness of heat pump	Are tenants aware of what a heat pump is? Were tenants aware of a heat pump installed for their apartment? Are tenants who were aware of the heat pump also aware that Consumers Energy funded it?	Section B
Document participant installation experience	How did the heat pump offering help Consumers Energy to manage the tenant installation experience? Are there opportunities to improve the installation experience?	D1–C3
Assess participant perceptions of heat pump impact on comfort levels and electricity bills	What perceptions do tenants have of heating and cooling comfort levels? What are the perceived energy benefits of heat pumps? What non-energy benefits did the offering generate (such as reduced bill impacts, enhanced comfort levels, and improved operational issues)?	C4–C11, D2–D4
Document participant usage behavior and experience	How are tenants using and operating the heat pumps? Are tenants continuing to use their baseboard heating?	C12–C18
Assess participant satisfaction with the offering and with Consumers Energy	How satisfied are tenants with the heat pumps offering? How satisfied are tenants with Consumers Energy?	E1–G3, A1, A2

Survey Overview: The Evaluation team administered a web-based survey with multifamily tenants who received a new heat pump. Then the team sent an email with a link to the survey to participants who could be matched to participating multifamily buildings and had an email address, followed by reminder emails to encourage households to complete the survey within the desired timeframe. In addition, the Evaluation team offered participants a $15 Meijer or Amazon.com gift card for completing the survey.

Target Audience: Census of individual tenant dwellings that could be matched to the multifamily building and had an email address. The Evaluation team had 75 emails associated with the multifamily properties by linking an income-qualified survey contact database with the Income Qualified Multifamily incentive properties. Assuming a 10% response rate, we hoped to receive approximately eight completed surveys.

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A. Current Company Metrics

First, we'd like to ask some questions about your opinions toward Consumers Energy.

Consumers Energy Count on Us®

A1. How likely would you be to recommend Consumers Energy to a friend or family member if you had a choice in energy providers?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

A2. Please describe in detail why you gave that rating. _____

B. Awareness

B1. Are you familiar with what a heat pump is?

1. Yes, I am familiar
2. No, I do not know what a heat pump is

[IF B1=2, PROVIDE EXPLANATION ABOUT HEAT PUMPS: HEAT PUMPS ARE EQUIPMENT THAT PROVIDES BOTH HEATING AND COOLING FOR HOMES.]

B2. Our records indicate that the apartment you currently occupy received a new heat pump. Are you aware of this?

1. Yes
2. No

B3. **[If B2=1]** Were you aware that Consumers Energy funded this project and made the heat pump technology available in your home?

1. Yes, I was aware of Consumers Energy involvement
2. No, I was unaware of Consumers Energy involvement

98. Don't know

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C. Installation and Usage Experience

Next, we would like to know about your experience with the heat pump.

[SHOW QUESTIONS D1 TO C3 IF COMPLETE DATE IS NOT EMPTY]

C1. Our records indicate that the heat pump was installed in your apartment around **[COMPLETE DATE]**. Were you present during the installation of the heat pump?

1. Yes, I was present during installation
2. No, I was not present during installation

C2. Using a rating scale from 1 to 10, where 1 is *unacceptable* and 10 is *outstanding*, how would you rate each of the following installation experiences with the heat pump offering?

Question	Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
Scheduling a time for installation	O	O	O	O	O	O	O	O	O	O	O
Staying informed about the installation	O	O	O	O	O	O	O	O	O	O	O
[IF C1=1] Overall installation time	O	O	O	O	O	O	O	O	O	O	O
[IF C1=1] The professionalism of the installation technician	O	O	O	O	O	O	O	O	O	O	O
Education and instructions provided about heat pump usage	O	O	O	O	O	O	O	O	O	O	O
Follow-up from the installation technician or Consumers Energy	O	O	O	O	O	O	O	O	O	O	O

C3. **[IF ANY QUESTION IN C2≥6]** If there was something unsatisfactory about the heat pump installation, please describe in detail why you gave that rating.

_____

C4. Approximately how long have you lived in your current apartment?

1. Less than six months
2. Between six months and one year
3. Over one year

C5. Were you living in your apartment last winter, before the heat pump was installed?

1. Yes
2. No

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C6. **[IF C5=1]** How would you rate the heating comfort level provided by the heat pump during winter months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

C7. **[IF C6<7]** What concerns do you have about the heat pump's ability to heat to your comfort level? _____

C8. Were you living in your apartment last summer, before the heat pump was installed?

1. Yes
2. No

C9. **[IF C8=1]** How would you rate the cooling comfort level provided by the heat pump during summer months?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

C10. **[IF C9<7]** What concerns do you have about the heat pump's ability to cool to your comfort level? _____

C11. In general, how did the heat pump affect your home comfort? (Select all that apply)

1. My home is **just as comfortable** as it was previously
2. My home is **more comfortable** than it usually was
3. My home is uncomfortably warm
4. My home is uncomfortably cold
5. My home is **too humid**
6. My home is **too dry**
7. My home was more evenly heated and/or cooled prior to the installation
8. Something else (please describe)

C12. Our records indicate that the existing baseboard heating equipment was left in all apartments where heat pumps were installed.
Which of the following best describes how you heated your apartment last winter?
[RANDOMIZE 1-3]

1. Mostly used baseboard heating
2. Relied evenly on the heat pump and baseboard heating
3. Mostly used the new heat pump

98. Don't know

C13. Your baseboard heating should have a thermostat that controls your home's heating.
What type of thermostat do you have in your home?

1. **Non-programmable** thermostat (set temperature manually and it did not change automatically)
2. **Programmable** thermostat with **set-backs programmed** (thermostat set to automatically change temperature at specific times)
3. **Programmable** thermostat—**not programmed** (thermostat has programming capability, but these were not used.)
4. **Basic networked or Wi-Fi–enabled** thermostat (had remote control, but not occupancy sensing or learning features)
5. **Smart learning** thermostat that includes advanced features such as occupancy sensing and schedule learning (examples include Nest, Ecobee, Honeywell Lyric, and Emerson Sensi)

98. Don't know

C14. Who in your household tends to monitor and adjust your thermostat associated with your baseboard heating?

1. I mostly monitor and adjust my home baseboard thermostat
2. Everyone in my household monitors and adjusts my home baseboard thermostat
3. Members of my household (other than me) typically monitor and adjust my home baseboard thermostat

C15. How did your household **most frequently** manage your baseboard thermostat to control the temperature in your home this summer?
1. Keep it at a constant temperature
2. Manually adjust the temperature as needed
3. Create customized/programmed settings to automatically change temperatures at different times of the day
4. Allow the smart thermostat to manage the temperature by learning my preferences and/or detecting when home or away
5. Other (please describe)
98. Don't know

C16. Your heat pump offers the ability to use heating and cooling schedules. Did the installation technician set up your heat pump on a heating and cooling schedule?
1. Yes, the installer set up a heating and cooling schedule
2. No, the installer did not set up a heating and cooling schedule
98. Don't know

C17. **[IF C16=1]** Are you still using this heating and cooling schedule?
1. Yes, I have kept the heating and cooling schedule
2. No, I (or someone in my household) turned off the heating and cooling schedule
3. No, I (or someone in my household) changed the heating and cooling schedule to my own
98. Don't know

C18. Have you been provided with instructions on how to set up and control your heating and cooling schedule on your heat pump?
1. Yes, I received instructions
2. No, I did not receive instructions
98. Don't know

D. Savings and Benefits of Participation

D1. How would you describe how your electric utility use is billed?
1. I receive a monthly electric utility bill directly from the utility for my usage
2. My landlord receives an electric utility bill for the whole building's usage
3. The electricity use for my unit is billed some other way (please describe)
4. I'm not sure how the electric utility use is billed

D2. **[IF E1=1]** Have you seen a lower-than-expected energy bill?
1. Yes
2. No
3. Too soon to tell
98. Don't know

D3. In addition to energy savings, if any, are there other benefits that you have experienced or observed from the installation of heat pumps? (Select all that apply) **[RANDOMIZE 1–8]**

1. Increased comfort
2. Lower utility bills
3. Decreased complaints about my apartment temperature
4. Improved air quality
5. Improved appearance of my apartment
6. Improved heating and cooling distribution (across sections of my home)
7. Fewer illnesses for household members
8. Improved ability to manage heating/cooling on a schedule
9. Other (Please specify)
10. Too soon to tell [EXCLUSIVE OF OTHER RESPONSES]
11. No other benefits [EXCLUSIVE OF OTHER RESPONSES]

98. Don't know [EXCLUSIVE OF OTHER RESPONSES]

D4. **[ASK IF D2=1 AND D10≠10, 11, OR 98]** Considering that the heat pump offering provided both saved energy and some additional benefits to your apartment, please indicate which was most important to you:

1. The energy savings
2. The other benefits previously identified
3. The energy savings are equal to the other benefits

98. Don't know

E. Opinion of Heat Pump Offering and Consumers Energy

E1. Taking everything into consideration, how would you rate your overall experience with the heat pump?

Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know
○	○	○	○	○	○	○	○	○	○	○

E2. Based on your experiences with the heat pump, how likely would you be to recommend a heat pump to a friend?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already Did Recommend	Don't know
○	○	○	○	○	○	○	○	○	○	○	○

E3. Do you have any recommendations for ways Consumers Energy can further support you in saving energy?
1. Please describe_____

F. Closing

F1. On occasion, managers of the Consumers Energy programs may want to contact a customer to learn more about their participation experience. **Please check here if you prefer not to be contacted by a program manager.**
1. Do not contact me

F2. To thank you for your time spent completing this survey, we would like to send you a $15 gift card to either Meijer or Amazon.com. Please choose which gift card you would like to receive.
1. $15 Meijer gift card
2. $15 Amazon.com gift card
3. Neither – I do not wish to receive a gift card

F3. **[ASK IF F2=1 OR 2]** Please provide your name, address, and email to receive your gift card. This information will only be used to mail your gift card.
1. Name:_____
2. Address:_____
3. Address 2:_____
4. City:_____
5. State:_____
6. Zip:_____
7. Email**:** _____

Please click Next to submit the survey.

Those are all the questions we have at this time. Thank you for your participation in the Consumers Energy heat pump offer.

For more information on energy efficiency, here's where to find it:

- **Want Online Information about Our Other Energy-Efficiency Rebates and Programs?** For details of additional ways Consumers Energy may be able to help you make your home more energy efficient and help you manage your monthly energy bills, please visit us online at ConsumersEnergy.com/myhome.
- **Want to Speak to an Energy-Efficiency Advisor by Phone?** To talk to someone about additional rebates and programs, please contact one of our Energy Advisors at (888) 652-1237.

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Appendix F. Consumers Energy Heat Pump Commercial Interview Guide

Cold-Climate Heat Pump Participant Interview Research Objectives and Questions

Objectives	Research Questions	Interview Questions
Explore key factors in customer decision-making regarding heat pump installations	Were customers aware of heat pumps prior to the pilot outreach?	C1, C1a, C1b, C1c
	What were customers' perceptions of heat pumps prior to installation? What barriers did customers face when considering the installation of heat pumps?	C3
	What motivated customers to install heat pumps?	C5, C5a, C5b
	What technology would customers have installed without the initiative intervention and why?	C4, C4a
Explore customer experiences during the heat pump installation process	How did participants find their contractor who installed the equipment? How did participants perceive their contractors knowledge of heat pump technology and installation methods? How did participants perceive the length of time to purchase and install the heat pump and how long did that process take?	D1, D2, D4, D4a, D5
	What type of equipment did customers use prior to the heat pump? Did participants need to install new duct work, a new thermostat, and/or back-up systems for their heat pump?	D6, D7, D8, D9, D10
	Were participants satisfied with their contractors (including their interactions with their contractors and the contractors' performance), the installation process, and the timeline? Why or why not? Would they use the contractor again?	G1a, G1b, G1d, D3
Explore customer experiences using their heat pump	Does the heat pump provide the level of heating required for comfort and meeting customer needs?	E2, E2a
	Does the heat pump provide the level of cooling required for comfort and meeting customer needs?	E3, E3a
	Can customers operate the heat pump easily, including the remote controls? Do they need to change their habits in any way?	E1, E4, E4a, E5, E5a, E5b, E6
	How does the heat pump compare to prior equipment with regards to air quality?	E7, E7a
	How does the heat pump compare to prior equipment with regard to noise?	E8, E8a
	Are participants satisfied with their heat pump? Why or why not?	G1c
Explore customer experiences with the initiative offering	How did participants learn of the initiative opportunity?	C2
	Did participants interact with program staff? If so, what were their experiences?	F1, F1a, F1b
	Were participants satisfied with the pilot offering?	G1e
Identify opportunities to best support heat pump technology moving forward	Which aspects of the initiative offering were most helpful to customers (such as the staff support versus the financial incentive)?	F4
	What additional support, if any, did participants need to pursue the installation and use of their heat pump?	F2, F2a, F3, F3a, D4b

Survey Overview. The Evaluation team attempted to interview the full population of participating customers, with a goal to complete at least five interviews. The team included a $75 incentive to increase the likelihood of response. The Evaluation team sent advance emails to all respondents with available email addresses and followed up with phone calls as needed to schedule interviews. This email explained the research and provided a Consumers Energy and Evaluation team contact person if the respondent had additional questions or wanted to schedule an interview. For phone recruitment, the

team left a voicemail or receptionist message on the first attempt whenever possible, then used discretion to determine any additional messages left on subsequent attempts (with a maximum of five attempts to each contact).

A. Introduction

A1. First, can you tell about the work you do at **[BUSINESS NAME]**?

A2. And what is your role at the business? **[PROBE FOR ROLE AND RESPONSIBILITIES]**

B. Consumers Energy

Next, we'd like to ask you a few questions about your opinions toward Consumers Energy.

B1. How likely is it that you would recommend Consumers Energy to a friend or colleague if you had a choice in energy providers using a scale from 1 to 10, where 1 means *extremely unlikely* and 10 means *extremely likely*?

Extremely unlikely 1	2	3	4	5	6	7	8	9	Extremely likely 10	Already did recommend	Don't know
O	O	O	O	O	O	O	O	O	O	O	O

B2. Please describe why you gave that rating.

B3. To what extent do you agree that Consumers Energy made it easy to participate in the Cold-Climate Heat Pump Initiatives, using a scale from 1 to 5, where 1 means *strongly disagree* and 5 means *strongly agree*?

Strongly disagree 1	2	3	4	Strongly agree 5
O	O	O	O	O

C. Decision-Making

Next, I'd like to ask some questions about your decision to install a heat pump.

C1. Prior to Consumers Energy contacting you about the heat pump offering, how familiar were you with heat pump technology to heat and cool your facility?

1. **[IF AWARE, PROBE]** What were your perceptions of heat pumps?
2. **[IF AWARE, PROBE]** Had you heard anything about their performance in colder climates?
3. **[IF KNOW ABOUT HEAT PUMP PERFORMANCE IN COLD CLIMATES]** Where did you hear about it?
4. **[IF AWARE, PROBE]** Had you heard anything about their performance in colder climates?

C2. How did you first learn of the opportunity to receive a heat pump through Consumers Energy?

C3. What key concerns or considerations did you have when deciding whether or not to install the heat pump?

C4. What motivated you to agree to install the heat pump?
1. Were there any other factors? **[PROBE FOR COST, ENERGY SAVINGS, ENERGY-EFFICIENCY, REBATE FROM CONSUMERS ENERGY]**

C5. Did you have plans to install new heating or cooling equipment if Consumers Energy hadn't reached out to you?
1. **[IF WOULD HAVE INSTALLED NEW HVAC EQUIPMENT]** When would you have installed this new equipment?
2. What steps would you have taken to decide what equipment to purchase?

D. Experience with Contractor Selection and Installation Process

The next set of questions are about your experiences finding a contractor and installing of your new heat pump.

D1. So, once you decided to participate in Consumers Energy's Cold-Climate Heat Pump offering, can you talk me through the steps you took to find and select a contractor to perform the work?

D2. Did you have any difficulties finding a contractor to perform the work?

D3. How knowledgeable were the contractors you worked with about heat pumps? What about the installation process? **[PROBE IF ANY DID NOT SEEM TO BE KNOWLEDGEABLE ABOUT THE EQUIPMENT, WHERE THEY WERE LACKING KNOWLEDGE]**

D4. Once you found a contractor, how long did the project take from start to finish (purchasing to installing)? Did this timeline meet your expectations?
1. **[IF TIME EXPECTATIONS NOT MET]** What were your expectations?
2. **[IF TIME EXPECTATIONS NOT MET]** Is there anything that could have been done differently? **[PROBE IF ANY PART OF THE PROCESS TOOK LONGER THAN EXPECTED]**

D5. If you had to do it over again, would you work with the same contractor?

D6. Prior to the installation, what type of heating equipment did you use? Did you use electric or natural gas or another type of fuel to heat the property?

D7. What type of cooling equipment did you use?

D8. Did your contractor need to install new duct work, a new thermostat, or other infrastructure as part of the heat pump installation?

D9. What did your contractor do with the old heating system? **[PROBE IF REMOVED, KEPT IN PLACE AS BACKUP, CAPPED]**

D10. Did you need to install a new back-up system along with the heat pump? **[PROBE FOR HEATING OR COOLING SYSTEMS]**

E. Experience Using the Heat Pump

Next, I'd like to ask some questions about your experiences using the heat pump itself.

E1. What have been your experiences with operating the equipment to date?

E2. Have you had a chance to use the heating function on the heat pump that was installed at your facility?
   1. **[IF USED HEATING]** What time of year did you use the heating function? Did you have any issues with the heat pump providing sufficient heat for your comfort and meeting your needs? **[PROBE FOR IF THEY EVER HAD ISSUES PROVIDING HEAT]**

E3. Have you used the cooling function?
   1. **[IF USED COOLING]** Did you have any issues with the heat pump providing sufficient cooling for comfort and meeting your needs?

E4. Does the heat pump require any new operating procedures that you needed to learn how to use?
   1. How did that go?

E5. Does the equipment rely on a remote control or app?
   1. Do you use that feature?
   2. How has that gone?

E6. Have you had to change your heating/cooling habits in any way to accommodate the new technology?

E7. Have you noticed any changes in air quality since the heat pump was installed? **[PROBE: DECREASED AIR PARTICLES, NOXIOUS GASES, DEBRIS]**
   1. **[IF YES]** How so?

E8. How does the sound of the new equipment compare to your old heating/cooling equipment?
   1. **[IF SOUND WORSE]** What have you done to deal with the noise, if anything?

F. Experience with Pilot Offering

Next, I have a few questions about your experiences with Consumers Energy in relation to this pilot and then we'll be almost done.

F1. Did you interact with Consumers Energy program staff at any point in the process?
   1. **[IF YES]** What did you discuss?
   2. Did you get your questions answered?

F2. What additional support, if any, did you need *when considering to purchase and install* your heat pump?
   1. Who did you talk to? What questions did you have?

F3. Did you require any additional support—other than what you received from Consumers Energy—during the *installation process*?
   1. What about when using the equipment?

F4. Thinking about all the aspects of the initiative, from the support you received in picking equipment or a contractor to the financial rebate for the project, what aspect was most helpful in your decision to pursue the heat pump installation?

G. Satisfaction

I'd like to wrap up the conversation by asking you to rate your satisfaction on a few different factors.

G1. Feel free to expand on any answers you provide. Each of these items will be on a 1 to 10 scale, where 1 means *unacceptable* and 10 means *outstanding*.

Question	Unacceptable 1	2	3	4	5	6	7	8	9	Outstanding 10	Don't know / NA
The installation your contractor performed	O	O	O	O	O	O	O	O	O	O	O
The time it took to receive and install your equipment	O	O	O	O	O	O	O	O	O	O	O
The performance of the heat pump equipment	O	O	O	O	O	O	O	O	O	O	O
The interactions you had with your contractor	O	O	O	O	O	O	O	O	O	O	O
The overall Consumers Energy offering	O	O	O	O	O	O	O	O	O	O	O

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H. Closing

As we wrap up, I want to provide an opportunity for you to share anything I might have missed with my questions.

H1. Do you have any other comments or information you think might be useful for me to know given what we have talked about today?

H2. These are all the questions I have for you today. It is likely that one of our colleagues will be following up with you in a few months to better understand the energy use of your new cold-climate heat pumps during the winter months, so look out for that email or call. As a thank you for your input, we'd like to send you a $75 gift card redeemable at many businesses, including Amazon, Target, and Kroger. This gift card is called a Tango card and would be sent to your email address within the next five to 10 business days. Alternatively, we can donate the $75 to your local United Way. Which would you prefer?

H3. **[IF TANGO]** Could you please provide your preferred email address to receive the Tango virtual gift card? **[REPEAT BACK EMAIL ADDRESS]**
You should expect to receive your virtual gift card within the next five to 10 business days. The gift card will be emailed directly from **Tango,** with a reference to "Thank you for your participation!" If you have any questions, or have not received your gift card by then, please contact me at **[contact information]**.

H4. [IF UNITED WAY] In whose name should we make the donation to United Way? [INCLUDE FIRST AND LAST NAMES, COMPANY NAME, OR ANONYMOUS]
And what zip code should we use to find your local United Way?

On behalf of Consumers Energy, I want to thank you for taking time to provide input, and have a great day. **[END CALL]**

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Appendix G. Consumers Energy Heat Pump Contractor Interview Guide

Introduction and Purpose

Thank you for taking the time to talk with us today. This interview is a discussion about air source cold climate heat pumps, your businesses experience with the technology, and to assess the current status of the technology in the market. The intended outcome of this discussion is to document the perception, concerns, opportunities, critical decision points, and key outcomes involved with heat pump sales and installations. Consumers Energy can use this documentation to guide future decision making around their energy efficiency programs. We are offering a $75 gift card that can be redeemed at your choice of Amazon or Meijer for those that complete the 30-45 minute interview. We have four main objectives for this interview:

- Identify current levels of awareness and perceptions of heat pump technologies.
- Identify the main barriers to installing heat pumps in Michigan and if the Michigan market is ready for widespread adoption of heat pump technology.
- Identify any marketing or outreach best practices
- Document awareness of available heat pump incentive offerings

We expect this interview to take around 30 minutes.

A. General Introduction

A1. To begin, tell me about your business.
   1. What types of customers do you typically serve? [Standard residential? Income qualified? Multi-family? Commercial? Something else?]
   2. How many projects do you typically complete in a given year?
   3. How many employees does your company have?

A2. What type of equipment do you typically install? [Furnaces? Boilers? Heat pumps? Something else?]

A3. Do you have any experience participating in utility energy efficiency programs?
   1. Which utilities? Which programs? How often?

B. Heat Pump Awareness and Perceptions

B1. Does your company sell and install heat pumps?

1. **[If installs heat pumps]** How many (if any) heat pump sales or installations have you/your company had in the past year (2020)?
2. For those installations, do residents typically retain secondary or supplemental heating equipment after the heat pump is installed? Please describe.
3. What heat pump brands do you carry and install?
   Have you received any manufacturer-specific certifications for installing those brands?
4. How does the average warranty of a CCHP compare to gas furnaces or boilers?
5. **[If does not install heat pumps]** Why don't you install heat pumps?

B2. Do you promote CCHPs to your customers?

1. Are there specific applications or customer types that make good candidates for heat pumps? (i.e. retrofit vs. new construction)
2. Which ones?
3. Why?
4. Are small businesses good candidates for heat pumps?
   Are the barriers to entry different than the residential homeowner?

B3. Generally, what are your perceptions of CCHPs?

1. Do you think that CCHPs are a viable option for widespread adoption in Michigan?
2. Do you think that CCHPs are capable of generating energy savings for end users?
3. What has led to those perceptions of the equipment?
4. What do you think is the value proposition for you to want to install heat pumps? Why would you not want to?
5. Do you know other contractors who install CCHPs? What are their perceptions of the technology?

B4. What are customer perceptions of heat pumps?

1. Do they typically have any awareness of the technology?
2. What do you think is the value proposition for customers to install a heat pump? What are their motivations? If needed: Why would they not want to?
3. Do customers ever request to have the equipment installed without being prompted by your company? How do you respond to that request?
4. Is customer interest in heat pumps increasing, decreasing, or staying about the same? What would you say is causing that change?

B5. To what extent does a negative experience with older heat pump technologies affect your opinion about heat pumps? What about customers experiences?

C. Market Barriers and Regulatory Readiness

C1. **[If installs heat pumps]** How do procedures for a heat pump installation compare to installing other HVAC equipment in terms of:
1. Time required (actual installation time).
2. Sales process/discussions with customers.
3. Revenue/Profit Margin.
4. Equipment availability.
5. What factors can cause variations in these procedures? (e.g. conversion vs. replacing similar equipment).

C2. What would you say are the main barriers or challenges preventing more widespread heat pump adoption in Michigan? [Probe for: customer awareness, contractor perceptions, equipment availability, codes and standards, energy prices, finding good candidates, etc.]

C3. If demand for heat pumps increases, how well do you think the supply chain is prepared to meet that demand (increasing production) for cold climate heat pumps? Why?
1. Do you have any concerns about the availability or delivery timing of heat pump equipment for current or future projects? Why or why not?

D. Outreach and Marketing

D1. What can Consumers Energy do to help drive adoption of heat pumps in the market?

D2. Do you think that messaging is needed to educate people that CCHPs, or heat pumps in general, have improved?
1. **[IF YES]** What would effective messaging look like?

D3. **[If Promotes heat pumps]** When you have a good candidate for a heat pump, what information is most convincing for the customer to install a heat pump?

E. Wrap Up

E1. Before we wrap up, is there anything else you'd like us to know?

Those are all the questions we have for you. Thank you very much for taking the time to assist us with this evaluation. Your contribution is a very important part of the process. Do you mind if we follow-up with you by phone or e-mail later, if additional questions arise?

E2. To thank you for your time spent completing this survey, we would like to send you a $75 gift card to either Meijer or Amazon.com. Please choose which gift card you would like to receive.
1. $75 Meijer gift card
2. $75 Amazon.com gift card
3. Neither – I do not wish to receive a gift card

E3. Please provide your name, address, and email to receive your gift card. This information will only be used to mail your gift card.

1. Name:_____
2. Address:_____
3. Address 2:_____
4. City:_____
5. State:_____
6. Zip:_____
7. Email**:** _____

You should receive your gift card within four weeks. If you have not received it by then, please contact (contact person at Cadmus).

CADMUS

Appendix H. Consumers Energy Heat Pump Manufacturer and Distributor Interview Guide

Research Objectives and Questions

Research Objectives	Research Questions	Interview Questions
Confirm/document the supply chain for CCHPs in Michigan	Do CCHPs follow the typical supply chain structure (Manufacturer -> Distributor -> Contractor -> Customer)?	EE1, EE2
	Does the supply chain vary for small commercial, multifamily, and residential end uses?	EE1
Identify the barriers leading to extended timelines for CCHP installation	How long does it typically take from manufacturing to distribution? Distribution to contractors?	FF1
	What caused delays in the timeline in 2020? Have there been any changes to this timeline due to COVID-19? Were delays different across states? Did demand for CCHP in Michigan differ in 2020 compared to 2019?	FF1, FF2, GG2
	Are any delays expected to improve in 2021?	FF1
Identify sources of differences in CCHP installation costs across states	Are wholesale costs in Michigan comparable to other states?	FF3
	What factors drive pricing of CCHPs?	FF3
Explore the cause of low participation by trade allies	What have manufacturers and distributors done to promote heat pump technology?	GG5, GG6
	What feedback have contractors (distributors) offered to distributors (manufacturers) on perceptions of CCHP?	GG3, GG4
Identify any additional barriers and challenges delaying widespread adoption of CCHPs in Michigan, like training or education	What are the primary barriers or challenges faced by manufacturers / distributors in selling and distributing CCHP?	GG1, G1
Identify ways in which Consumers Energy can influence market adoption	How can utilities best support the adoption of CCHPs? Where is the correct place to offer an incentive (downstream, midstream, or upstream)?	II1
	Are there successful market influences in other states that could be promoted in Michigan?	HH1
	Are there technology advancements that Consumers Energy should be aware of?	HH2

A. Firmographics

First, I have just a couple questions about your organization and your role. Please note that I will keep your individual responses anonymous.

A1. What is your role in the company?

A2. What areas of the country does your company primarily serve?

A3. **[DISTRIBUTORS]** Do you serve as a distributor of heat pumps in states other than Michigan? **[PROBE FOR DETAIL]**

A4. **[MANUFACTURERS]** Do you work with particular states/regions or nationwide? **[PROBE FOR DETAIL]**

B. Supply Chain

Now I have some questions about the supply chain for the cold-climate air-source heat pump market. If possible, I would like you to focus your responses on the market in the state of Michigan.

B1. How does heat pump equipment typically get from the manufacturer to the end-use customer?
1. What are the key roles in the cold-climate heat pump market from production to installation (such as manufacturers, distributors, contractors, and electricians)?
2. Does the supply chain for cold-climate heat pumps differ from traditional air-source heat pumps? What about other types of mechanical equipment (such as furnaces, boilers, or water heaters)? If so, how?
3. Does the supply chain vary depending on the type of building where the unit will be installed (single family, multifamily, or small commercial building)?

B2. Are there particular distributors, manufacturers, or contractors you work with for cold-climate heat pumps in Michigan? **[PROBE FOR DETAIL]**

C. Timeline/Costs

Next, we would like to ask you some questions specifically surrounding production and distribution timelines and costs.

C1. On average, what would you say is the length of time it normally takes for a cold-climate heat pump to reach the distributor or contractor after an order is placed?
Does the timeframe in Michigan differ from other states?
1. **[MANUFACTURERS]** When fulfilling orders for cold-climate heat pumps, what specific manufacturing challenges, if any, have you experienced in the Michigan market? **[PROBE FOR DETAIL]**
2. How does this compare to other states?
3. Did production times change from 2019 to 2020? If so, how? What do you attribute this to?
4. What do you think production times will look like in 2021?
5. **[DISTRIBUTORS]** Have you experienced any issues with the availability of cold-climate heat pumps in Michigan? **[PROBE FOR DETAIL]**
6. How does this compare to other states?
7. Did availability change from 2019 to 2020? If so, how? What do you attribute this to?
8. What do you think availability will look like in 2021?
9. Does the timeline for cold-climate heat pumps vary by season? If so, how?

C2. **[DISTRIBUTOR]** Do you typically stock cold-climate heat pumps or do you place orders after a purchase is made?
1. How many units do you typically have on-hand? What types? Are NEEP specifications considered? What led to your decision to stock these units?
2. **[IF NOT]** What prevents you from stocking cold-climate heat pumps?

C3. Compared to other states, are cold-climate heat pumps in Michigan competitively priced?

1. Have costs been stable over time?
   [PROBE] Have costs differed from 2019 to 2020?
   [PROBE] Do you think that change is temporary?
2. **[MANUFACTURERS]** Has there been much variation in cost of parts and labor in the manufacturing of the cold-climate heat pumps?
3. **[DISTRIBUTORS]** Has there been much variation in cost based on availability of cold-climate heat pumps?

D. Demand/Adoption

I would now like to spend a few minutes talking about overall interest for cold-climate heat pumps in the market.

D1. Compared to other states, how much demand is there for cold-climate heat pumps in Michigan?

1. What do you see as the primary barriers or challenges that are restricting widespread adoption of heat pump technology in Michigan?
2. How do warranties for cold-climate heat pumps compare to warranties for other technologies (such as natural gas furnaces)?

D2. In 2020, did demand for cold-climate heat pumps in Michigan differ from 2019?

1. **[IF YES]** What do you think caused that change?
2. Do you think the change was temporary or will it be resolved?
3. Have there been any impacts on demand related to COVID-19, that you are aware of?
   [PROBE FOR DETAIL]

D3. **[MANUFACTURERS]** What feedback have you received from distributors in Michigan about heat pump technology adoption?

1. What about cold-climate heat pumps, specifically?
2. Is this different from other states?

D4. **[DISTRIBUTORS]** What feedback have you received from contractors in Michigan about heat pump technology?

1. Is this different from other states?

D5. Do you know of any promotions or trainings your organization does to increase awareness of cold-climate heat pumps among your customers in Michigan?

1. Does this differ from other states?
2. Is this different from other types of equipment?

D6. Specifically, what has your organization done to promote heat pump technology to distributors/contractors?

1. Have you offered trainings, informational pamphlets, sales/discounts, or something similar?

E. Solutions

In this final section, I'd like to shift gears a little to understand your thoughts on how Consumers Energy and other utilities could provide support to further the adoption of cold-climate heat pump technology.

E1. Is there anything you think utilities could do to improve the adoption of cold-climate heat pump technology in Michigan? **[PROBE FOR DETAIL; SOLUTIONS BEYOND INCREASING INCENTIVES]**
   1. In your opinion, where is the right place to offer an incentive to drive adoption of a newer product such as cold-climate heat pumps (downstream, midstream, or upstream)?
   2. Have you seen models for promoting the adoption of cold-climate heat pumps in other jurisdictions that Consumers Energy should consider?

E2. Are there any recent or upcoming advancements in heat pump technology that Consumers Energy should be aware of?

F. Closing

As we wrap up, I want to provide an opportunity for you to share anything I might have missed with my questions.

F1. Do you have any other comments or information you think might be useful for me to know given what we have talked about today?

F2. These are all the questions I have. As a thank you for your input, we'd like to send you a $75 gift card to Amazon, Target, or Meijer. Amazon and Target gift cards are virtual and would be sent to your email address within the next 5 to 10 business days. Meijer is offered as a physical gift card, which will be mailed to your preferred address. Alternatively, we can donate the $75 to your local United Way. Which would you prefer?
   1. Amazon
   2. Target
   3. Meijer
   4. Please donate to my local United Way

F3. **[IF G2=1 OR 2]** Could you please provide your preferred email address to receive the **[AMAZON OR TARGET]** virtual gift card?

F4. **[IF G2=3]** Let me ask the information we need to mail your gift card to the intended recipient—this could be you personally or anyone else of your choosing:
   1. First name of recipient:
   2. Last name of recipient:
   3. Could you please provide the street address we should use to send the gift card?

You should expect to receive your gift card by no later than **[DATE]**. If you have any questions, or have not received your gift card by **[DATE]**, please contact **[contact information]** and reference the Consumers Energy heat pump interview.

F5. **[IF G2=4]** In whose name should we make the donation to United Way? **[INCLUDE FIRST AND LAST NAMES OR COMPANY NAME]**

On behalf of Consumers Energy, I want to thank you for taking time to provide input, and have a great day. **[TERMINATE]**

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Full length article

Heating with justice: Barriers and solutions to a just energy transition in cold climates

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ABSTRACT

Residential heat pumps could reduce greenhouse gas emissions, but increase energy burdens, the proportion of income households spend on utility bills. We analyze utility bills, thermostat settings and energy burdens for a sample of 51 households in Michigan, half below median income. We recruit a contractor to conduct energy assessments of these households and provide them with energy retrofit recommendations, including estimated costs and savings. We find that low-income households choose similar temperature setpoints to higher-income households, but live in less efficient homes. Below-median income households, which today experience a median energy burden of 6 %, would see it rise to 10 % if they shifted to electric heat pumps from natural gas. Weatherization could offset this increase, bringing burdens down to pre-electrification levels. However, median payback is 24 years, making retrofits infeasible for the poorest. Our results are indicative of an energy poverty trap that could hinder an equitable energy transition.

Spotlights

- Converting fossil-fuel based home heating to electric could reduce pollution but make bills less affordable.
- Switching to electric heating results in low-to-moderate income households paying a high percentage of income on energy.
- Retrofitting homes could make electric heating more affordable but it is expensive and therefore infeasible.
- High-cost energy efficiency home retrofits could hinder an equitable energy transition.
- Future work will investigate homeowner attitudes regarding electrifying their homes and barriers to equitable transition.

1. Introduction

In recent years, US state policy (Climate Leadership and Community Protection Act 2020; An Act Creating 2022; Climate Commitment Act 2022)) has signaled a commitment to reducing greenhouse gas emissions by transitioning home heating from fossil fuels to electricity. U.S. federal policy has sought to use subsidies to lower the upfront cost of heat pump adoption (Inflation Reduction Act, H.R. 5376). Electrification has been projected to increase annual utility cost for households in more than half of US states (Vaishnav and Fatimah 2020; Deetjen et al., 2021), with the worst effects in cold climates (Walker et al., 2022). Rising energy costs could have a large impact on households across the income spectrum.

1.1. Literature review

Higher utility bills could increase the economic and physical hardships in households already experiencing energy insecurity. A quarter of American households spend a high proportion (>6 %) of their income on utilities, defined as energy burden (Drehobl et al., 2020). High energy burden is associated with poor health outcomes (Reames, 2016), and households with certain vulnerabilities, such as older adults, choose uncomfortable and sometimes unsafe indoor temperatures to reduce bills (Cong et al., 2022). Lewis et al. center deteriorated housing conditions concentrated in racially segregated neighborhoods in their discussion of energy insecurity, which encompasses financial, behavioral and physical hardships related to home energy use (Lewis et al., 2020).

Households with lower energy burdens are not entirely precluded from the effects of higher ongoing costs associated with heating electrification because these costs are associated with building

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characteristics that are prevalent across the US housing stock. Old homes heated by natural gas have been shown to result in the greatest operational costs for heating with a heat pump (Vaishnav and Fatimah, 2020). 64.5 million American homes use natural gas for heating and 57 % of them were built before energy codes were implemented in the US (U.S. Energy Information Administration, 2023). Knowledge of household demographics, housing characteristics, and occupant behavior are essential to understanding the barriers to equitable access to heat pumps and a just distribution of harms and benefits associated with policy that facilitates the clean heating transition.

Current research about residential energy equity includes only one or two of these critical components. Studies that quantify the link between racial disparities in energy use and housing quality (Goldstein et al., 2022; Bednar et al., 2017), and demonstrate that households of color are more likely to have trouble paying their bills (Graff et al., 2021) do not take into account behavior. Studies that evaluate specific retrofit opportunities and quantify their the savings potential by employing national scale modeling do not address behavior impacts associated with those changes (Bradshaw et al., 2014; Wilson et al., 2019). Likewise, studies that examine the economics of heat pump adoption for low income households, whether in observed system performance (Ceglia et al., 2022; Flower et al., 2020; Calver et al., 2022; Pastore et al., 2022; Liu et al., 2018) or simulations (Donaldson and Lord, 2018; Barrella et al., 2020; Liu et al., 2020; Abbasi et al., 2022; Savage et al., 2022) focus on housing and heat pump technology characteristics without an empirical analysis of occupant behavior and preferences for heating and cooling.

Several recent studies examining the energy savings potential of residential retrofits in the European context point to the importance of incorporating household behavior in home energy assessments (Palma et al., 2022; Barrella et al., 2020; Koasidis et al., 2022; Domínguez-Amarillo et al., 2020). The literature addressing the effect of energy consumption behavior on the cost effectiveness of energy retrofits in the US commonly uses economics theory and analysis. Gillingham and Palmer (2014) conducted a literature review of explanations for limited uptake of home energy efficiency including that flawed decision making could reduce the utility of energy efficiency to customers. Three studies followed that examined this question using home energy efficiency project data from the US Department of Energy Weatherization Assistance Program (WAP). Zivin and Novan (2016) measure the treatment effect of retrofits on energy use of 275 households and provide evidence that electricity savings due to WAP are overstated. Allcott and Greenstone (2017) and Fowlie, Greenstone and Wolfram (2018) use large samples of primary empirical data to estimate the benefits of providing energy efficiency services to low-income homes. Though these studies consider behavioral explanations for under performance of projects compared to engineering estimates, they do not provide detail on the housing conditions prior to intervention or the specific work performed. See Table C.7 for a comparison of this paper's contributions to those of the literature.

Other large empirical studies that address impacts of high utility costs on vulnerable households similarly do not provide data on the housing characteristics of the populations they examine (Cong et al., 2022; White and Sintov, 2020), and therefore do not address why these impacts occur. Although Booth and Choudhary (2013) estimate the rebound effect, identify specific upgrade parameters, and focus on public housing in their assessment of uncertainty in retrofit performance (Booth and Choudhary, 2013), they do not address the transition in heating technology. Recent research has signaled the potential for heat pumps to contribute to residential sector clean heating transition where countries push for climate action and fossil fuels remain the predominant fuel source (Fitó et al., 2021; Thomaßen et al., 2021; Besagni et al., 2020).

1.2. Research gaps

There remains a gap in quantifying the impacts of residential heating electrification across income and in examining interventions specific to both housing quality and energy consumption behavior. Previous studies that have taken this form to assess the reasons for disproportionate impacts of energy cost across income (Cong et al., 2022; Jones et al., 2023) only examine it in the context of air conditioning, not heating. To bridge this gap, this study aims to disentangle the sources of inequality embedded in the economic impact of heat pump adoption and assess fixes available for real homes. The present work has three main contributions. First, we provide evidence that energy burden impacts across income are associated with housing quality rather than behavior. Second, we compare economic impact of heating fuel transition across income groups. Third, we test the idea that there is a way to mitigate the utility cost premium for heat pumps.

We conduct a year-long field study of 51 homes in Southeast Michigan, during which we perform a comprehensive energy audit of each home to observe envelope and HVAC system characteristics, including thermal imaging to identify temperature gradients indicative of air leakage and poor insulation, and blower door testing to measure air infiltration rate, as well an examination of the on-label efficiency of all appliances. We gather metered daily gas and hourly electric consumption data over the study period and collect energy assessment contractor recommendations for energy efficiency retrofits for each home. Our approach to examining residential energy equity is novel because we compare results derived from observed data with simulations derived from statistical sampling of large public data sources (Wilson et al., 2022).

Following this introduction, we present the methods, then results, then we will discuss the findings and conclude. We present our findings in five parts. First, we examine the existing conditions of the homes in the study and compare them across income, including key housing characteristics and indoor temperature preferences. Next, we quantify the impact that replacing natural gas heating with heat pumps would have on household energy burden. We then examine the sensitivity of time of use utility rates on the annual energy bill impact of fuel switching. Following that, we quantify the cost savings potential of energy efficiency envelope improvements and compare it to the utility bill impact. Finally, we explore energy efficiency retrofit recommendations provided to participants during home energy audits and assess the feasibility of these improvements to mitigate the ongoing cost impact of heating electrification on the sample.

2. Methods

This study uses observed household energy use and indoor temperature data along with a reduced complexity air source heat pump coefficient-of-performance model to determine energy cost and energy burden impacts of switching to a heat pump. We gather energy retrofit recommendations and estimate upfront costs, energy cost savings, and payback from a contractor who conducted a detailed energy audit for each home. We then quantify annual utility bill impacts for fuel switching and energy retrofits using a building energy model that provides detailed sub-hourly simulations a large sample of archetypal homes that are representative of the study region and compare them to our findings for the sample.[1]

[1] See Data Availability statement for more information on how to access data that can be made available under the Institutional Review Board guidelines for human subjects research. See Supplemental Methods for additional detail on justification for model and calculation assumptions and Supplemental Figure, Tables, and Notes for detail on participant demographics, supporting findings, and literature review.

2.1. Participants

As described below, we recruited 51 participants from Wayne and Washtenaw Counties in Michigan, which encompass the Detroit and Ann Arbor metro areas. We chose Southeast Michigan for three factors that make this study applicable to global contexts including the Midwest, New England, and the Mountain West regions of the US; Northern Europe; and the United Kingdom: cold climate, predominance of natural gas for heating, and older homes.

Participant recruitment included three steps. First, we circulated an expression of interest form through local media, university email lists, and local environmental and energy justice community groups that drew more than 1300 responses. Second, we asked these respondents to complete a demographic survey to assess the presence of key factors associated with energy insecurity: race, income, disability, children, and health vulnerability (Drehobl et al., 2020; Reames, 2016; Hernández, 2016). We received 883 responses to the demographic questionnaire. Third, we identified a random sample stratified using survey answers to ensure representation across four key, binary, classes of vulnerability: has a disability, has at least one child at home, foregoes paying energy bills at least once a year, controls heating or cooling for a vulnerable occupant. These four classes correspond to 16 combinations, and we had respondents who corresponded to only 10 of them.

Next, we identified 418 survey respondents living in single family homes. We then classified the respondents into 10 categories representing the unique combinations of the key categories listed above. We calculated how many households we would need to invite to have an equal number across these categories and randomly selected that many households from each group. Where the quantity of respondents in a category was not great enough to provide an equal weighting, we invited all the respondents in the category. Ultimately, we compiled a list of 90 potential participants to whom we sent invites to join the study. Our recruitment rate was 58 %. Demographic questions and descriptive statistics can be found in Note D.3 and Table C.1. 90 respondents were asked to join the study. Demographic questions and descriptive statistics can be found in Note D.3 and Table C.1.

All households in the sample live in single family homes. 50 of the 51 households are homeowners; 1 is a renter. All homes use natural gas for heating with the exception of 1, which uses propane. The sample includes a diversity of housing vintage (i.e. common building practices) from every decade since 1900: 9 homes were built before 1940, 17 homes were built between 1940 and 1960, 12 built between 1961 and 1980, 6 built between 1981 and 2000, and 7 built after 2000.

The study sample is representative of the populations of the two counties of Southeast Michigan along two key characteristics. (1) Income: the median income (in 2022 dollars) is $57,223 for Wayne County and $84,245 for Washtenaw County (U.S. Census, 2024). The sample includes 11 households reported earning annual income <$25k, 18 earning $25–50k, 9 earning $50–75k and 13 earning >$75k. (2) Race: 54.6 % white, 38.3 % Black, and 7.1 % all other races in Wayne County and 73.9 % white, 12.4 % Black, and 13.7 % all other races in Washtenaw County (U.S. Census, 2024). The sample includes 29 % Black ($n = 15$), 45 % white ($n = 23$) and 25 % ($n = 13$) all other races, including one participant who prefers not to answer.

Households were provided $100 compensation.

2.2. Data collection

We obtained one year of utility data for each household, including hourly metered electricity use and daily metered gas use where available. We conducted one visit to each home, during which we installed a smart thermostat where the heating and cooling system could accommodate the product (Ecobee 3 lite) ($n = 40$). For homes that could not receive the smart thermostat, we set up a wi-fi connected thermo-hygrometer (Govee H5179). Both devices record data at 15-minute intervals. An accredited energy audit contractor accompanied the research team and performed an ASHRAE Level 2 energy audit at each home.

Participants provided income ranges, so we estimate energy burden based on the arithmetic midpoint, i.e., if a participant reports their income to $25k-50k, the energy cost burden for that household was calculated at the proportion of their actual annual utility bills to $37.5k. We did not apply an equivalence scale to energy expenditure and income because we observed occupancy in some homes to which the published equivalence scales would not readily apply, for example, households with adult children that may live at home for periods of time varying duration and frequency throughout the year. See Supplementary Methods for detail on energy burden calculation.

2.3. Housing quality analysis

To assess participant behavior, we estimate indoor temperature setpoints in two ways. First, we estimate the heating inflection temperature (HIT) (ambient temperature at which a household begins heating) for each home using a splitwise regression of metered daily gas use on hourly average ambient air temperature (obtained from NOAA Local Climatological Data (LCD) for the data collection period). Second, we evaluate the observed heating and cooling setpoints and the observed indoor temperature for the heating and cooling season for a subgroup that received a smart thermostat ($n = 40$). We calculate cooling and heating season means for setpoint temperature as well as the standard deviation for setpoint and indoor temperature using this interval data.

2.4. Heat pump cost analysis

Our energy cost analysis for switching to all-electric heat pumps from natural gas-based heating consists of three steps. See Appendix A for detailed calculation methodology and model specifications.

- *Heat load calculation. Existing furnace gas use.* To determine heating natural gas use, we first estimated the inflection point for temperature dependent gas use using a split-wise regression of heating degree hours (a measure of the intensity of the space heating needed for a given time and place) on hourly total gas use. We assumed that the slope of the piecewise linear function (found with the segmented() function in R) past this inflection point indicates heating related natural gas usage. From that, we derived the slope which is the natural gas usage per heating degree hour. We then obtained the amount of gas used during each hourly time step for heating by multiplying the slope by the difference between the outside ambient air temperature departure from the indoor heating setpoint gathered during the initial data collection period when the energy audit took place.

Deriving heat load. We multiplied the hourly gas use by the furnace efficiency to obtain the hourly heating load for each house. We obtained the hourly ambient temperatures for each home during the window of time the utility data was provided by the utility (e.g. 11/10/2020–11/11/2021) using the NOAA Local Climatological Data (LCD) Tool for the closest available weather station.

- *Heat pump model.* We calculated the heat pump hourly temperature-dependent coefficient of performance (COP) using the following equation:

$$COP_i' \times (1 - l(t_i)) = COP_i \; Tmin < t, \; i \in 8760$$

$$COP_i = 1 \; t < Tmin$$

Where:

***i* indexes hour;**

***COP'* = manufacturer reported coefficient of performance** using the efficiency curve (ambient temperature vs. COP) of the Mitsubishi M2i cold climate ASHP for heating;

***l()* = defrost efficiency loss for give temperature, t (%);**

t = **hourly dry bulb temperature (F)** using the NOAA LCD weather data for the same period for which had metered natural gas data for each home;

COP = observable coefficient of performance;

$T_{min} = 10°F$ reflecting ambient temperature change over point from heat pump to backup heating mode via electric resistance coil;

$<T_{min}$ **COP** $= 1$ reflecting the heating efficiency of an electric resistance coil used for backup to ensure that heating setpoints are met below the change over point.

We calculated percentage improvement in cooling energy by dividing the Mitsubishi H2i SEER rating (SEER = 17) by the on-label AC efficiency obtained from the energy audits for each home. This kind of high efficiency equipment comes with a first cost premium over a standard furnace replacement. It is therefore expensive for low- and middle-income households and is likely not affordable without a subsidy that covers most of the cost. Selecting this equipment is a conservative assumption. We then applied this factor to an average cooling energy percentage obtained from the Resstock End Use Savings Shapes (Wilson et al., 2022) to determine the annual energy cost savings.

- *Energy cost calculation.* We calculated the energy cost using a model we developed in R that takes in the hourly estimated electric and daily gas usage for the hypothetical heat pump scenario and calculates the total bill costs in the manner calculated by the utilities as published in the electricity and gas rate schedules ("DTE Electric Company Rate Book for Electric Service", 2023). For example, to calculate the annual electricity cost for each home, we apply the flat rate service charge per month, capacity and non-capacity energy charges assessed per kWh, as well as surcharges and credits. We completed this process for three electricity rates and two gas rates to test the sensitivity of our results to rates available to participants. See Figure B.7 for rate summary and Note D.5 for rate description. We do not include tariff changes from one year to the next because future rate changes are unpredictable and beyond the scope of the analysis. Changes in consumer behavior associated with changes in utility tariffs are also beyond the scope of the paper and therefore not included in the analysis. Additionally, incorporating behavior changes would not have a meaningful impact on the results because short term elasticities are low for electricity and natural gas in the US (U.S. Energy Information Administration, 2021).

2.5. Resstock

We analyzed the potential for energy efficiency to mitigate cost increase due to heat pumps by calculating energy costs derived from four modeled retrofit scenarios included in the NREL Resstock End Use Savings Shapes database (Wilson et al., 2021). We selected hourly load profiles available for a baseline case and three "upgrades" including full electrification with or without deep efficiency retrofits, and deep efficiency retrofits with no change to the HVAC systems. To these scenarios, we applied the utility rates for all sensitivity cases as described above. We then calculated the mean incremental annual energy costchange resulting from a series of these changes across a random sample of 400 homes in the database representative of Detroit, MI.

2.6. Retrofit cost analysis

The contractor recommended energy efficiency measures and provided first cost and utility cost savings estimates for the recommended work. We used the "Return on Investment and Rebate Report" prepared for each study participant to summarize the recommended energy efficiency upgrades to code the unique efficiency measures recommended across the sample.

The parameters we used for estimating the feasibility of retrofitting were economic payback in years for the package of all recommended retrofits (calculated as the first cost divided by the annual energy cost savings), the first cost of the total package, and the modeled utility cost savings for the individual measures. The values for these parameters were obtained from the retrofit reports provided to participants by the energy audit contractor. The payback parameter described above follows the US Department of Energy Methodology and Procedures for Life Cycle Cost Analysis (Code of Federal Regulations. 10 CFR Part 436 Subpart A). No discount rates are used, making this the best-case estimate of the payback period. Given our findings, the decision to use an undiscounted payback period is conservative: if a discount rate were applied, the payback period would be even longer, strengthening our argument that the retrofits are not attractive on the basis of utility bill savings. Additionally, we show the rates that participants were provided as part of their energy audit, so payback periods not inclusive of a discount rate are more representative of the data participants have to inform their decision making.

3. Results

We find that electrifying homes with heat pumps increases annual energy cost by 58 % on average (range: 11–182 %) when compared to natural gas heating and considering a flat electricity rate, higher than previous estimates. This change exacerbates already high energy burdens for low-and-moderate income (LMI) households. While we find energy retrofit opportunities that saved energy cost for every home, they came with substantial obstacles that could limit uptake. There is an average payback period of 24 years and homeowners can be left without sufficient information to act, even after a visit from a home energy auditor. Willand et al. (2020) identified this situation as the retrofit trap in their 2020 analysis of Australian home retrofit programs. It can be understood as a form of poverty trap, defined Azaiadis and Stachurski as a reinforcing mechanism that acts as barrier to adoption of techniques that can alleviate poverty (Azariadis and Stachurski, 2005). The clean energy transition is hindered by an energy poverty trap because the extensive retrofits needed to make electrification affordable are themselves too expensive for low-income households.

3.1. Housing quality vs. set-point choices

We estimate energy burden for each household by calculating the proportion of their annual combined electricity and gas cost (sourced from utility bills) to the self-reported income range. The 5 highest energy burdened households have rates ranging from 10 to 40 %. 32 % of homes have energy burdens greater than 6 %, which is considered a high energy burden and twice the national average (Drehobl et al., 2020). All these households have below-median incomes. 37 % are between 3 and 6 %. 31 % of homes have an energy burden below 3 %; all but one of these homes have incomes that exceed the local median (see Figure B.1). See Table C.1 for descriptive statistics on utility costs and energy burden. Table C.6 provides a list of self-identified household income ranges and a comparison to the area median income (AMI) by zip code.

Not all homes in our sample were of the same age and quality. The homes were on average 60 years old and built in an era during which Michigan did not have energy efficient building codes.[2] These codes were adopted for the first time 1977 when ASHRAE 90–1975 was adopted state-wide ("US Dept. of Energy Building Energy Codes Program", 2024). 13 homes (5 in the <$25k income group and 8 in the $25–50k group) had been retrofit by Habitat for Humanity of the Huron Valley (Habitat) resulting in higher quality for their age. Improvements had been made 1–10 years prior to participating in this study.

Homes retrofit by Habitat perform consistently better than market rate homes in the sample [Fig. 1]. To understand the impact of these

[2] They were adopted for the first time 1977 when ASHRAE 90-1975 was adopted state-wide. (US Dept. of Energy Building Energy Codes Program, www.energycodes.gov/status/states/michigan).

retrofits on overall home energy efficiency, we examine the difference between trends of annual energy use per unit floor area (or energy use intensity) and per occupant across income in market rate homes compared to the Habitat homes. When treating self-reported income categories as an ordered set (<$25k, $25–50k, $50–75k, and >$75k) in a least squares regression of energy use intensity (EUI) per occupant on income, we find a significant downward trend (p-value=0.048) for market-rate homes, indicating that low-income households either live in less energy efficient homes or there is significantly different behavior across income levels.

The latter explanation would suggest, for example, that lower-income households start to use heating at higher ambient temperatures and cooling at lower ambient temperatures. Cong et al. provide evidence to the contrary. They find that lower-income families wait for ambient temperatures to rise higher before turning on air conditioning compared to those with higher incomes (Cong et al., 2022). This would imply that low-income families use less energy, a seeming contradiction of our results. However, we believe that there is no contradiction, since the Cong et al. results are not directly comparable to ours for two reasons. First, we report energy use per square foot per occupant, which Cong et al. do not observe. Second, Cong et al. have studied air conditioning, whereas energy use in our sample is dominated by heating. Huang et al. (2023) do find evidence that low-income households start to heat earlier in the season and heat for more months of the year than higher-income households. However, these results are also not comparable to ours since there is no normalization by area or occupancy. We estimate the heating inflection temperature (HIT), or the outdoor temperature at which each household turns on the heat because in every case heating constitutes the highest proportional energy expenditure (>60 %). To estimate the HIT, we calculate a linear splitwise regression of metered daily gas use on ambient air temperature. We find no significant trend in HIT across income (see Figure B.2). Combined, our findings and those of Huang et al. (2023) suggest that behavior-driven energy use patterns are unlikely to explain the higher energy use of low-income homes.

Observed heating and cooling setpoints—read from participants' smart thermostats—likewise reveal that lower income households do not on average choose higher setpoints in winter or lower setpoints in summer [Fig. 2a]. We do observe greater variance in the set points that households in the lowest income group (<$25k) choose [Fig. 2b], as well as in the indoor temperatures that they experience [Fig. 2c]. This suggests that, even though they have higher energy use intensity, these households are actively trying to manage their energy use and comfort by manipulating their set points. This provides evidence that the higher EUI is in fact due to poorer building envelopes and not because lower-income households are choosing consistently different setpoint temperatures.

We look at housing characteristics to explore whether the homes occupied by low-income households are in fact less efficient. Blower door testing conducted at each home provides an empirical measure of efficiency by measuring air infiltration. Low infiltration signifies high efficiency. We find that the homes retrofit by Habitat have better performance than market-rate homes in the sample. The median measured air infiltration rate of Habitat homes is almost half that of their counterparts (4.2 ACH 50 and 7.7 ACH 50, respectively) with less variability (range: 2.9–5.9; IQR = 3.4–5.3 and range: 3.2–17.5; IQR = 5.8–10.9, respectively). Applying the same regression method described above, after excluding Habitat homes, we find a significant downward trend (p-value = 0.023) for market-rate homes, indicating that the lower-income homes are indeed less efficient (Figure B.3).

3.2. Energy burden

For the 51 houses in our sample, we calculate the electricity loads that would result from replacing natural gas furnaces with air source heat pumps for space heating (see Supplementary Methodology for more detail on reduced complexity model and load derivation) and apply the most prevalent gas and electric utility rates across the sample to determine the energy cost change associated with this replacement. We calculate change in annual energy bills and energy cost burden which refers the difference in energy expenditures and percentage of income spent on utilities, respectively, between the baseline scenario and the heat pump scenario. 41/51 households were on a standard time-invariant rate, which will be discontinued as of May 2023. 10 had elected different rate structures, which include time-of-use rates, interruptible cooling rates, and specialty rates designed for low-income households. We find that switching to a heat pump would increase annual utility bills for every household in the sample, and that the cost goes up by $1154 on average (see Table C.3).

Our results show variability in median cost change across income and a disproportionate concentration of high energy burden increase below median income (<$25k and $25–50k). The median cost increase for below median income households is $801 ($n = 28$), constituting a 37 % utility spending increase on average. There is a 49 % utility spending increase for above median income households on average ($n = 22$) [Fig. 3a-1]. Even though the median cost increase is nominally lower for

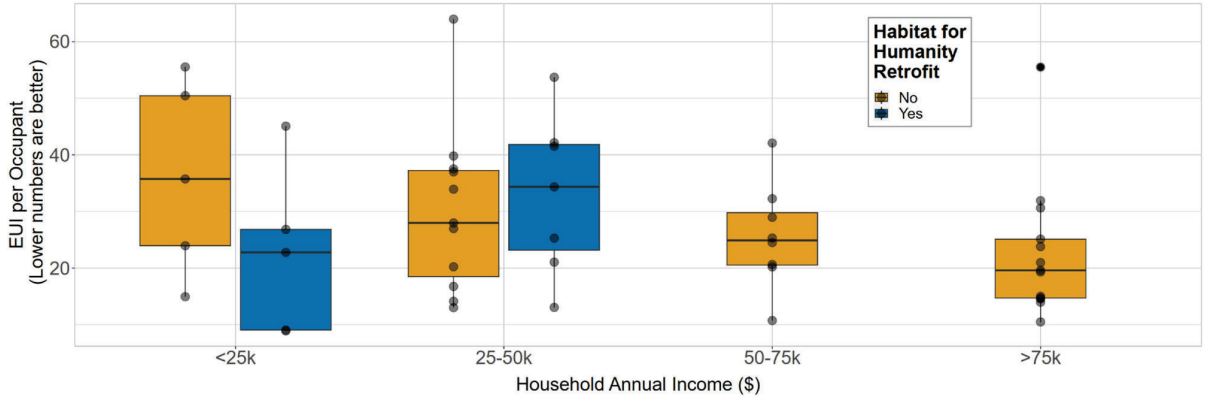

Fig. 1. Energy use intensity per occupancy by income group. Annual energy use per floor area divided by the number of occupants is shown here. The x-axis represents four income categories to which participants were assigned given the income range they provided. Each box plot shows the median (middle line), first and third quantiles (lower and upper box bounds), and minima and maxima (whiskers). The blue boxes represent homes that have been retrofit by habitat for humanity, which perform better than market rate homes in the sample (represented by oranges boxes) for homes earning less than $25k. Each dot represents one household. Using a non-linear least squares regression, we find a significant downward trend (p-value = 0.048) among market rate homes, indicating that those with lower incomes live in less efficient homes.

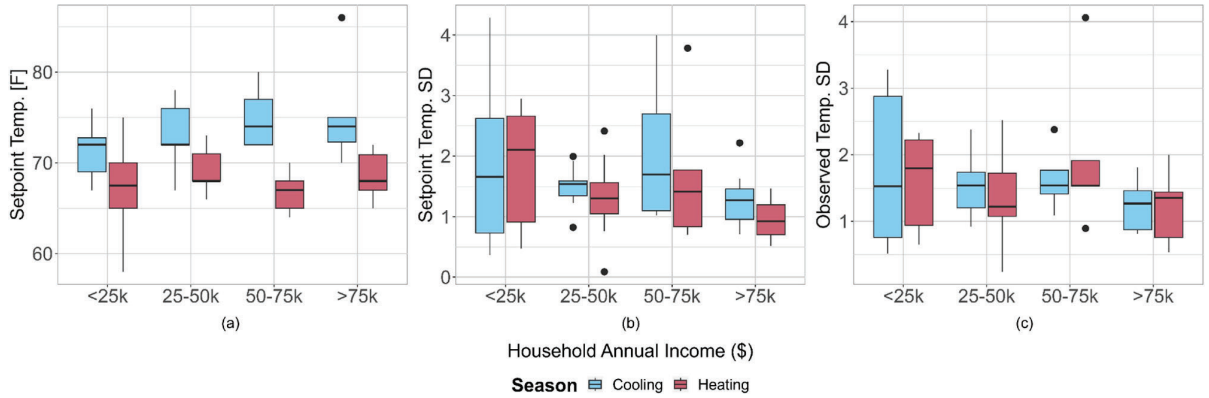

Fig. 2. a-b-c: Thermostat setpoint and observed indoor temperature by income. Observed heating and cooling setpoints (a), setpoint standard deviation (b), and indoor temperature standard deviation (c) on smart thermostats for each home.

below median income households, their energy burden increase is 4 times higher on average than those at or above median income [Fig. 3b-1]. Additionally, all households earning median income ($50–75k) and above (>$75k) - which currently have a median energy burden of 2.6 % – would experience a median change in energy burden of greater than 1 percentage point, indicating that energy burden could become a concern for households which are currently energy secure.

3.3. Time of use electricity rates

We examine the impact of two time-of-use rates available to all customers in the study region on the annual increased utility costs and energy burdens of the sample for a hypothetical conversion to heat humps. Switching to the standard time-of-use rate (DTE no. D1.11) ("DTE Electric Company Rate Book for Electric Service", 2023) reduces the mean cost increase for the sample by $120 per year from $1154 to $1034 (see Fig 3a-2) relative to a flat rate. Under this rate, the median

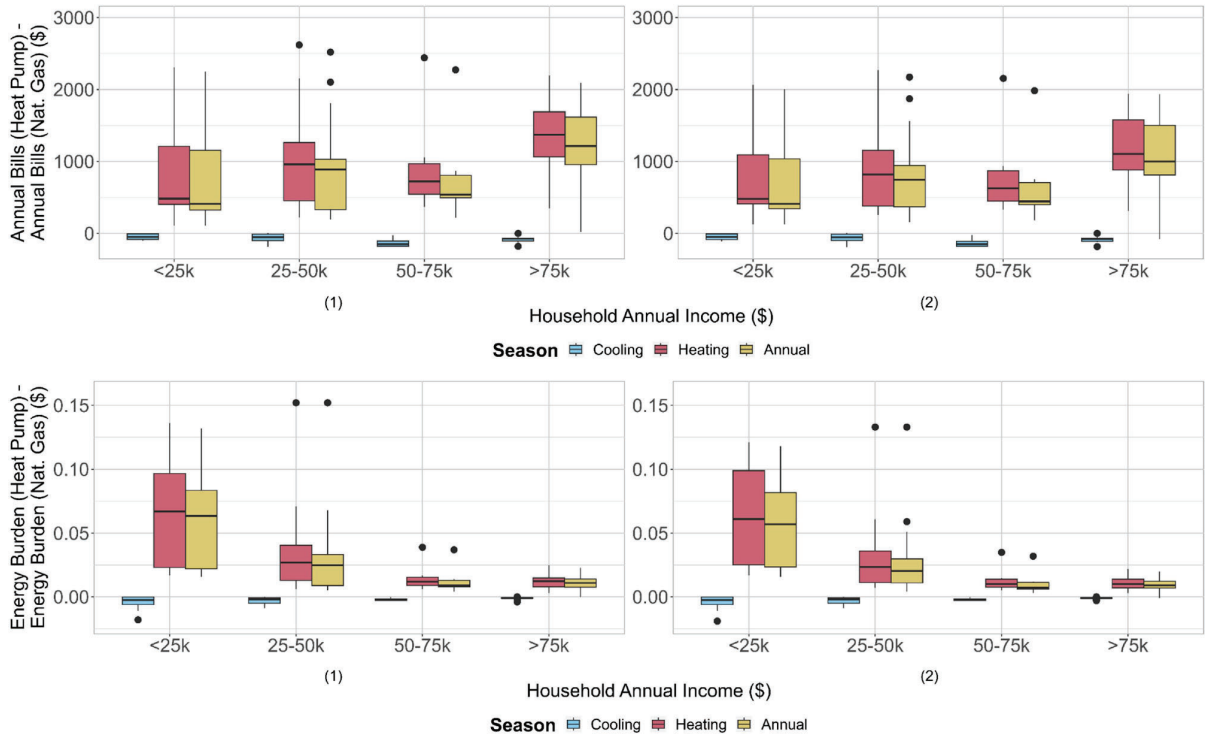

Fig. 3. a: Change in annual energy bills for switching to a heat pump from natural gas heating by income. The x-axis represents four income categories to which participants were assigned given the income range they provided. Dot represents outliers. Each box plot shows the median cost increase (middle line), first and third quantiles (lower and upper box bounds), and minima and maxima of change in utility cost change for (1) standard flat electricity rate and 2022 natural gas cost; (2) standard time-of-use electricity rate and 2022 natural gas cost.
b: Change in energy burden for switching to a heat pump from natural gas heating by income. The x-axis represents four income categories to which participants were assigned given the income range they provided. Dot represents outliers. Each box plot shows the median energy burden increase (middle line), first and third quantiles (lower and upper box bounds), and minima and maxima of change in energy burden change for (1) standard flat electricity rate and 2022 natural gas cost; (2) standard time-of-use electricity rate and 2022 natural gas cost.

utility cost change due to heat pumps is lower for every income category. The effect of this lower cost change is minimal for energy burden, reducing the rate by less than 1 percentage point for each category [Fig 3b-2].

By comparison, relative to a flat rate, the optional time-of-use rate (DTE no. D1.2) (DTE Electric Company Rate Book for Electric Service, 2023) would worsen the increase in annual utility cost for switching to a heat pump for all income groups. Switching to D1.2 increases the mean cost increase for the sample by $623 per year to $1777 (see Figure B.4). This rate nearly doubles the median energy burden changes for all income groups earning less than $75k (see Figure B.5). The D1.2 rate had a higher cost per kWh at peak times and a peak window two hours longer than the D1.11 rate. These rates impacted each household differently given the variety of occupants, schedules, housing vintage across the sample. For instance, those who saw the greatest cost increase with the standard time-of-use rate had the oldest, least efficient AC units in the sample and used their cooling systems during the peak window, whereas, in reality, the switch to a heat pump would include a new, more efficient AC.

While the gas commodity prices have risen dramatically from 2021 to 2023, the delivered price of natural gas for residential customers has in fact been modest and does not affect the results. See Figures B.4 and B.5 for a comparison of annual bill and energy burden changes with 2021 and 2023 gas rates. See Table C.2 for a detailed comparison of all of the electricity and gas rates available to DTE customers as of 2023 and their impact on baseline household energy use.

3.4. Energy retrofit model

Energy retrofits are a possible strategy to mitigate this increase in bills. Since we do not have empirical estimates of cost savings potential of envelope improvements to mitigate the cost increase of heating electrification, we first model the corresponding energy uses using the NREL ResStock End Use Savings Shapes (Wilson et al., 2022). We randomly sample 400 Michigan homes heated with natural gas from the database and examine four scenarios: baseline envelope with natural gas heating, envelope upgrade, heat pump upgrade, and combined heat pump and envelope upgrade. To then convert the energy uses to cost, we apply the electricity and gas rates experienced by 41/51 of our study participants to the hourly electricity and gas loads to estimate the relative cost impact of retrofits for the natural gas scenario and the heat pump scenario.

We find that transitioning to a heat pump without energy retrofits results in a mean utility cost increase of 26 % over the baseline. Adding a comprehensive envelope retrofit improvement mitigates this cost premium and drives utility costs back to what they were with natural gas heating with the existing envelope. Energy efficiency retrofits alone reduce bills by 11 % compared to the baseline condition [Fig. 4].

See Note D.1 for a comparison of the modeled results to the estimates calculated using observed data from the field study, including a breakdown of model findings by house vintage (Figure B.6).

3.5. Contractor retrofit recommendations

Our results suggest that, with energy retrofits, most homes would not experience an increase in utility bills relative to the status quo if they shifted to heat pumps. Based on REM/Rate (REM/Rate 2024), commonly used software, our contractor recommended a different combination of ten individual retrofit measures for the homes in our sample and these upgrades are expensive with long payback periods. The most commonly recommended measure is air sealing, an intervention in which joints are sealed to reduce air infiltration. We classify building envelope upgrades as simple if they can be completed by one contractor (e.g., spraying cellulose in the attic) and complex otherwise (e.g., foam injection into drywall). Upgrades to the HVAC system are in a separate category, as are upgrades to other appliances (e.g., fridges) (see Figure B.8). The median retrofit package costs are about 10 % of household income. ($3250 for <$25k; $4700 for $24–50k; $10,300 for $50–75k; $7000 for >$75k) (see Figure B.9). 14 households in the lowest three income groups are faced with total package costs of more than 20 % of their income. The median payback period across the sample is 24 years, with a large variance across the income groups (see Figure B.10).

Upfront cost and simple payback estimates for retrofits match previous studies. Fowlie et al. (2018) use empirical estimates for actual energy savings across the Michigan WAP and find internal rates of return (IRR) at −10.6 % (10 year), −2.3 % (16 year), and 0.21 % (20 year). We find even lower IRR for the recommended retrofits by the energy

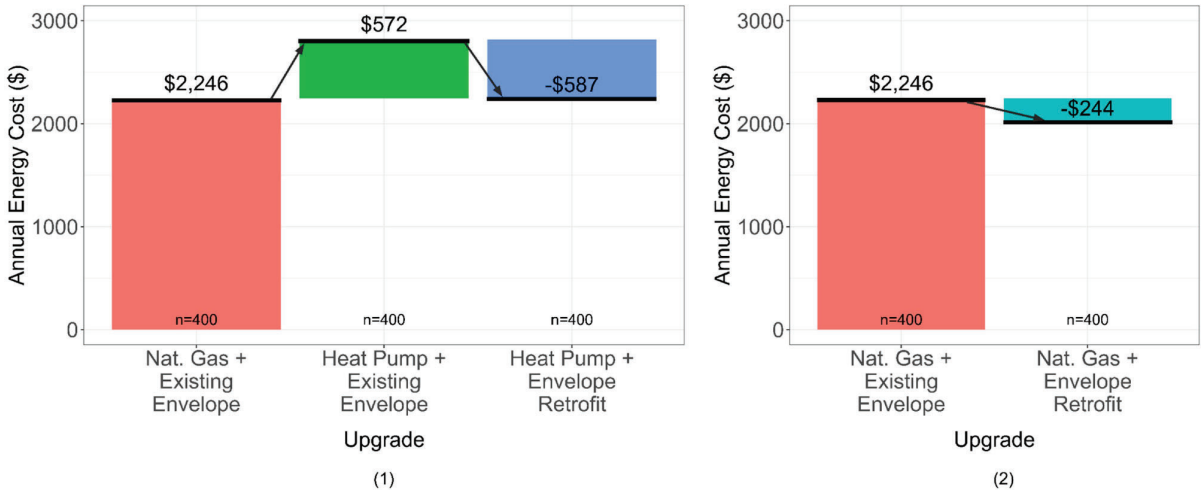

Fig. 4. Modeled mean annual energy cost impact of heating electrification and envelope improvements. (1) The baseline case (natural gas heating with existing envelope) represented in red is compared to two upgrades: heat pump with efficient envelope retrofit (green) and heat pump without envelope improvements (blue). (2) The baseline case (natural gas heating with existing envelope) represented in red is compared natural gas heating with efficient envelope retrofit (teal). Means represent 400 randomly sampled homes from the ResStock end use load profile database that use natural gas in Michigan. Using a Kruskall–Wallace test, we find a significant difference between the medians of the utility costs in each upgrade category (p-value < 0.01). We test the null hypothesis that the medians were the same using a pairwise with the Bonferroni adjustment and similarly find significant differences for each comparison.

assessment contractor: −16.1 % (10 year), −5.3 % (16 year), and 2.2 % (20 year). Less et al. (Less et al., 2021) estimate an archetypical retrofit package for a single family house that includes the most common retrofit recommendations in our sample (attic floor insulation, air sealing, foundation floor insulation) based on actual US construction costs at $7825 (see Note D.2 for measure cost calculation). The mean upgrade package cost estimated by the energy audit contractor in our sample is $7628 and the median is $5900 (see Figure B.9). Since the package described by Less et al. excludes system or appliance measures, we surmise that it is likely our contractor's costs are underestimates. Realized project costs could be higher, and payback periods longer.

There is no clear pattern about what measures are most cost-effective. The results show a large range of annual cost savings available from the recommended retrofit packages, with annual utility bill savings ranging from $26 to $730 [Fig. 5a]. We find that air sealing, which was recommended to all households, provides a payback range of 3.7 to 144 years [Fig. 5b] and attic insulation alone provides a payback range of 20 to 259 years (see Note D.2 for measure cost calculation). The high-end estimates that reflect payback periods much higher than seen in the literature are due a sample-specific scenario in which 25 % of the homes in the study received energy efficiency retrofits before the study period. For these homes, which were already high performing, the contractor recommended improvements to existing conditions (such as attic insulation and air sealing), which resulted in marginal energy savings and therefore long payback periods.

4. Discussion

We explored the drivers of energy inefficiency, explored the economic impact of replacing natural gas furnaces with heat pumps by income, assessed a range of energy retrofit measures that could support utility cost reduction in the 51 Michigan households we studied, and compared this impact to estimates from a national model. Heat pumps raise energy cost and energy burden disproportionately for low-income households. The median utility cost increase for switching to a heat pump is lowest for low-income households because they use the least amount of energy. This finding is suggestive of an efficiency paradox (Goldstein et al., 2022) where the lowest consuming households live in the least efficient homes, indicating that they are likely not using enough energy to meet their health, safety, and comfort needs. Yet, the increase in energy burden is disproportionately higher for low-income groups because even though their cost increase is nominally the smallest, it is a greater percentage of their annual income. Our results show that adopting heat pumps results in a fmedian energy burden increase of 75 % and 54 % for both income groups earning below AMI (<$25k and $25–50k, respectively). Given that households below median income have a 6 % median energy burden on their existing natural gas heating systems, such increases would severely worsen existing energy insecurity, for instance increasing risk of poor health (Reames et al., 2021) and coping behaviors like trading off paying utility for paying for rent or food (Hernández, 2016), or the underconsumption of energy in household who struggle to pay their bills (Meyer et al., 2018; Barrella et al., 2022; Faiella and Lavecchia, 2021; Antepara et al., 2020).

Policymakers should act to help lower the operating costs of heat pumps compared to natural gas for low-income households in cold climates. This can be done in three ways. First, government-sponsored initiatives to advance more efficient heat pump technology like the U.S. Department of Energy Residential Cold Climate Heat Pump Challenge are essential to improve energy bill affordability of fuel switching. More efficient heat pumps reduce the utility cost premium over natural gas furnaces.

Second, state regulators should exercise a more robust scrutiny of utility company returns and create more opportunities to improve customer outcomes in the rate making process. For example, the Michigan Public Service Commission recently ruled in a disputed rate case in the study region that resulted in allocations for energy retrofits in historically underserved areas due to intervening efforts from customer groups not typically represented in rate making like community

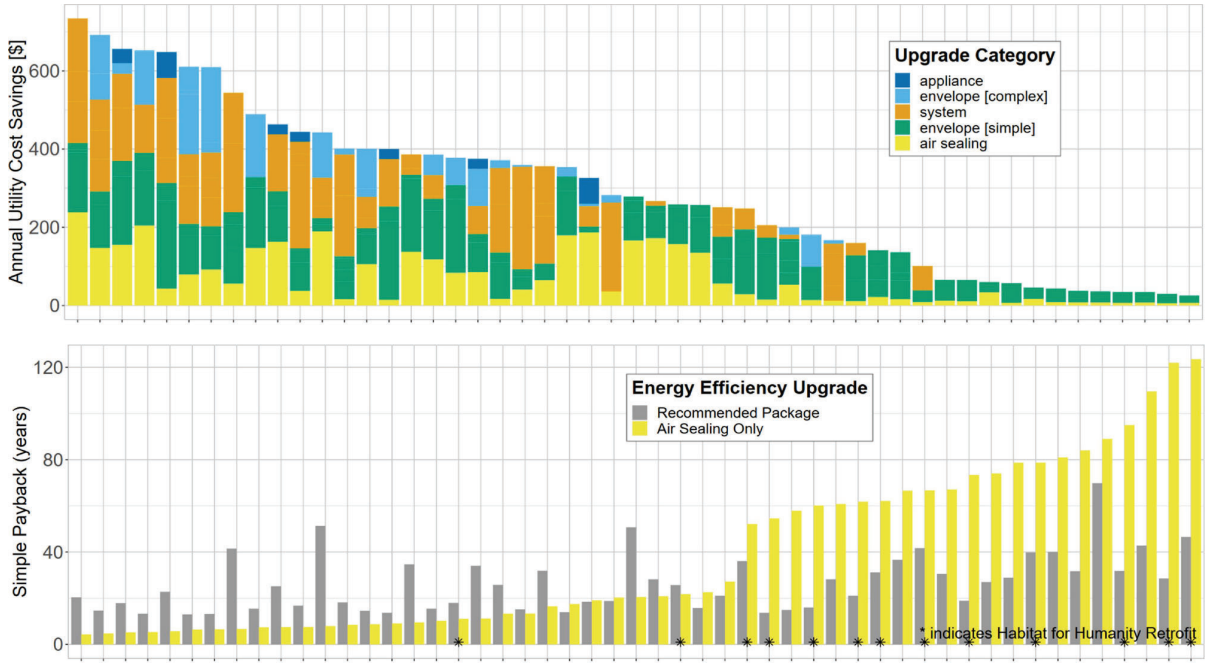

Fig. 5. a: Annual utility cost savings for retrofit packages by household. Colors represent categories we develop to indicate the relative cost and difficulty of adopting the recommendation. There is no clear pattern for which energy retrofits provide the best payback.
b: Simple payback for the recommended package and air sealing by household. Gray bars represent the payback for the full retrofit package recommended for each home. Corresponding yellow bars represent the air sealing payback period for that home. Star indicates houses that have been retrofit by habitat for humanity.

advocates and municipal governments (Hon et al., 2023). A high ratio of per-unit electricity to gas rates makes heat pumps less attractive than natural gas furnaces.

Third, states should consider implementing percentage of income payment plans (PIPP) that place a cap on energy expenditures relative to household income. These programs can be paired with federal- and state-funded retrofit programs to simultaneously improve the building stock and mitigate energy poverty. Capping household utility costs insulates low-income households from increase in bills.

Local factors exacerbate the economic penalty for household heating electrification described in this study and pose additional barriers to change not found in other regions. In our study sample, the average electricity cost is $0.18 per kWh and gas costs $0.8 per 100 cubic feet, or $0.03 per kWh. Per unit energy, electricity is therefore 5 times more expensive than gas, which is a large-enough difference that the higher efficiency of heat pumps is unable to compensate for it. (See Table C.4 for energy burden changes by income). Our results show that under these circumstances, energy cost increases for heating electrification could be disruptive even for households earning twice the median income.

Low-income households will need expanded and flexible financial assistance to retrofit their homes to prepare them for electrification. The subset (25 %) of homes that received deep energy retrofits prior to the data collection period had consistently more efficient air sealing and attic insulation than the market-rate homes. Retrofits to improve the performance of these characteristics were the most frequently recommended to study participants by the contractor, but we found they had a large range in payback period. There was no clear best choice investment that would provide either the greatest utility savings or the best payback, making it difficult for policymakers to make broadly-applicable recommendations for energy efficiency retrofits.

The group of very low earners (<$25k) with low energy burdens living in highly efficient homes were the same households that experienced the lowest energy burden increase due to heat pumps. This demonstrates the value of energy efficiency improvements in buffering households from the impact of utility cost rise due to electrification. However, the retrofits that provide the remedy are expensive. Our findings suggest that actual upfront costs for recommended retrofits in homes that have not been renovated far exceeded the $7700 cap for the Weatherization Assistance Program. Additionally, the payback periods in many cases were so high the projects would not qualify for the program, which requires a 1:1 saving-to-investment (SIR) ratio without consideration of discount rates. Current programs need to be expanded to cover the cost of expensive upgrades, and to be made available to more homes.

5. Conclusions

Policy action is needed to make heating electrification viable. The economics of electrification are adverse for the existing housing stock in cold climates. Our findings suggest that heat pumps are not a feasible economic alternative for households currently using natural gas, unless governments offset energy cost premiums through public funding. Some of the policy discussion around heat pumps does not acknowledge this (U.S. Department of Energy, 2023; Rewiring America, 2021; Fathollahzadeh et al., 2022). Such an investment can be justified on the basis of equity and by internalizing the social cost of carbon, current estimates of which are ~$180 per ton CO2 (U.S. Environmental Protection Agency, 2022; Rennert et al., 2022).

Coupling heating electrification with retrofits in existing homes with natural gas heating can limit utility cost increases and reduce a key barrier to heat pump adoption. At the same time, our study shows that even after a visit from a home energy auditor, homeowners can be left without sufficient information to act. The reports they are provided could be more useful in supporting investment decisions by providing a marginal abatement curve specific to each house, where the payback period of each measure is plotted against the cumulative cost of all the recommended measures. The homeowner can decide the most they are willing to spend, and the curve would show them all the fastest-payback measures that can be implemented for that amount.

The impact of rate structures should be analyzed based on empirical data from the rate base. Time-of-use rate design for electricity determines the cost increase for switching to heat pumps. We estimate that one rate (D1.11) reduced the increase in bills by 10 % compared to the flat rate (D1), while the other (D1.2) further elevated the average cost increase by 56 %. Modeled results using ResStock show the opposite, where the D1.11 rate is usually no worse than the flat rate (see Figure B.7 for utility rate comparison). Using empirical energy use data in utility rate design to understand how proposed rates affect households across the income spectrum and across housing quality given future adoption of heat pumps could help mitigate energy insecurity and promote greater access to heat pump adoption among natural gas users.

While our focus on Michigan allows us to understand the cost dynamics for electrification in a cold climate with high prevalence of natural gas use, limitations of our study include the small sample size and the limited regional scope. Additionally, we were unable to incorporate homeowner attitudes regarding converting their natural gas heating systems to electric heat pump systems. Future work will investigate these perceptions, examining the factors that influence decision making for residential electrification and further examining potential barriers to equitable adoption of heat pumps across income.

Ethics statement

The University of Michigan's Institutional Review Board reviewed and approved this research based on informed consent by study participants.

CRediT authorship contribution statement

Claire McKenna: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Project administration, Methodology, Investigation, Formal analysis, Data curation, Conceptualization, Funding acquisition. **Carina Gronlund:** Writing – review & editing, Supervision, Conceptualization, Methodology, Visualization, Formal analysis, Project administration. **Parth Vaishnav:** Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Project administration, Methodology, Investigation, Formal analysis, Data curation, Conceptualization, Supervision, Funding acquisition.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

Claire McKenna reports financial support was provided by U.S. Department of Energy and University of Michigan. Parth Vaishnav reports financial support was provided by University of Michigan.

Data availability

Model inputs and aggregated data that support the findings of this study are available from the corresponding author upon reasonable request. Demographic information for participants and raw data is not available in accordance with the informed consent agreement signed by study participants.

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Supplementary materials

Supplementary material associated with this article can be found, in the online version, at doi:10.1016/j.resconrec.2024.107699.

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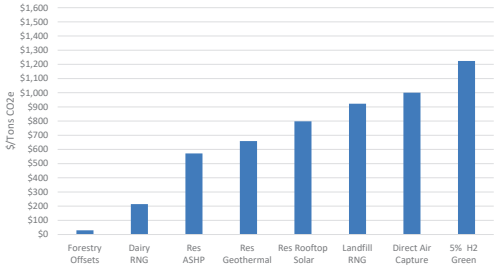
	Forestry Offsets	Dairy RNG	Res ASHP	Res Geothermal	Res Rooftop Solar	Landfill RNG	Direct Air Capture	5% H2 Green
$/Ton CO2e Abated	$30	$215	$572	$659	$798	$923	$1,000	$1,224

*Forestry offset ~ market rate
*Carbon capture, direct air capture based on literature as costs are not well understood in the industry
*Hybrid heating does not show a positive $/ton value
*Grey hydrogen does not show a positive $/ton value

Discount Rate	7.05%	
Inflation Rate	2.00%	
Base Year Data	2023	
Current Year	2024	
Delta	1	
Electric Rate residential (Dec 2024)	$0.1911	
Electric Rate C&I	$0.0849	
Average electric	$0.1433	
Gas Rate	$9.49	
Energy Loss	87	mmbtu/yr



*abatement cost methodology = For cost, use only cost needed to reduce the tonnage, do not include any BAU cost. Abatement is carbon footprint of fossil fuel less carbon footprint of clean fuel
*Emission are quanitified through a lifecycle approach
*"Marginal cost" represents a technology swap and therefore recognizing offset natural gas cost in economics - i.e. the cost of the technology itself incremental above natural gas
*"Annual cost" represents change in technology at existing asset end of life, not including offset cost for natural gas

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*Annual	Energy Usage	CI Score	Emissions (CO2e/yr)
Natural Gas (mmbtu)	87	79	7
Landfill RNG (mmbtu)	87	50	5
Electricity (KWh)	4,140,000,000		

	CE Load Serve - *As of 2021 IRP			Heat Pump	Marginal Abatement	Landfill Gas	Marginal Abatement
lbs/MWh	Grams / MJ	Tons/KWh					
1209							
1107							
1171							
1073	135	0.00049		2,016,275	-2,016,268	5	3
913	115	0.00041		1,716,216	-1,716,209	5	3
761	96	0.00035		1,431,004	-1,430,996	5	3
671	85	0.00030		1,261,260	-1,261,252	5	3
657	83	0.00030		1,234,930	-1,234,922	5	3
637	80	0.00029		1,197,925	-1,197,918	5	3
608	77	0.00028		1,143,311	-1,143,303	5	3
600	76	0.00027		1,126,810	-1,126,803	5	3
606	76	0.00028		1,139,684	-1,139,676	5	3
619	78	0.00028		1,163,176	-1,163,168	5	3
623	79	0.00028		1,171,013	-1,171,005	5	3
620	78	0.00028		1,164,829	-1,164,822	5	3
598	75	0.00027		1,123,089	-1,123,082	5	3
556	70	0.00025		1,044,099	-1,044,092	5	3
521	66	0.00024		979,336	-979,329	5	3
491	62	0.00022		923,482	-923,474	5	3
454	57	0.00021		853,701	-853,694	5	3
414	52	0.00019		777,342	-777,335	5	3
414	52	0.00019		777,342	-777,335	5	3
414	52	0.00019		777,342	-777,335	5	3
414	52	0.00019		777,342	-777,335	5	3
414	52	0.00019		777,342	-777,335	5	3
414	52	0.00019					
414	52	0.00019					
414	52	0.00019					

117	lbsCO2	1	Ton	0.05318182						
	mmbtu	2200	lbs							
	1209 LBs	453.59 grams	.000278 MWh	160.901074						
	MWh	1 LB	1 MJ							
117	lbsCO2	453.59	grams	0.000948	mmbtu	50.31039				
	mmbtu	1	Lb	1	MJ					
117	lbsCO2	1Ton	0.003412	mmbtu						
	mmbtu	2200lbs		1KWh						
		0.05318182								
	Natural Gas Fur	.01443 tons/mmbtu >								
	AC	.00049tons/KWh >								
	-300	gCO2e	1	MT	1	MJ	-0.316455696	MT CO2e		
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu		
	0	gCO2e	1	MT	1	MJ	0.0000000	MT CO2e		
	1	MJ	1000000	g	0.277778	KWh		KWh		
	10	gCO2e	1	MT	1	MJ	3.6E-05	MT CO2e		
	1	MJ	1000000	g	0.277778	KWh		KWh		
	10	gCO2e	1	MT	1	MJ	0.010548523	MT CO2e	5274.261603	
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu		

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Asset Life	20																				
Energy Usage (mmbtu)	87																				
Total tons eliminated	7																				
RNG %	24%																				
RNG ($/mmbtu)	$65.00																				
RNG + full service	$74.49																				
Total Supply	79	gCO2e	1	MT	1	MJ	0.08333333	MT CO2e		87	7.2816541										
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu													
										MCF	**Tons CO2e**										
Dairy RNG	-250	gCO2e	1	MT	1	MJ	-0.26371308	MT CO2e		21	-6										
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu													
Natural Gas	79	gCO2e	1	MT	1	MJ	0.08333333	MT CO2e		66	6										
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu													
Dairy RNG	$1,562																				
Natural Gas	$630																				
Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Initial Investment	$0																				
Natural Gas		$643	$656	$669	$682	$696	$710	$724	$738	$753	$768	$784	$799	$815	$832	$848	$865	$882	$900	$918	$936
RNG		$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562	$1,562
Total Cost		$2,205	$2,218	$2,231	$2,244	$2,258	$2,272	$2,286	$2,301	$2,315	$2,330	$2,346	$2,361	$2,377	$2,394	$2,410	$2,427	$2,445	$2,462	$2,480	$2,499
NPV of Total Costs	$24,372																				
NPV of RNG	$16,485																				
Displaced Natural gas		$203	$207	$211	$215	$220	$224	$229	$233	$238	$243	$247	$252	$257	$263	$268	$273	$279	$284	$290	$296
NPV of Total Costs	$2,491																				
Annual Tons of Abatement Reduced	7																				
Annual Cost	$2,073																				
$/mmbtu	$24																				
Marginal Annual Cost	$1,562																				
$/ton	$215																				

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Enerav Usage (mmbtu)	87																					
Tons lifecycle (tons)	7																					
RNG %	100%																					
RNG ($/mmbtu)	$30.00	*obtained from peer producer collaboration																				
RNG + full service	$39.49																					
Total Supply	79	gCO2e	1	MT	1	MJ	0.08333333	MT CO2e		87	7											
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu		MCF	Tons CO2e											
Landfill RNG	50	gCO2e	1	MT	1	MJ	0.05274262	MT CO2e		87	5											
	1	MJ	1000000	e	0.000948	mmbtu		mmbtu			3											
Landfill RNG	$3,451																					
Natural Gas	$829																					
Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
Initial Investment	$0																					
Natural Gas																						
RNG		$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	
Total Cost		$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	$3,451	
NPV of Total Costs	$36,414																					
Displaced Natural gas		$846	$863	$880	$898	$916	$934	$953	$972	$991	$1,011	$1,031	$1,052	$1,073	$1,094	$1,116	$1,138	$1,161	$1,184	$1,208	$1,232	
NPV of Total Costs	$10.377																					
Annual Tons of Abatement Reduced	3																					
Annual Cost	$2,467																					
$/mmbtu	$28																					
Marginal Annual Cost	$2,467																					
$/ton	$923																					

Electricity	117	gCO2e	1	MT	1	MJ	0.0004212	MT CO2e			
	1	MJ	1000000	g	0.277778	KWh		KWh			
	79	gCO2e	1	MT	1	MJ	0.08333333	MT CO2e			
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu			
	79	eCO2e	1	MT	1	MJ	1	mmbtu	0.00833333		
		MJ	1000000	g	0.000948	mmbtu	10	therms			

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Air Source Heat Pump

Life (Years)	15.00													
		1 kWh = 0.003412 MMBTU												
HSPF (10 energy star)	10=BTUs/WH													
BTU loss	87,379,849		79	gCO2e	1	MT	1	MJ	0.083333	MT CO2e		87	7	
Kilowatt hours required	8,738		1	MJ	1000000	g	0.000948	mmbtu		mmbtu				
SEER (15 energy star)	15=output (btu)/input (wh)													
BTU gain	903,030													
Kilowatt hours required	60													

	Data	**Source**
CAPEX Replacement	$5,000	UofM heat pump study
Current Year Capex	$5,100	
Annual maintenance	$20	2023 EIA Study
Current Year maintenance	$20	
Heating energy required	8,738	KWh
Cooling energy required	60	KWh
Cost of energy	$1,681	
Total Annual O&M	$1,702	

Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Initial Investment	$5,100															
O&M		$1,736	$1,770	$1,806	$1,842	$1,879	$1,916	$1,955	$1,994	$2,034	$2,074	$2,116	$2,158	$2,201	$2,245	$2,290
Rebate (30% up to $2000)		-$1,530														
Present Value of Costs	$5,100	$206	$1,770	$1,806	$1,842	$1,879	$1,916	$1,955	$1,994	$2,034	$2,074	$2,116	$2,158	$2,201	$2,245	$2,290
NPV of Total Costs	$21,393															
	37.39	3.819614	3.87557	3.954211	4.070275	4.105342	4.077983	4.028059	4.011404	4.024544	4.11325	4.281116	4.418748	4.537448	4.685744	4.848019
Annual Tons CO2 Reduced	4.12															
Annual Cost	$2,356															
$/mmbtu	$26.69															
Marginal Annual Cost	$2,356															
$/Ton Abated	$572															

2.215081
2.852757
3.45888
3.819614
3.87557
3.954211
4.070275
4.105342
4.077983
4.028059
4.011404
4.024544
4.11325
4.281116
4.418748
4.537448
4.685744
4.848019
4.848019
4.848019
4.848019
4.848019

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Lifetime	20																				
Energy Usage (mmbtu)	87	mmbtu	1	KWh	1	MWh	26	MWh	0.18	$	1000	KWh	$ 4,609.72								
Energy Usage (MWh)	26		0.003412	mmbtu	1000	KWh				KWh	1	MWh									
Energy Usage (KWh)	25,610																				
Tons lifecycle (tons)	7												1664.621981								
LCOE ($/MWh)	$142.00	https://www.energy.gov/eere/solar/solar-photovoltaic-system							$												
									Mwh		1	Mwh	$0.142								
											1000	KWh									
Total Supply	79	gCO2e	1	MT	1	MJ	0.08333333	MT CO2e	87	7											
	1	MJ	1000000	g	0.000948	mmbtu		mmbtu													
Cost	$5,811																				
Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Initial Investment	$0																				
Solar		$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811	$5,811
NPV of Total Costs	$61,321																				
Annual Tons of Abatement Reduced	7																				
Annual Cost	$5,811																				
$/mmbtu	$67																				
Marginal Annual Cost	$5,811																				
$/ton	$798																				

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Geothermal Herat Pump		
Life (Years)	25.00	
HSPF (13 energy star)	13=BTUs/WH	
BTU loss	87,379,849	4.248
Kilowatt hours required	6,722	
SEER (25 energy star)	25=output (btu)/input (wh)	
BTU gain	903,030	
Kilowatt hours required	36	

	Data	**Source**
CAPEX Replacement	$19,650	2023 EIA Study
Current Year Capex	$20,043	
Annual maintenance	$75	
Current Year maintenance	$77	
Heating energy required	6,722	
Cooling energy required	36	
Cost of energy	$1,291	
Total Annual O&M	$1,368	

Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Initial Investment	$20,043																									
O&M		$1,395	$1,423	$1,452	$1,481	$1,510	$1,540	$1,571	$1,603	$1,635	$1,667	$1,701	$1,735	$1,770	$1,805	$1,841	$1,878	$1,915	$1,954	$1,993	$2,033	$2,073	$2,115	$2,157	$2,200	$2,244
IRA (30% ITC)		-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241	-$241
Present Value of Costs	$20,043	$1,155	$1,183	$1,211	$1,240	$1,270	$1,300	$1,331	$1,362	$1,394	$1,427	$1,460	$1,494	$1,529	$1,564	$1,600	$1,637	$1,675	$1,713	$1,752	$1,792	$1,833	$1,874	$1,917	$1,960	$2,004
NPV of Total Costs	$36,627																									
Annual Tons of Abatement Reduced	55.60	4.441269	4.484246	4.544648	4.633794	4.660728	4.639715	4.601369	4.588577	4.59867	4.666802	4.795736	4.901447	4.992618	5.106519	5.231158	5.231158	5.231158	5.231158	5.231158	5.231158	5.231158	5.231158	5.231158	5.231158	5.231158
	4.79																									
Annual Cost	$3,157																									
$/mmbtu	$35.76																									
Marginal Annual Cost	$3,157																									
$/Ton Abated	$659																									

3.20887
3.698652
4.164198
4.441269
4.484246
4.544648
4.633794
4.660728
4.639715
4.601369
4.588577
4.59867
4.666802
4.795736
4.901447
4.992618
5.106519
5.231158
5.231158
5.231158
5.231158
5.231158

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Electric resistance

Life (Years)	15.00						
		1 kWh = 0.003412 MMBTU					
BTU loss	87,379,849	btu	1	mmbtu	1	kwh	25609.57
Efficiency	100%						
Kilowatt hours required	25,610		1000000	btu	0.003412	mmbtu	

	Data	Source
CAPEX Replacement	$1,190	2023 EIA Study
Current Year Capex	$1,214	
Annual maintenance	$0	2023 EIA Study
Current Year maintenance	$0	
Heating energy required	25,610	KWh
Cooling energy required	0	KWh
Cost of energy	$4,894	
Total Annual O&M	$4,894	

Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Initial Investment	$1,214															
O&M		$4,992	$5,092	$5,194	$5,297	$5,403	$5,511	$5,622	$5,734	$5,849	$5,966	$6,085	$6,207	$6,331	$6,458	$6,587
Present Value of Costs	$1,214	$4,663	$4,443	$4,234	$4,034	$3,844	$3,662	$3,489	$3,325	$3,168	$3,019	$2,876	$2,740	$2,611	$2,488	$2,371
NPV of Total Costs	$52,180															
Displaced Natural gas	$0	$846	$863	$880	$898	$916	$934	$953	$972	$991	$1,011	$1,031	$1,052	$1,073	$1,094	$1,116
NPV of Displaced NG Costs	$8,636															
Tons of Abatement Reduced		4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393	4.26393

Annual Cost	$5,747
$/mmbtu	$65.77
Marginal Annual Cost	$4,796
$/Ton Abated	$1,125

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*All values based on ICNI study

HHV_H2	0.1342286	mmbtu Kg H2		61,013	btu pound	2.2	pounds Kg	1 1000000	mmbtu btu	
Total throughput	200,000,000	mmbtu								
Blend (%)	5.00%									
Energy requirement / yr (mmbtu)	10,000,000	mmbtu								
H2 Production Required	0.134	mmbtu Kg H2								
Kg / yr	74,499,771	Kg H2								
Kg / day	204,109	Kg H2								
Electrolyser										
Stack Efficiency	55	kWh/kg								
Input Power	467,750	kW								
Capex Rate	1,872	$/Kw								
Capital Cost	875,627,449									
Water										
Input power	756	Kw								
Usage	3,147	tons/hour								
Capex Rate	4,583	$/Kw								
Capital Cost	3,464,748									
Compression										
Input Power	1,340	Kw								
Capex Rate	13,328	$/Kw								
Capital Cost	17,859,520									
Balance of Plant										
Input Power	2,913	kW								
Capex Rate	16,821	$/Kw								
Capital Cost	49,000,000									
Additional Capital	44,000,000									
Total Capital	989,951,717									
Solar Cost of Energy	50	$/MWh								
Total input power requird	473	Mw								
Capacity Factor	20%									
Capacity Required	2,364	Mw								
MWh required per year	20,706,831	MWh								

Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Initial Investment	$989,951,717																				
O&M		$1,035,341,565	$1,056,048,396	$1,077,169,364	$1,098,712,752	$1,120,687,007	$1,143,100,747	$1,165,962,762	$1,189,282,017	$1,213,067,657	$1,237,329,011	$1,262,075,591	$1,287,317,103	$1,313,063,445	$1,339,324,713	$1,366,111,208	$1,393,433,432	$1,421,302,101	$1,449,728,143	$1,478,722,705	$1,508,297,160
IRA ($/KG)		-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314	-$223,499,314
Total Cost	$989,951,717	$811,842,251	$832,549,083	$853,670,051	$875,213,438	$897,187,693	$919,601,433	$942,463,448	$965,782,703	$989,568,344	$1,013,829,697	$1,038,576,277	$1,063,817,789	$1,089,564,131	$1,115,825,400	$1,142,611,894	$1,169,934,118	$1,197,802,787	$1,226,228,829	$1,255,223,392	$1,284,797,846
NPV of Total Costs	$10,587,355,580																				
Displaced Natural Gas		$96,798,000	$98,733,960	$100,708,639	$102,722,812	$104,777,268	$106,872,814	$109,010,270	$111,190,475	$113,414,285	$115,682,570	$117,996,222	$120,356,146	$122,763,269	$125,218,535	$127,722,905	$130,277,363	$132,882,911	$135,540,569	$138,251,380	$141,016,408
NPV of Total Costs	$1,187,594,852																				
Energy (mmbtu)		10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000
Hydrogen (Kg)		74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771
Abatement		727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848	727,848
Annual Cost	$1,003,258,469																				
$/kg	$13.47																				
$/mmbtu	$100.33																				
Marginal Annual Cost	$890,721,907																				
$/Ton Abated	$1,224																				

10	eCO2e	1	MT	1	MJ	0.010548523	MT CO2e	105.485	
1	MJ	1000000	g	0.000948	mmbtu		mmbtu		
79	gCO2e	1	MT	1	MJ	0.083333333	MT CO2e	833,333	
1	MJ	1000000	g	0.000948	mmbtu		mmbtu		
								727,848	

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**All values based on LCRI study*

HHV_H2	0.1342286	mmbtu Kg H2		61,013	btu pound	2.2	pounds Kg	1 1000000	mmbtu btu	
Total throughput	200,000,000	mmbtu								
Blend (%)	5.00%									
Energy requirement / yr (mmbtu)	10,000,000	mmbtu								
H2 Production Required	0.134	mmbtu Kg H2								
Kg / yr	74,499,771	Kg H2								
Kg / day	204,109	Kg H2								
Electrolyzer										
Stack Efficiency	55	kWh/kg								
Input Power	467,750	kW								
Capex Rate	1,872	$/Kw								
Capital Cost	875,627,449									
Water										
Input power	756	Kw								
Usage	3,147	tons/hour								
Capex Rate	4,583	$/Kw								
Capital Cost	3,464,748									
Compression										
Input Power	1,340	Kw								
Capex Rate	13,338	$/Kw								
Capital Cost	17,859,520									
Balance of Plant										
Input Power	2,913	kW								
Capex Rate	16,821	$/Kw								
Capital Cost	49,000,000									
Additional Capital	44,000,000									
Total Capital	945,951,717									

Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Initial Investment	$945,951,717																				
O&M		$791,415,092	$807,243,394	$823,388,262	$839,856,027	$856,653,148	$873,786,211	$891,261,935	$909,087,174	$927,268,917	$945,814,296	$964,730,582	$984,025,193	$1,003,705,697	$1,023,779,811	$1,044,255,407	$1,065,140,515	$1,086,443,326	$1,108,172,192	$1,130,335,636	$1,152,942,349
Total Cost	$945,951,717	$791,415,092	$807,243,394	$823,388,262	$839,856,027	$856,653,148	$873,786,211	$891,261,935	$909,087,174	$927,268,917	$945,814,296	$964,730,582	$984,025,193	$1,003,705,697	$1,023,779,811	$1,044,255,407	$1,065,140,515	$1,086,443,326	$1,108,172,192	$1,130,335,636	$1,152,942,349
NPV of Total Costs	$9,953,910,806																				
Displaced Natural Gas		$96,798,000	$98,733,960	$100,708,639	$102,722,812	$104,777,268	$106,872,814	$109,010,270	$111,190,475	$113,414,285	$115,682,570	$117,996,222	$120,356,146	$122,763,269	$125,218,535	$127,722,905	$130,277,363	$132,882,911	$135,540,569	$138,251,380	$141,016,408
NPV of Total Costs	$1,187,594,852																				
Energy (mmbtu)		10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000
Hydrogen (Kg)		74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771	74,499,771
Abatement		527,426	527,426	527,426	527,426	527,426	527,426	527,426	527,426	527,426	527,426	527,426	527,426	527,426	527,426	527,426	527,426	527,426	527,426	527,426	527,426
Annual Cost	$943,233,203																				
$/kg	$12.66																				
$/mmbtu	$94.32																				
Marginal Annual Cost	$830,696,842																				
$/Ton Abated	$1.575																				

	10 1	#CO2e MJ	1 1000000	MT g	1 0.000948	MJ mmbtu	0.010548523	MT CO2e mmbtu	105.485
	50 1	gCO2e MJ	1 1000000	MT g	1 0.000948	MJ mmbtu	0.052742616	MT CO2e mmbtu	527,426
									421,941

	CE Load Serve - *As of 2021 IRP*				
lbs/MWh	Grams / MJ	Tons/KWh	H2 Blend	Natural Gas	
1309					
1107					
1171					
1073	135	0.00049	#REF!	527,426	#REF!
913	115	0.00041	#REF!	527,426	#REF!
761	96	0.00035	#REF!	527,426	#REF!
671	85	0.00030	#REF!	527,426	#REF!
657	83	0.00030	#REF!	527,426	#REF!
637	80	0.00029	#REF!	527,426	#REF!
608	77	0.00028	#REF!	527,426	#REF!
600	76	0.00027	#REF!	527,426	#REF!
606	76	0.00028	#REF!	527,426	#REF!
619	78	0.00028	#REF!	527,426	#REF!
623	79	0.00028	#REF!	527,426	#REF!
620	78	0.00028	#REF!	527,426	#REF!
598	75	0.00027	#REF!	527,426	#REF!
556	70	0.00025	#REF!	527,426	#REF!
521	66	0.00024	#REF!	527,426	#REF!
491	62	0.00022	#REF!	527,426	#REF!
454	57	0.00021	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!
414	52	0.00019	#REF!	527,426	#REF!

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Hybrid Heat Pump				
Life (Years)	20.00			
	Percent of time used			
Furnace	41.67%	Every month temp is below 45 degrees		
Heat Pump	58.33%	Every month average temp is above 45 degrees		
		Furnace	**Heat Pump**	
BTU loss	87,379,849	42%	58%	
BTU gain	903,030	0%	100%	
Total Energy Loss	88,282,879			
Furnace				
Energy required (btu)	36,699,537			
Efficiency	95%			
mmbtu Required	39			
Heat Pump				
Energy Required (btu)	50,680,313	50.680313	2.6911246	
HSPF	8.5			
Kilowatt hours required	5,962			
SEER (15 energy star)	15=output (btu)/input (wh)			
SEER	15			
BTU gain	903,030			
Kilowatt hours required	60			
	Data	**Source**		
Heat Pump Capex	$6,940	https://www.fixr.com/costs/hybrid-heat-pump		
AC Capex	$3,750			
Current Year Capex	$10,904			
Annual maintenance	$40	2023 EIA Study		
Current Year maintenance	$41			
Cost of energy	$1,518			
Total Annual O&M	$1,558			

Total Costs	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Initial Investment	$10,904																				
O&M		$1,589	$1,621	$1,654	$1,687	$1,721	$1,755	$1,790	$1,826	$1,862	$1,900	$1,938	$1,976	$2,016	$2,056	$2,097	$2,139	$2,182	$2,226	$2,270	$2,316
Rebate (30% up to $2000)		-$900																			
Present Value of Costs	$10,904	$644	$1,415	$1,348	$1,284	$1,224	$1,166	$1,111	$1,059	$1,009	$961	$916	$873	$831	$792	$755	$719	$685	$653	$622	$593
NPV of Total Costs	$29,564																				
Displaced Natural gas	$0	$846	$863	$880	$898	$916	$934	$953	$972	$991	$1,011	$1,031	$1,052	$1,073	$1,094	$1,116	$1,138	$1,161	$1,184	$1,208	$1,232
NPV of Displaced NG Costs	$10,377																				
Tons of Abatement Reduced		2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47
Annual Cost	$2,802																				
$/mmbtu	$31.73																				
Marginal Annual Cost	$1,818																				
$/Ton Abated	$736																				

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Energy Star Formulas

COP — The COP is a measure of the amount of power input to a system compared to the amount of power output by that system. The COP is therefore a measurement of efficiency; the higher the number, the more efficient the system is. The COP is dimensionless because the input power and output power are measured in Watt. The COP is also an instantaneous measurement in that the units are power which can be measured at one point in time.

$$COP = \frac{\text{power output}}{\text{power input}} \quad \text{(Eq 1)}$$

SEER — the SEER is the ratio of output coolinv energy (in BTU) to electrical input energy (in Watt-hour). However the SEER is a representative measurement of how the system behaves over a season where the outdoor temperature varies

$$SEER = \frac{\text{output cooling energy in BTU over a season}}{\text{input electrical energy in Wh during the same season}} \quad \text{(Eq 9)}$$

EER — How do you convert SEER to EER?
Typical EER for residential central cooling units = 0.875 × SEER. SEER is a higher value than EER for the same equipment.

COP — HSPF 10 = 2.93 COP

10	HSPF	3.6 COP	12.28668942
2.93	COP		

HSPF — Like SEER, this is a measurement of the efficiency of a system and the units are the same (BTU/h divided by Watt). However, this measures the efficiency of the system in heating mode, not cooling mode. Therefore it applies only to heat pumps or reversible air conditioning units and not to units that only cool a space.
The HSPF's formula:

$$\text{HSPF (heating seasonal performance factor)} = \frac{\text{Total heating produced in Btu (including electric heat)}}{\text{Watt-hours of electricity used over the same season}}$$

KW/Ton — The efficiencies of base industrial air conditioner systems, especially chillers, are given in kW/ton to specify the amount of electrical power that is required for a certain power of cooling. In this case, a smaller value represents a more efficient system.

$$COP = \frac{\text{power output in } \Psi}{\text{power input in } \Psi} = \frac{3.517}{\text{kW/ton}} \quad \text{(Eq 17)}$$

80% annual fuel utilization efficiency (AFUE) furnace (the current federal minimum efficiency standard)5
95% AFUE furnace (the most common high-efficiency furnace and the ENERGY STAR® level for the North)
97% AFUE furnace (the ENERGY STAR Most Efficient level)
Geothermal Energy star DGX - EER 16, COP 3.6
8.2 heating seasonal performance factor (HSPF) heat pump (current federal standard for split systems)
8.5 HSPF heat pump (the ENERGY STAR level)6
10.3 HSPF heat pump (the ENERGY STAR Most Efficient level)7
A cold-climate electric heat pump. This is a very preliminary analysis based on one field test that found a seasonal 2.8 coefficient of performance (COP) in Connecticut. More products and data are needed.

Other Reference Data

Furnace reference data	https://www.pickhvac.com/electric-furnaces/
Electric furnace Cost	https://homeguides.sfgate.com/much-electric-furnace-cost-102516.html#:~:text=Each%20unit%20overall%20is%2435%2C769,20per%24142%2C788%20using%20an%20electric%20furnace.
AC and Heat Pump model data sheets	https://www.energystar.gov/products/most_efficient/central_air_conditioners_and_air_source_heat_pumps
Residential energy calculator	https://www.energyhub.com/blog/electricity-prices/
Energy use to CO2e calculator	https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

Formulas

Conductive Required Heating Energy	mmbtu/day	(Area*degree days*.24 hours*U Value)/1000000
Infiltration Required Heating Energy	mmbtu/day	(Space vol*Delta Temp*air changes/hr*heat factor* 24 hours)/1000000 The air infiltration heat loss is uncontrolled heat loss through joints in the construction and cracks around doors and windows. This figure is affected by wind and pressure differentials between the outside and interior of the home which causes air to move inside the home, thereby producing heat loss as that air escapes the room. The heat capacity of air at sea level is, on average, 0.018 Btu per cu. ft. per degree F.

Model Assumptions

Mock home size (SF) (50'x31')	1707.5	https://fred.stlouisfed.org/series/MEDSQUFEE08020
Flint/Saginaw/Midland	1500	
Lansing	1660	
Grand Rapids	1966	
Jackson	1704	
Contributing insulation surfaces	Exterior walls; attic; single floor	
R-Values	Energy Star	https://www.lm.com/en/homeowner-insulation/homeowner-faq/what-r-value-do-i-need-/

	R-Value	Weight Average R-Value	Surface Area
Walls	15	4.1	1280
Attic	45	16.4	1707.5
Floors	25	9.1	1707.5
Weighted Average Home R-Value/Total Area		29.5	4685
U-Value		0.034	

Home volume	Cubic feet	13660
Heat capacity factor	BTU/cubic foot	0.018 The heat capacity of air at sea level is, on average, 0.018 Btu per cu. ft. per degree F
Air Change	Cubic feet/hr	1.5

Weather Assumptions

Climate Zone 4 & 5		https://inspectapedia.com/heat/Heating-Cooling-Climate-Zone-BTU-Requirements.php#HeatingBTUs
Heating Base Temp		68
Cooling Base Temp		72
Average Temps		https://en.climate-data.org/north-america/united-states-of-america/michigan/detroit-330/

Heating Degree Days	Days/month	Average Temp (Detroit)	Heating Degree Days	Cooling Degree Days
January Average Temp	31	24.4	1351.6	0
February Average Temp	28	26.1	1173.2	0
March Average Temp	31	35	1023	0
April Average Temp	30	47.6	612	0
May Average Temp	31	59.9	251.1	0
June Average Temp	30	69.9	0	0
July Average Temp	31	74	0	62
August Average Temp	31	72.3	0	9.3
Sept Average Temp	30	65.8	66	0
October Average Temp	31	53.3	455.7	0
November Average Temp	30	41.3	801	0
December Average Temp	31	30.4	1165.6	0

Energy Loss * Residential

Heating Energy Loss		Cooling Energy Loss	
Conductive Energy Loss (mmbtu)	Infiltration (mmbtu)	Conductive Energy Gain (mmbtu)	Infiltration Gain (mmbtu)
5.154	11.96	0.000	0.00
4.474	10.38	0.000	0.00
3.901	9.06	0.000	0.00
2.334	5.42	0.000	0.00
0.958	2.22	0.000	0.00
0.000	0.00	0.000	0.00
0.000	0.00	0.236	0.55
0.000	0.00	0.035	0.08
0.252	0.58	0.000	0.00
1.738	4.03	0.000	0.00
3.055	7.09	0.000	0.00
4.445	10.32	0.000	0.00
26	61	0.3	0.6
Total loss (mmbtu)	87.38	Total gain (mmbtu)	0.9

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Full length article

Heating with justice: Barriers and solutions to a just energy transition in cold climates

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ABSTRACT

Residential heat pumps could reduce greenhouse gas emissions, but increase energy burdens, the proportion of income households spend on utility bills. We analyze utility bills, thermostat settings and energy burdens for a sample of 51 households in Michigan, half below median income. We recruit a contractor to conduct energy assessments of these households and provide them with energy retrofit recommendations, including estimated costs and savings. We find that low-income households choose similar temperature setpoints to higher-income households, but live in less efficient homes. Below-median income households, which today experience a median energy burden of 6 %, would see it rise to 10 % if they shifted to electric heat pumps from natural gas. Weatherization could offset this increase, bringing burdens down to pre-electrification levels. However, median payback is 24 years, making retrofits infeasible for the poorest. Our results are indicative of an energy poverty trap that could hinder an equitable energy transition.

Spotlights

- Converting fossil-fuel based home heating to electric could reduce pollution but make bills less affordable.
- Switching to electric heating results in low-to-moderate income households paying a high percentage of income on energy.
- Retrofitting homes could make electric heating more affordable but it is expensive and therefore infeasible.
- High-cost energy efficiency home retrofits could hinder an equitable energy transition.
- Future work will investigate homeowner attitudes regarding electrifying their homes and barriers to equitable transition.

1. Introduction

In recent years, US state policy (Climate Leadership and Community Protection Act 2020; An Act Creating 2022; Climate Commitment Act 2022)) has signaled a commitment to reducing greenhouse gas emissions by transitioning home heating from fossil fuels to electricity. U.S. federal policy has sought to use subsidies to lower the upfront cost of heat pump adoption (Inflation Reduction Act, H.R. 5376). Electrification has been projected to increase annual utility cost for households in more than half of US states (Vaishnav and Fatimah 2020; Deetjen et al., 2021), with the worst effects in cold climates (Walker et al., 2022). Rising energy costs could have a large impact on households across the income spectrum.

1.1. Literature review

Higher utility bills could increase the economic and physical hardships in households already experiencing energy insecurity. A quarter of American households spend a high proportion (>6 %) of their income on utilities, defined as energy burden (Drehobl et al., 2020). High energy burden is associated with poor health outcomes (Reames, 2016), and households with certain vulnerabilities, such as older adults, choose uncomfortable and sometimes unsafe indoor temperatures to reduce bills (Cong et al., 2022). Lewis et al. center deteriorated housing conditions concentrated in racially segregated neighborhoods in their discussion of energy insecurity, which encompasses financial, behavioral and physical hardships related to home energy use (Lewis et al., 2020).

Households with lower energy burdens are not entirely precluded from the effects of higher ongoing costs associated with heating electrification because these costs are associated with building

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characteristics that are prevalent across the US housing stock. Old homes heated by natural gas have been shown to result in the greatest operational costs for heating with a heat pump (Vaishnav and Fatimah, 2020). 64.5 million American homes use natural gas for heating and 57 % of them were built before energy codes were implemented in the US (U.S. Energy Information Administration, 2023). Knowledge of household demographics, housing characteristics, and occupant behavior are essential to understanding the barriers to equitable access to heat pumps and a just distribution of harms and benefits associated with policy that facilitates the clean heating transition.

Current research about residential energy equity includes only one or two of these critical components. Studies that quantify the link between racial disparities in energy use and housing quality (Goldstein et al., 2022; Bednar et al., 2017), and demonstrate that households of color are more likely to have trouble paying their bills (Graff et al., 2021) do not take into account behavior. Studies that evaluate specific retrofit opportunities and quantify their the savings potential by employing national scale modeling do not address behavior impacts associated with those changes (Bradshaw et al., 2014; Wilson et al., 2019). Likewise, studies that examine the economics of heat pump adoption for low income households, whether in observed system performance (Ceglia et al., 2022; Flower et al., 2020; Calver et al., 2022; Pastore et al., 2022; Liu et al., 2018) or simulations (Donaldson and Lord, 2018; Barrella et al., 2020; Liu et al., 2020; Abbasi et al., 2022; Savage et al., 2022) focus on housing and heat pump technology characteristics without an empirical analysis of occupant behavior and preferences for heating and cooling.

Several recent studies examining the energy savings potential of residential retrofits in the European context point to the importance of incorporating household behavior in home energy assessments (Palma et al., 2022; Barrella et al., 2020; Koasidis et al., 2022; Domínguez-Amarillo et al., 2020). The literature addressing the effect of energy consumption behavior on the cost effectiveness of energy retrofits in the US commonly uses economics theory and analysis. Gillingham and Palmer (2014) conducted a literature review of explanations for limited uptake of home energy efficiency including that flawed decision making could reduce the utility of energy efficiency to customers. Three studies followed that examined this question using home energy efficiency project data from the US Department of Energy Weatherization Assistance Program (WAP). Zivin and Novan (2016) measure the treatment effect of retrofits on energy use of 275 households and provide evidence that electricity savings due to WAP are overstated. Allcott and Greenstone (2017) and Fowlie, Greenstone and Wolfram (2018) use large samples of primary empirical data to estimate the benefits of providing energy efficiency services to low-income homes. Though these studies consider behavioral explanations for under performance of projects compared to engineering estimates, they do not provide detail on the housing conditions prior to intervention or the specific work performed. See Table C.7 for a comparison of this paper's contributions to those of the literature.

Other large empirical studies that address impacts of high utility costs on vulnerable households similarly do not provide data on the housing characteristics of the populations they examine (Cong et al., 2022; White and Sintov, 2020), and therefore do not address why these impacts occur. Although Booth and Choudhary (2013) estimate the rebound effect, identify specific upgrade parameters, and focus on public housing in their assessment of uncertainty in retrofit performance (Booth and Choudhary, 2013), they do not address the transition in heating technology. Recent research has signaled the potential for heat pumps to contribute to residential sector clean heating transition where countries push for climate action and fossil fuels remain the predominant fuel source (Fitó et al., 2021; Thomaßen et al., 2021; Besagni et al., 2020).

1.2. Research gaps

There remains a gap in quantifying the impacts of residential heating electrification across income and in examining interventions specific to both housing quality and energy consumption behavior. Previous studies that have taken this form to assess the reasons for disproportionate impacts of energy cost across income (Cong et al., 2022; Jones et al., 2023) only examine it in the context of air conditioning, not heating. To bridge this gap, this study aims to disentangle the sources of inequality embedded in the economic impact of heat pump adoption and assess fixes available for real homes. The present work has three main contributions. First, we provide evidence that energy burden impacts across income are associated with housing quality rather than behavior. Second, we compare economic impact of heating fuel transition across income groups. Third, we test the idea that there is a way to mitigate the utility cost premium for heat pumps.

We conduct a year-long field study of 51 homes in Southeast Michigan, during which we perform a comprehensive energy audit of each home to observe envelope and HVAC system characteristics, including thermal imaging to identify temperature gradients indicative of air leakage and poor insulation, and blower door testing to measure air infiltration rate, as well an examination of the on-label efficiency of all appliances. We gather metered daily gas and hourly electric consumption data over the study period and collect energy assessment contractor recommendations for energy efficiency retrofits for each home. Our approach to examining residential energy equity is novel because we compare results derived from observed data with simulations derived from statistical sampling of large public data sources (Wilson et al., 2022).

Following this introduction, we present the methods, then results, then we will discuss the findings and conclude. We present our findings in five parts. First, we examine the existing conditions of the homes in the study and compare them across income, including key housing characteristics and indoor temperature preferences. Next, we quantify the impact that replacing natural gas heating with heat pumps would have on household energy burden. We then examine the sensitivity of time of use utility rates on the annual energy bill impact of fuel switching. Following that, we quantify the cost savings potential of energy efficiency envelope improvements and compare it to the utility bill impact. Finally, we explore energy efficiency retrofit recommendations provided to participants during home energy audits and assess the feasibility of these improvements to mitigate the ongoing cost impact of heating electrification on the sample.

2. Methods

This study uses observed household energy use and indoor temperature data along with a reduced complexity air source heat pump coefficient-of-performance model to determine energy cost and energy burden impacts of switching to a heat pump. We gather energy retrofit recommendations and estimate upfront costs, energy cost savings, and payback from a contractor who conducted a detailed energy audit for each home. We then quantify annual utility bill impacts for fuel switching and energy retrofits using a building energy model that provides detailed sub-hourly simulations a large sample of archetypal homes that are representative of the study region and compare them to our findings for the sample.[1]

[1] See Data Availability statement for more information on how to access data that can be made available under the Institutional Review Board guidelines for human subjects research. See Supplemental Methods for additional detail on justification for model and calculation assumptions and Supplemental Figure, Tables, and Notes for detail on participant demographics, supporting findings, and literature review.

2.1. Participants

As described below, we recruited 51 participants from Wayne and Washtenaw Counties in Michigan, which encompass the Detroit and Ann Arbor metro areas. We chose Southeast Michigan for three factors that make this study applicable to global contexts including the Midwest, New England, and the Mountain West regions of the US; Northern Europe; and the United Kingdom: cold climate, predominance of natural gas for heating, and older homes.

Participant recruitment included three steps. First, we circulated an expression of interest form through local media, university email lists, and local environmental and energy justice community groups that drew more than 1300 responses. Second, we asked these respondents to complete a demographic survey to assess the presence of key factors associated with energy insecurity: race, income, disability, children, and health vulnerability (Drehobl et al., 2020; Reames, 2016; Hernández, 2016). We received 883 responses to the demographic questionnaire. Third, we identified a random sample stratified using survey answers to ensure representation across four key, binary, classes of vulnerability: has a disability, has at least one child at home, foregoes paying energy bills at least once a year, controls heating or cooling for a vulnerable occupant. These four classes correspond to 16 combinations, and we had respondents who corresponded to only 10 of them.

Next, we identified 418 survey respondents living in single family homes. We then classified the respondents into 10 categories representing the unique combinations of the key categories listed above. We calculated how many households we would need to invite to have an equal number across these categories and randomly selected that many households from each group. Where the quantity of respondents in a category was not great enough to provide an equal weighting, we invited all the respondents in the category. Ultimately, we compiled a list of 90 potential participants to whom we sent invites to join the study. Our recruitment rate was 58 %. Demographic questions and descriptive statistics can be found in Note D.3 and Table C.1. 90 respondents were asked to join the study. Demographic questions and descriptive statistics can be found in Note D.3 and Table C.1.

All households in the sample live in single family homes. 50 of the 51 households are homeowners; 1 is a renter. All homes use natural gas for heating with the exception of 1, which uses propane. The sample includes a diversity of housing vintage (i.e. common building practices) from every decade since 1900: 9 homes were built before 1940, 17 homes were built between 1940 and 1960, 12 built between 1961 and 1980, 6 built between 1981 and 2000, and 7 built after 2000.

The study sample is representative of the populations of the two counties of Southeast Michigan along two key characteristics. (1) Income: the median income (in 2022 dollars) is $57,223 for Wayne County and $84,245 for Washtenaw County (U.S. Census, 2024). The sample includes 11 households reported earning annual income <$25k, 18 earning $25–50k, 9 earning $50–75k and 13 earning >$75k. (2) Race: 54.6 % white, 38.3 % Black, and 7.1 % all other races in Wayne County and 73.9 % white, 12.4 % Black, and 13.7 % all other races in Washtenaw County (U.S. Census, 2024). The sample includes 29 % Black ($n = 15$), 45 % white ($n = 23$) and 25 % ($n = 13$) all other races, including one participant who prefers not to answer.

Households were provided $100 compensation.

2.2. Data collection

We obtained one year of utility data for each household, including hourly metered electricity use and daily metered gas use where available. We conducted one visit to each home, during which we installed a smart thermostat where the heating and cooling system could accommodate the product (Ecobee 3 lite) ($n = 40$). For homes that could not receive the smart thermostat, we set up a wi-fi connected thermo-hygrometer (Govee H5179). Both devices record data at 15-minute intervals. An accredited energy audit contractor accompanied the research team and performed an ASHRAE Level 2 energy audit at each home.

Participants provided income ranges, so we estimate energy burden based on the arithmetic midpoint, i.e., if a participant reports their income to $25k-50k, the energy cost burden for that household was calculated at the proportion of their actual annual utility bills to $37.5k. We did not apply an equivalence scale to energy expenditure and income because we observed occupancy in some homes to which the published equivalence scales would not readily apply, for example, households with adult children that may live at home for periods of time varying duration and frequency throughout the year. See Supplementary Methods for detail on energy burden calculation.

2.3. Housing quality analysis

To assess participant behavior, we estimate indoor temperature setpoints in two ways. First, we estimate the heating inflection temperature (HIT) (ambient temperature at which a household begins heating) for each home using a splitwise regression of metered daily gas use on hourly average ambient air temperature (obtained from NOAA Local Climatological Data (LCD) for the data collection period). Second, we evaluate the observed heating and cooling setpoints and the observed indoor temperature for the heating and cooling season for a subgroup that received a smart thermostat ($n = 40$). We calculate cooling and heating season means for setpoint temperature as well as the standard deviation for setpoint and indoor temperature using this interval data.

2.4. Heat pump cost analysis

Our energy cost analysis for switching to all-electric heat pumps from natural gas-based heating consists of three steps. See Appendix A for detailed calculation methodology and model specifications.

- *Heat load calculation. Existing furnace gas use.* To determine heating natural gas use, we first estimated the inflection point for temperature dependent gas use using a split-wise regression of heating degree hours (a measure of the intensity of the space heating needed for a given time and place) on hourly total gas use. We assumed that the slope of the piecewise linear function (found with the segmented() function in R) past this inflection point indicates heating related natural gas usage. From that, we derived the slope which is the natural gas usage per heating degree hour. We then obtained the amount of gas used during each hourly time step for heating by multiplying the slope by the difference between the outside ambient air temperature departure from the indoor heating setpoint gathered during the initial data collection period when the energy audit took place.

Deriving heat load. We multiplied the hourly gas use by the furnace efficiency to obtain the hourly heating load for each house. We obtained the hourly ambient temperatures for each home during the window of time the utility data was provided by the utility (e.g. 11/10/2020–11/11/2021) using the NOAA Local Climatological Data (LCD) Tool for the closest available weather station.

- *Heat pump model.* We calculated the heat pump hourly temperature-dependent coefficient of performance (COP) using the following equation:

$$COP_i' \times (1 - l(t_i)) = COP_i \; Tmin < t, \; i \in 8760$$

$$COP_i = 1 \; t < Tmin$$

Where:

***i* indexes hour;**

***COP'* = manufacturer reported coefficient of performance** using the efficiency curve (ambient temperature vs. COP) of the Mitsubishi M2i cold climate ASHP for heating;

***l()* = defrost efficiency loss for give temperature, t (%);**

t = **hourly dry bulb temperature (F)** using the NOAA LCD weather data for the same period for which had metered natural gas data for each home;

COP = observable coefficient of performance;

$T_{min} = 10°F$ reflecting ambient temperature change over point from heat pump to backup heating mode via electric resistance coil;

$<T_{min}$ **COP** $= 1$ reflecting the heating efficiency of an electric resistance coil used for backup to ensure that heating setpoints are met below the change over point.

We calculated percentage improvement in cooling energy by dividing the Mitsubishi H2i SEER rating (SEER = 17) by the on-label AC efficiency obtained from the energy audits for each home. This kind of high efficiency equipment comes with a first cost premium over a standard furnace replacement. It is therefore expensive for low- and middle-income households and is likely not affordable without a subsidy that covers most of the cost. Selecting this equipment is a conservative assumption. We then applied this factor to an average cooling energy percentage obtained from the Resstock End Use Savings Shapes (Wilson et al., 2022) to determine the annual energy cost savings.

- *Energy cost calculation.* We calculated the energy cost using a model we developed in R that takes in the hourly estimated electric and daily gas usage for the hypothetical heat pump scenario and calculates the total bill costs in the manner calculated by the utilities as published in the electricity and gas rate schedules ("DTE Electric Company Rate Book for Electric Service", 2023). For example, to calculate the annual electricity cost for each home, we apply the flat rate service charge per month, capacity and non-capacity energy charges assessed per kWh, as well as surcharges and credits. We completed this process for three electricity rates and two gas rates to test the sensitivity of our results to rates available to participants. See Figure B.7 for rate summary and Note D.5 for rate description. We do not include tariff changes from one year to the next because future rate changes are unpredictable and beyond the scope of the analysis. Changes in consumer behavior associated with changes in utility tariffs are also beyond the scope of the paper and therefore not included in the analysis. Additionally, incorporating behavior changes would not have a meaningful impact on the results because short term elasticities are low for electricity and natural gas in the US (U.S. Energy Information Administration, 2021).

2.5. Resstock

We analyzed the potential for energy efficiency to mitigate cost increase due to heat pumps by calculating energy costs derived from four modeled retrofit scenarios included in the NREL Resstock End Use Savings Shapes database (Wilson et al., 2021). We selected hourly load profiles available for a baseline case and three "upgrades" including full electrification with or without deep efficiency retrofits, and deep efficiency retrofits with no change to the HVAC systems. To these scenarios, we applied the utility rates for all sensitivity cases as described above. We then calculated the mean incremental annual energy costchange resulting from a series of these changes across a random sample of 400 homes in the database representative of Detroit, MI.

2.6. Retrofit cost analysis

The contractor recommended energy efficiency measures and provided first cost and utility cost savings estimates for the recommended work. We used the "Return on Investment and Rebate Report" prepared for each study participant to summarize the recommended energy efficiency upgrades to code the unique efficiency measures recommended across the sample.

The parameters we used for estimating the feasibility of retrofitting were economic payback in years for the package of all recommended retrofits (calculated as the first cost divided by the annual energy cost savings), the first cost of the total package, and the modeled utility cost savings for the individual measures. The values for these parameters were obtained from the retrofit reports provided to participants by the energy audit contractor. The payback parameter described above follows the US Department of Energy Methodology and Procedures for Life Cycle Cost Analysis (Code of Federal Regulations. 10 CFR Part 436 Subpart A). No discount rates are used, making this the best-case estimate of the payback period. Given our findings, the decision to use an undiscounted payback period is conservative: if a discount rate were applied, the payback period would be even longer, strengthening our argument that the retrofits are not attractive on the basis of utility bill savings. Additionally, we show the rates that participants were provided as part of their energy audit, so payback periods not inclusive of a discount rate are more representative of the data participants have to inform their decision making.

3. Results

We find that electrifying homes with heat pumps increases annual energy cost by 58 % on average (range: 11–182 %) when compared to natural gas heating and considering a flat electricity rate, higher than previous estimates. This change exacerbates already high energy burdens for low-and-moderate income (LMI) households. While we find energy retrofit opportunities that saved energy cost for every home, they came with substantial obstacles that could limit uptake. There is an average payback period of 24 years and homeowners can be left without sufficient information to act, even after a visit from a home energy auditor. Willand et al. (2020) identified this situation as the retrofit trap in their 2020 analysis of Australian home retrofit programs. It can be understood as a form of poverty trap, defined Azaiadis and Stachurski as a reinforcing mechanism that acts as barrier to adoption of techniques that can alleviate poverty (Azariadis and Stachurski, 2005). The clean energy transition is hindered by an energy poverty trap because the extensive retrofits needed to make electrification affordable are themselves too expensive for low-income households.

3.1. Housing quality vs. set-point choices

We estimate energy burden for each household by calculating the proportion of their annual combined electricity and gas cost (sourced from utility bills) to the self-reported income range. The 5 highest energy burdened households have rates ranging from 10 to 40 %. 32 % of homes have energy burdens greater than 6 %, which is considered a high energy burden and twice the national average (Drehobl et al., 2020). All these households have below-median incomes. 37 % are between 3 and 6 %. 31 % of homes have an energy burden below 3 %; all but one of these homes have incomes that exceed the local median (see Figure B.1). See Table C.1 for descriptive statistics on utility costs and energy burden. Table C.6 provides a list of self-identified household income ranges and a comparison to the area median income (AMI) by zip code.

Not all homes in our sample were of the same age and quality. The homes were on average 60 years old and built in an era during which Michigan did not have energy efficient building codes.[2] These codes were adopted for the first time 1977 when ASHRAE 90–1975 was adopted state-wide ("US Dept. of Energy Building Energy Codes Program", 2024). 13 homes (5 in the <$25k income group and 8 in the $25–50k group) had been retrofit by Habitat for Humanity of the Huron Valley (Habitat) resulting in higher quality for their age. Improvements had been made 1–10 years prior to participating in this study.

Homes retrofit by Habitat perform consistently better than market rate homes in the sample [Fig. 1]. To understand the impact of these

[2] They were adopted for the first time 1977 when ASHRAE 90-1975 was adopted state-wide. (US Dept. of Energy Building Energy Codes Program, www.energycodes.gov/status/states/michigan).

retrofits on overall home energy efficiency, we examine the difference between trends of annual energy use per unit floor area (or energy use intensity) and per occupant across income in market rate homes compared to the Habitat homes. When treating self-reported income categories as an ordered set (<$25k, $25–50k, $50–75k, and >$75k) in a least squares regression of energy use intensity (EUI) per occupant on income, we find a significant downward trend (p-value=0.048) for market-rate homes, indicating that low-income households either live in less energy efficient homes or there is significantly different behavior across income levels.

The latter explanation would suggest, for example, that lower-income households start to use heating at higher ambient temperatures and cooling at lower ambient temperatures. Cong et al. provide evidence to the contrary. They find that lower-income families wait for ambient temperatures to rise higher before turning on air conditioning compared to those with higher incomes (Cong et al., 2022). This would imply that low-income families use less energy, a seeming contradiction of our results. However, we believe that there is no contradiction, since the Cong et al. results are not directly comparable to ours for two reasons. First, we report energy use per square foot per occupant, which Cong et al. do not observe. Second, Cong et al. have studied air conditioning, whereas energy use in our sample is dominated by heating. Huang et al. (2023) do find evidence that low-income households start to heat earlier in the season and heat for more months of the year than higher-income households. However, these results are also not comparable to ours since there is no normalization by area or occupancy. We estimate the heating inflection temperature (HIT), or the outdoor temperature at which each household turns on the heat because in every case heating constitutes the highest proportional energy expenditure (>60 %). To estimate the HIT, we calculate a linear splitwise regression of metered daily gas use on ambient air temperature. We find no significant trend in HIT across income (see Figure B.2). Combined, our findings and those of Huang et al. (2023) suggest that behavior-driven energy use patterns are unlikely to explain the higher energy use of low-income homes.

Observed heating and cooling setpoints—read from participants' smart thermostats—likewise reveal that lower income households do not on average choose higher setpoints in winter or lower setpoints in summer [Fig. 2a]. We do observe greater variance in the set points that households in the lowest income group (<$25k) choose [Fig. 2b], as well as in the indoor temperatures that they experience [Fig. 2c]. This suggests that, even though they have higher energy use intensity, these households are actively trying to manage their energy use and comfort by manipulating their set points. This provides evidence that the higher EUI is in fact due to poorer building envelopes and not because lower-income households are choosing consistently different setpoint temperatures.

We look at housing characteristics to explore whether the homes occupied by low-income households are in fact less efficient. Blower door testing conducted at each home provides an empirical measure of efficiency by measuring air infiltration. Low infiltration signifies high efficiency. We find that the homes retrofit by Habitat have better performance than market-rate homes in the sample. The median measured air infiltration rate of Habitat homes is almost half that of their counterparts (4.2 ACH 50 and 7.7 ACH 50, respectively) with less variability (range: 2.9–5.9; IQR = 3.4–5.3 and range: 3.2–17.5; IQR = 5.8–10.9, respectively). Applying the same regression method described above, after excluding Habitat homes, we find a significant downward trend (p-value = 0.023) for market-rate homes, indicating that the lower-income homes are indeed less efficient (Figure B.3).

3.2. Energy burden

For the 51 houses in our sample, we calculate the electricity loads that would result from replacing natural gas furnaces with air source heat pumps for space heating (see Supplementary Methodology for more detail on reduced complexity model and load derivation) and apply the most prevalent gas and electric utility rates across the sample to determine the energy cost change associated with this replacement. We calculate change in annual energy bills and energy cost burden which refers the difference in energy expenditures and percentage of income spent on utilities, respectively, between the baseline scenario and the heat pump scenario. 41/51 households were on a standard time-invariant rate, which will be discontinued as of May 2023. 10 had elected different rate structures, which include time-of-use rates, interruptible cooling rates, and specialty rates designed for low-income households. We find that switching to a heat pump would increase annual utility bills for every household in the sample, and that the cost goes up by $1154 on average (see Table C.3).

Our results show variability in median cost change across income and a disproportionate concentration of high energy burden increase below median income (<$25k and $25–50k). The median cost increase for below median income households is $801 ($n = 28$), constituting a 37 % utility spending increase on average. There is a 49 % utility spending increase for above median income households on average ($n = 22$) [Fig. 3a-1]. Even though the median cost increase is nominally lower for

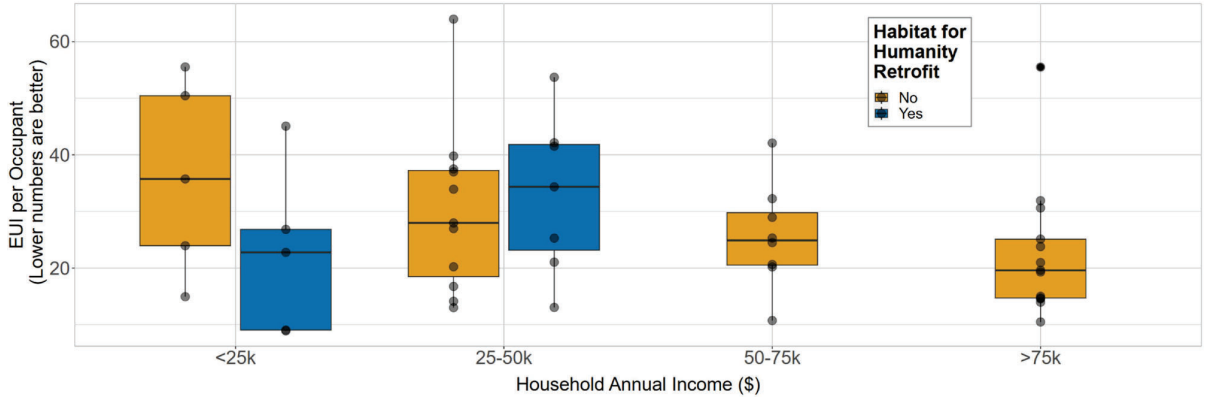

Fig. 1. Energy use intensity per occupancy by income group. Annual energy use per floor area divided by the number of occupants is shown here. The x-axis represents four income categories to which participants were assigned given the income range they provided. Each box plot shows the median (middle line), first and third quantiles (lower and upper box bounds), and minima and maxima (whiskers). The blue boxes represent homes that have been retrofit by habitat for humanity, which perform better than market rate homes in the sample (represented by oranges boxes) for homes earning less than $25k. Each dot represents one household. Using a non-linear least squares regression, we find a significant downward trend (p-value = 0.048) among market rate homes, indicating that those with lower incomes live in less efficient homes.

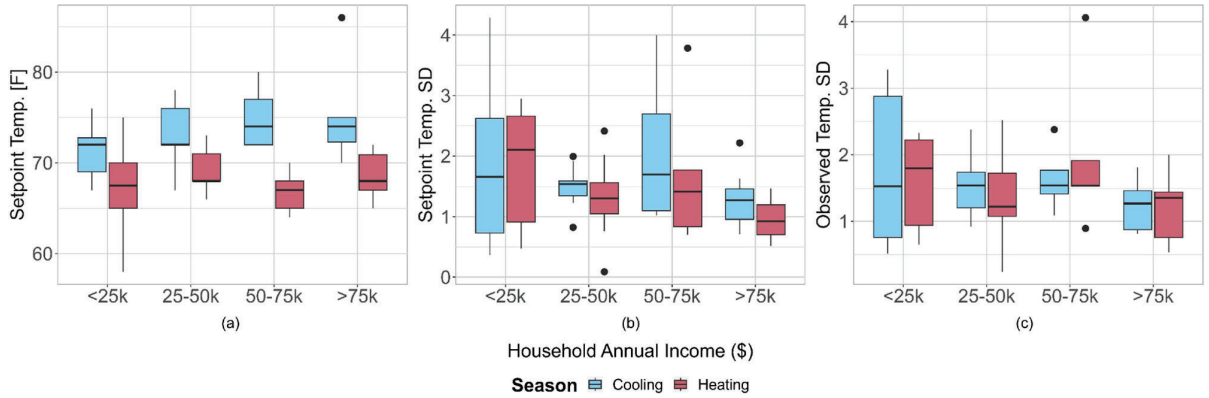

Fig. 2. a-b-c: Thermostat setpoint and observed indoor temperature by income. Observed heating and cooling setpoints (a), setpoint standard deviation (b), and indoor temperature standard deviation (c) on smart thermostats for each home.

below median income households, their energy burden increase is 4 times higher on average than those at or above median income [Fig. 3b-1]. Additionally, all households earning median income ($50–75k) and above (>$75k) - which currently have a median energy burden of 2.6 % – would experience a median change in energy burden of greater than 1 percentage point, indicating that energy burden could become a concern for households which are currently energy secure.

3.3. Time of use electricity rates

We examine the impact of two time-of-use rates available to all customers in the study region on the annual increased utility costs and energy burdens of the sample for a hypothetical conversion to heat humps. Switching to the standard time-of-use rate (DTE no. D1.11) ("DTE Electric Company Rate Book for Electric Service", 2023) reduces the mean cost increase for the sample by $120 per year from $1154 to $1034 (see Fig 3a-2) relative to a flat rate. Under this rate, the median

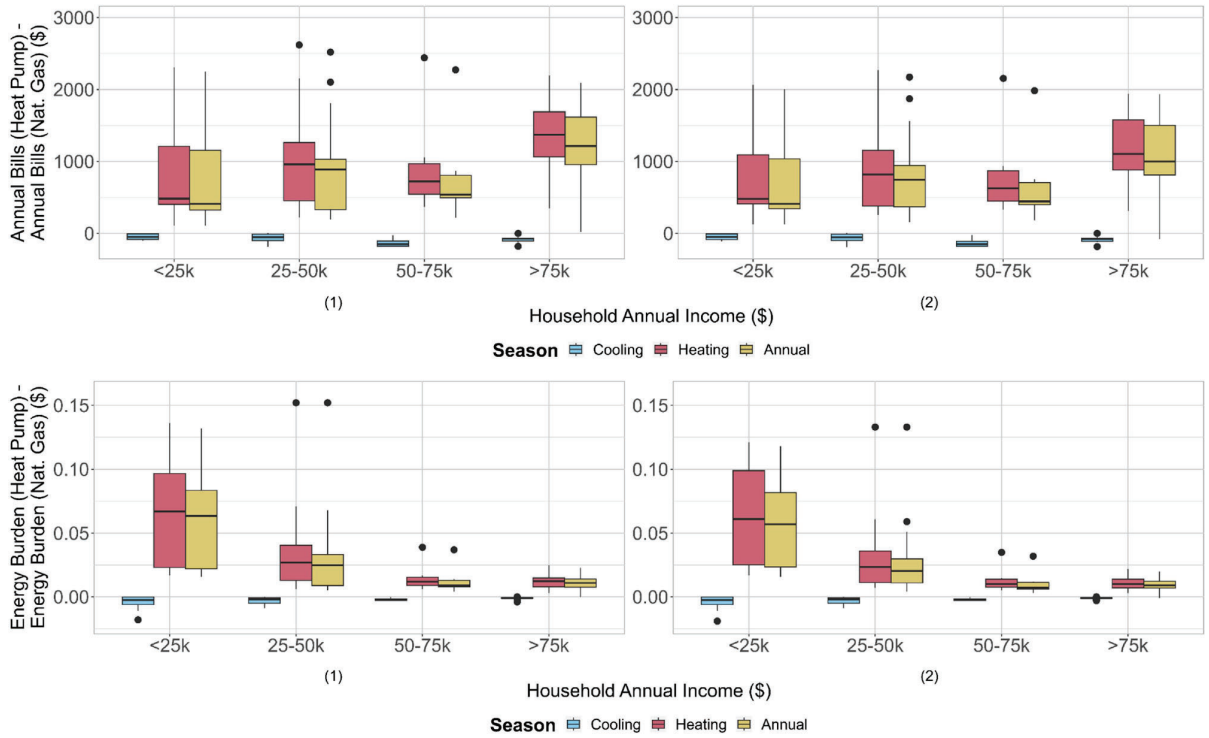

Fig. 3. a: Change in annual energy bills for switching to a heat pump from natural gas heating by income. The x-axis represents four income categories to which participants were assigned given the income range they provided. Dot represents outliers. Each box plot shows the median cost increase (middle line), first and third quantiles (lower and upper box bounds), and minima and maxima of change in utility cost change for (1) standard flat electricity rate and 2022 natural gas cost; (2) standard time-of-use electricity rate and 2022 natural gas cost.
b: Change in energy burden for switching to a heat pump from natural gas heating by income. The x-axis represents four income categories to which participants were assigned given the income range they provided. Dot represents outliers. Each box plot shows the median energy burden increase (middle line), first and third quantiles (lower and upper box bounds), and minima and maxima of change in energy burden change for (1) standard flat electricity rate and 2022 natural gas cost; (2) standard time-of-use electricity rate and 2022 natural gas cost.

utility cost change due to heat pumps is lower for every income category. The effect of this lower cost change is minimal for energy burden, reducing the rate by less than 1 percentage point for each category [Fig 3b-2].

By comparison, relative to a flat rate, the optional time-of-use rate (DTE no. D1.2) (DTE Electric Company Rate Book for Electric Service, 2023) would worsen the increase in annual utility cost for switching to a heat pump for all income groups. Switching to D1.2 increases the mean cost increase for the sample by $623 per year to $1777 (see Figure B.4). This rate nearly doubles the median energy burden changes for all income groups earning less than $75k (see Figure B.5). The D1.2 rate had a higher cost per kWh at peak times and a peak window two hours longer than the D1.11 rate. These rates impacted each household differently given the variety of occupants, schedules, housing vintage across the sample. For instance, those who saw the greatest cost increase with the standard time-of-use rate had the oldest, least efficient AC units in the sample and used their cooling systems during the peak window, whereas, in reality, the switch to a heat pump would include a new, more efficient AC.

While the gas commodity prices have risen dramatically from 2021 to 2023, the delivered price of natural gas for residential customers has in fact been modest and does not affect the results. See Figures B.4 and B.5 for a comparison of annual bill and energy burden changes with 2021 and 2023 gas rates. See Table C.2 for a detailed comparison of all of the electricity and gas rates available to DTE customers as of 2023 and their impact on baseline household energy use.

3.4. Energy retrofit model

Energy retrofits are a possible strategy to mitigate this increase in bills. Since we do not have empirical estimates of cost savings potential of envelope improvements to mitigate the cost increase of heating electrification, we first model the corresponding energy uses using the NREL ResStock End Use Savings Shapes (Wilson et al., 2022). We randomly sample 400 Michigan homes heated with natural gas from the database and examine four scenarios: baseline envelope with natural gas heating, envelope upgrade, heat pump upgrade, and combined heat pump and envelope upgrade. To then convert the energy uses to cost, we apply the electricity and gas rates experienced by 41/51 of our study participants to the hourly electricity and gas loads to estimate the relative cost impact of retrofits for the natural gas scenario and the heat pump scenario.

We find that transitioning to a heat pump without energy retrofits results in a mean utility cost increase of 26 % over the baseline. Adding a comprehensive envelope retrofit improvement mitigates this cost premium and drives utility costs back to what they were with natural gas heating with the existing envelope. Energy efficiency retrofits alone reduce bills by 11 % compared to the baseline condition [Fig. 4].

See Note D.1 for a comparison of the modeled results to the estimates calculated using observed data from the field study, including a breakdown of model findings by house vintage (Figure B.6).

3.5. Contractor retrofit recommendations

Our results suggest that, with energy retrofits, most homes would not experience an increase in utility bills relative to the status quo if they shifted to heat pumps. Based on REM/Rate (REM/Rate 2024), commonly used software, our contractor recommended a different combination of ten individual retrofit measures for the homes in our sample and these upgrades are expensive with long payback periods. The most commonly recommended measure is air sealing, an intervention in which joints are sealed to reduce air infiltration. We classify building envelope upgrades as simple if they can be completed by one contractor (e.g., spraying cellulose in the attic) and complex otherwise (e.g., foam injection into drywall). Upgrades to the HVAC system are in a separate category, as are upgrades to other appliances (e.g., fridges) (see Figure B.8). The median retrofit package costs are about 10 % of household income. ($3250 for <$25k; $4700 for $24–50k; $10,300 for $50–75k; $7000 for >$75k) (see Figure B.9). 14 households in the lowest three income groups are faced with total package costs of more than 20 % of their income. The median payback period across the sample is 24 years, with a large variance across the income groups (see Figure B.10).

Upfront cost and simple payback estimates for retrofits match previous studies. Fowlie et al. (2018) use empirical estimates for actual energy savings across the Michigan WAP and find internal rates of return (IRR) at −10.6 % (10 year), −2.3 % (16 year), and 0.21 % (20 year). We find even lower IRR for the recommended retrofits by the energy

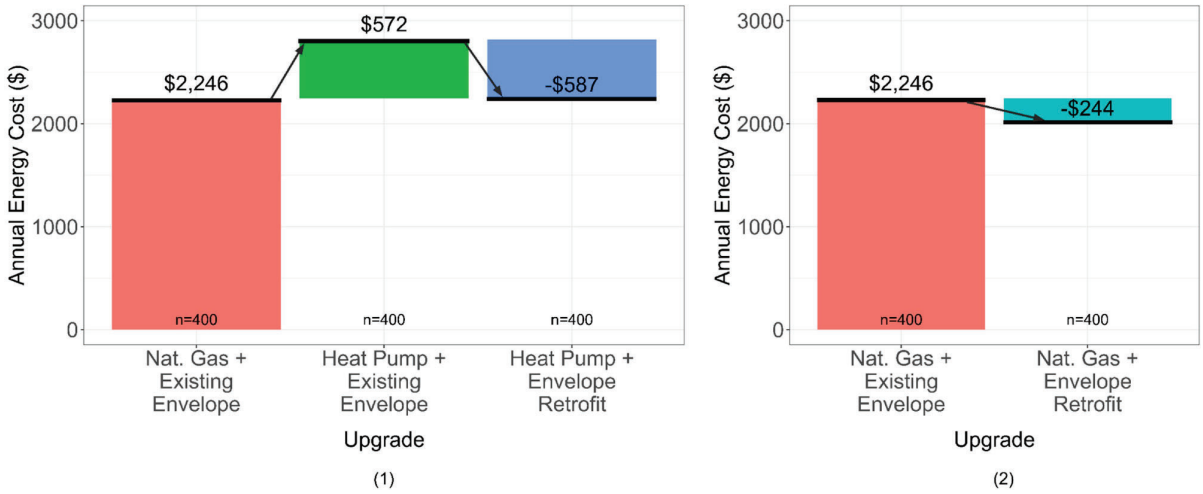

Fig. 4. Modeled mean annual energy cost impact of heating electrification and envelope improvements. (1) The baseline case (natural gas heating with existing envelope) represented in red is compared to two upgrades: heat pump with efficient envelope retrofit (green) and heat pump without envelope improvements (blue). (2) The baseline case (natural gas heating with existing envelope) represented in red is compared natural gas heating with efficient envelope retrofit (teal). Means represent 400 randomly sampled homes from the ResStock end use load profile database that use natural gas in Michigan. Using a Kruskall–Wallace test, we find a significant difference between the medians of the utility costs in each upgrade category (p-value < 0.01). We test the null hypothesis that the medians were the same using a pairwise with the Bonferroni adjustment and similarly find significant differences for each comparison.

assessment contractor: −16.1 % (10 year), −5.3 % (16 year), and 2.2 % (20 year). Less et al. (Less et al., 2021) estimate an archetypical retrofit package for a single family house that includes the most common retrofit recommendations in our sample (attic floor insulation, air sealing, foundation floor insulation) based on actual US construction costs at $7825 (see Note D.2 for measure cost calculation). The mean upgrade package cost estimated by the energy audit contractor in our sample is $7628 and the median is $5900 (see Figure B.9). Since the package described by Less et al. excludes system or appliance measures, we surmise that it is likely our contractor's costs are underestimates. Realized project costs could be higher, and payback periods longer.

There is no clear pattern about what measures are most cost-effective. The results show a large range of annual cost savings available from the recommended retrofit packages, with annual utility bill savings ranging from $26 to $730 [Fig. 5a]. We find that air sealing, which was recommended to all households, provides a payback range of 3.7 to 144 years [Fig. 5b] and attic insulation alone provides a payback range of 20 to 259 years (see Note D.2 for measure cost calculation). The high-end estimates that reflect payback periods much higher than seen in the literature are due a sample-specific scenario in which 25 % of the homes in the study received energy efficiency retrofits before the study period. For these homes, which were already high performing, the contractor recommended improvements to existing conditions (such as attic insulation and air sealing), which resulted in marginal energy savings and therefore long payback periods.

4. Discussion

We explored the drivers of energy inefficiency, explored the economic impact of replacing natural gas furnaces with heat pumps by income, assessed a range of energy retrofit measures that could support utility cost reduction in the 51 Michigan households we studied, and compared this impact to estimates from a national model. Heat pumps raise energy cost and energy burden disproportionately for low-income households. The median utility cost increase for switching to a heat pump is lowest for low-income households because they use the least amount of energy. This finding is suggestive of an efficiency paradox (Goldstein et al., 2022) where the lowest consuming households live in the least efficient homes, indicating that they are likely not using enough energy to meet their health, safety, and comfort needs. Yet, the increase in energy burden is disproportionately higher for low-income groups because even though their cost increase is nominally the smallest, it is a greater percentage of their annual income. Our results show that adopting heat pumps results in a fmedian energy burden increase of 75 % and 54 % for both income groups earning below AMI (<$25k and $25–50k, respectively). Given that households below median income have a 6 % median energy burden on their existing natural gas heating systems, such increases would severely worsen existing energy insecurity, for instance increasing risk of poor health (Reames et al., 2021) and coping behaviors like trading off paying utility for paying for rent or food (Hernández, 2016), or the underconsumption of energy in household who struggle to pay their bills (Meyer et al., 2018; Barrella et al., 2022; Faiella and Lavecchia, 2021; Antepara et al., 2020).

Policymakers should act to help lower the operating costs of heat pumps compared to natural gas for low-income households in cold climates. This can be done in three ways. First, government-sponsored initiatives to advance more efficient heat pump technology like the U.S. Department of Energy Residential Cold Climate Heat Pump Challenge are essential to improve energy bill affordability of fuel switching. More efficient heat pumps reduce the utility cost premium over natural gas furnaces.

Second, state regulators should exercise a more robust scrutiny of utility company returns and create more opportunities to improve customer outcomes in the rate making process. For example, the Michigan Public Service Commission recently ruled in a disputed rate case in the study region that resulted in allocations for energy retrofits in historically underserved areas due to intervening efforts from customer groups not typically represented in rate making like community

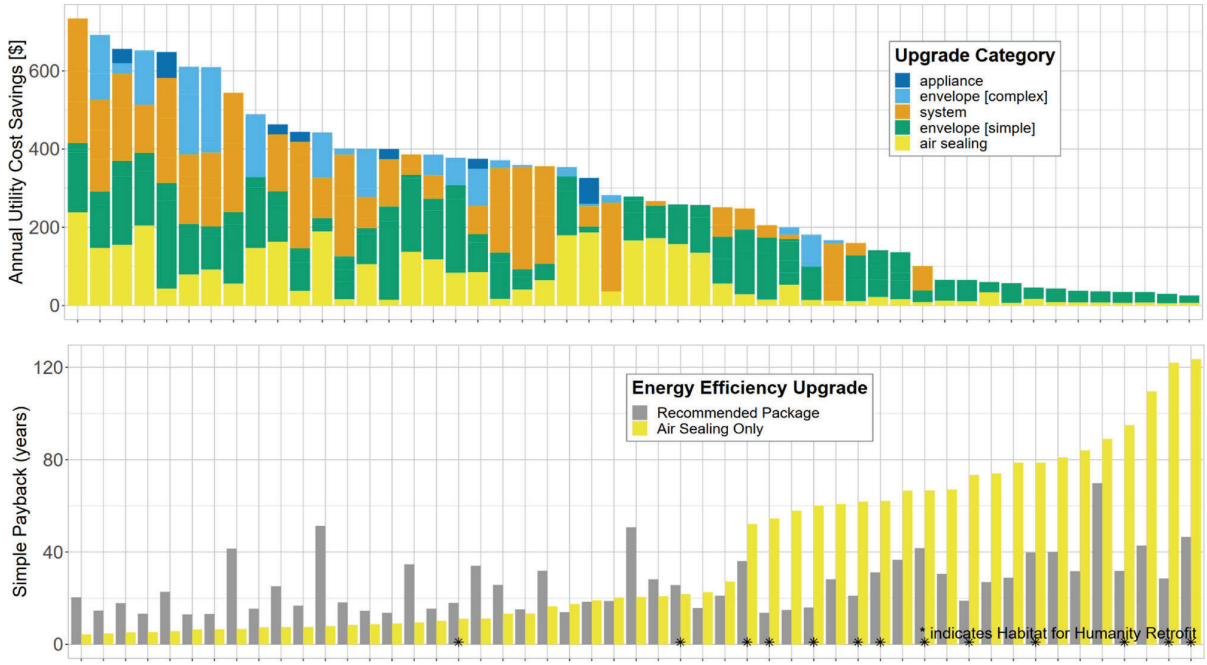

Fig. 5. a: Annual utility cost savings for retrofit packages by household. Colors represent categories we develop to indicate the relative cost and difficulty of adopting the recommendation. There is no clear pattern for which energy retrofits provide the best payback.
b: Simple payback for the recommended package and air sealing by household. Gray bars represent the payback for the full retrofit package recommended for each home. Corresponding yellow bars represent the air sealing payback period for that home. Star indicates houses that have been retrofit by habitat for humanity.

advocates and municipal governments (Hon et al., 2023). A high ratio of per-unit electricity to gas rates makes heat pumps less attractive than natural gas furnaces.

Third, states should consider implementing percentage of income payment plans (PIPP) that place a cap on energy expenditures relative to household income. These programs can be paired with federal- and state-funded retrofit programs to simultaneously improve the building stock and mitigate energy poverty. Capping household utility costs insulates low-income households from increase in bills.

Local factors exacerbate the economic penalty for household heating electrification described in this study and pose additional barriers to change not found in other regions. In our study sample, the average electricity cost is $0.18 per kWh and gas costs $0.8 per 100 cubic feet, or $0.03 per kWh. Per unit energy, electricity is therefore 5 times more expensive than gas, which is a large-enough difference that the higher efficiency of heat pumps is unable to compensate for it. (See Table C.4 for energy burden changes by income). Our results show that under these circumstances, energy cost increases for heating electrification could be disruptive even for households earning twice the median income.

Low-income households will need expanded and flexible financial assistance to retrofit their homes to prepare them for electrification. The subset (25 %) of homes that received deep energy retrofits prior to the data collection period had consistently more efficient air sealing and attic insulation than the market-rate homes. Retrofits to improve the performance of these characteristics were the most frequently recommended to study participants by the contractor, but we found they had a large range in payback period. There was no clear best choice investment that would provide either the greatest utility savings or the best payback, making it difficult for policymakers to make broadly-applicable recommendations for energy efficiency retrofits.

The group of very low earners (<$25k) with low energy burdens living in highly efficient homes were the same households that experienced the lowest energy burden increase due to heat pumps. This demonstrates the value of energy efficiency improvements in buffering households from the impact of utility cost rise due to electrification. However, the retrofits that provide the remedy are expensive. Our findings suggest that actual upfront costs for recommended retrofits in homes that have not been renovated far exceeded the $7700 cap for the Weatherization Assistance Program. Additionally, the payback periods in many cases were so high the projects would not qualify for the program, which requires a 1:1 saving-to-investment (SIR) ratio without consideration of discount rates. Current programs need to be expanded to cover the cost of expensive upgrades, and to be made available to more homes.

5. Conclusions

Policy action is needed to make heating electrification viable. The economics of electrification are adverse for the existing housing stock in cold climates. Our findings suggest that heat pumps are not a feasible economic alternative for households currently using natural gas, unless governments offset energy cost premiums through public funding. Some of the policy discussion around heat pumps does not acknowledge this (U.S. Department of Energy, 2023; Rewiring America, 2021; Fathollahzadeh et al., 2022). Such an investment can be justified on the basis of equity and by internalizing the social cost of carbon, current estimates of which are ~$180 per ton CO2 (U.S. Environmental Protection Agency, 2022; Rennert et al., 2022).

Coupling heating electrification with retrofits in existing homes with natural gas heating can limit utility cost increases and reduce a key barrier to heat pump adoption. At the same time, our study shows that even after a visit from a home energy auditor, homeowners can be left without sufficient information to act. The reports they are provided could be more useful in supporting investment decisions by providing a marginal abatement curve specific to each house, where the payback period of each measure is plotted against the cumulative cost of all the recommended measures. The homeowner can decide the most they are willing to spend, and the curve would show them all the fastest-payback measures that can be implemented for that amount.

The impact of rate structures should be analyzed based on empirical data from the rate base. Time-of-use rate design for electricity determines the cost increase for switching to heat pumps. We estimate that one rate (D1.11) reduced the increase in bills by 10 % compared to the flat rate (D1), while the other (D1.2) further elevated the average cost increase by 56 %. Modeled results using ResStock show the opposite, where the D1.11 rate is usually no worse than the flat rate (see Figure B.7 for utility rate comparison). Using empirical energy use data in utility rate design to understand how proposed rates affect households across the income spectrum and across housing quality given future adoption of heat pumps could help mitigate energy insecurity and promote greater access to heat pump adoption among natural gas users.

While our focus on Michigan allows us to understand the cost dynamics for electrification in a cold climate with high prevalence of natural gas use, limitations of our study include the small sample size and the limited regional scope. Additionally, we were unable to incorporate homeowner attitudes regarding converting their natural gas heating systems to electric heat pump systems. Future work will investigate these perceptions, examining the factors that influence decision making for residential electrification and further examining potential barriers to equitable adoption of heat pumps across income.

Ethics statement

The University of Michigan's Institutional Review Board reviewed and approved this research based on informed consent by study participants.

CRediT authorship contribution statement

Claire McKenna: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Project administration, Methodology, Investigation, Formal analysis, Data curation, Conceptualization, Funding acquisition. **Carina Gronlund:** Writing – review & editing, Supervision, Conceptualization, Methodology, Visualization, Formal analysis, Project administration. **Parth Vaishnav:** Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Project administration, Methodology, Investigation, Formal analysis, Data curation, Conceptualization, Supervision, Funding acquisition.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

Claire McKenna reports financial support was provided by U.S. Department of Energy and University of Michigan. Parth Vaishnav reports financial support was provided by University of Michigan.

Data availability

Model inputs and aggregated data that support the findings of this study are available from the corresponding author upon reasonable request. Demographic information for participants and raw data is not available in accordance with the informed consent agreement signed by study participants.

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Supplementary materials

Supplementary material associated with this article can be found, in the online version, at doi:10.1016/j.resconrec.2024.107699.

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Ful ue

n guth a g tar hi gu cn Hwj l s: n guth Btuad tar hi gu cn o wj–H r ugsr uth l u Bd stayumr CuMBdshgah Bds adC udl gBdMudhay guyul adt u hB si sh a d Cut agKBd , ah Bd

o MdGa Hy baPuu[aVK] Vvah Ma * i Mha, [aVKVA] VRg GadTa I i Mag [aVK] VL uBgE Bs N: I agad TByBs [tVC] V Hyussad CgB n ut agys [uVO] Vpi CBl t v: n i Múu [aVKVA]

[a] *S chd h f r lEnvilnat andhvnu nr ms b cnu lyho hr, Unnsy cnu lyho Mrglr nnvlr gt Ahi I o RhPcob hu dHt I KH achKlt f r lm, I vhK Mu lvhmi*
[K] *wninhvyc hr, :r r sEhnts r b nr nv 1 r . a Rhr su hnnvlhai Lw:b. a-t S chd h f r lEnvilnat Ahi I o RhPcob hu dHt I KH achKlt f r lm, I vhK Mu lvhmi*
[t] *andhvnu nr ms b cnu lyho Mrglr nnvlr gt f r lEnvilna s Uhnnhit . 2pCD Uhnnhit 3 vnnyn*
[C] *:rinhnhm s b cnu lyho Mrglr nnvlr g Aylnr ynit qs Hr, hnts r s v wninhvyc hr, 4ryc r s o sgex Onahi Lq1 w4OT:b MO4-t . 2pCD Uhnnhit 3 vnnyn*
[u] *wninhvyc hr, :r r sEhnts r b nr nv 1 r b1 . hr, Oe, vsgnr Lw:b O-t S chd h f r lEnvilnat I v5hr hc Unnylr ynt I KH achKlt f r lm, I vhK Mu lvhmi*
[O] *S chd h f r lEnvilnat andhvnu nr ms 3 ns iylnr ynit Ahi I o RhPcob hu dHt I KH achKlt f r lm, I vhK Mu lvhmi*

H F fi f w p S f N v o

Snek sv, i6
n guth H g war hi gu cn Hwj
n guth o tuad war hi gu cn o wj
wagKBd tar hi gu
. tayumr r Bhudhay
fiut WdBmt BdBM tay assussMudh

H z . fi F H w fi

Hs hWu ahMBsr Wugt t Bdtudhgah Bd BOwo$_5$ shua C yG dtguasus adC hWu e BgyC Egarr yus e hWhWu r guss dE t Wayyud Eus BOEyBKay e agM dEV dhug dah Bday gusuagt WtBMMi d hus agu ath l uyGu1 ryBg dE dl udh l u hut WdByBE us hB t BMKah hWu aCl ugsu uOBths BOuyul ahuC wo$_5$ yul uys: Hd Mr Bghadht Wayyud Eu d hWs t Bdhu1h s hB u1hgath wo$_5$ C gut hyG QBM hWu ahMBsr Wugu: wBdsu-i udhyGV tar hi g dE hWu yash QBM suae ahug s tgi t ay Ci u hB hs Mr ath Bd hWu Cuy tahu Kayadt u BOMag du ut BsGshuMs adC hWu r Bhudh ayt Bdsu-i udt us OBg EyBKay ty Mahu guEi yah Bd: x Wyu n Hw adC n o w sVBe r Bhudh ayh Be agCs t BMKah dE ty Mahu t WadEuVt Wayyud Eus dt yi C dE WEWBr ugah Bday t Bshs adC hWu duuC OBg Oghwhg hut WdByBE t ay aCl adt u Mudhs r ugs sh fiWs r ar ug t g ht ayyG C sti ssus hWu sha hi sVt Wayyud Eus VadC st ayaK yhG BOn Hw adC n o w ah r yBh Bg dCi shg ay st ayu: I uG t Wayyud Eus dt yi Cu t ar hay adC Br ugah Bday t Bshs Vudug EG Cum MadCs VadC dhuEgah dE Eguud udug EGs Bi gt us hB guCi t u udl gBdMudhay Mr ath fiWu gul ue uMr Was , us Bd hut WdBm ut BdBM t ay Kudt WMag T dE ada yGsus hB ul ayi ahu Oas K yhG OBg yag Eumst ayu Cur yBGMudh adC hWu g uOBth l uduss d M h Eah dE wo$_5$ uM ss Bds adC ath dE as hBBys hBe agCs Cuy Bt ay, uC wo$_5$ r gBCi th Bd:

Sp ot lighs l1gt

Hs CuP duC e hWd hWu Rag s aEguuMudhs adC hWu L yBKay wy Mahu Ht m h Bds VaddBi dt uC ah hWu wo R56 t BdOugudt u WBshuC KG hWu %d huC Nah Bds d 505k VEyBKay huMr ugah i gu g su s WBi yC dBhu1t uuC 2:4 °w t BMr aguC hB r gumd Ci shg ay huMr ugah i gus hB y M h hWu Mr ath BOt y Mahu t WadEu q2U: (i Mad Cur ud Cud t u Bd OBss yO1 uys s shyyCBM dadh adC hWu hgads h Bd hB Eguud udug EG r gBCi th Bd Bg Cut agKBd , ah Bd sByi h Bds BdEB dE q5U: fd BgCug hB M h Eah u r ash adC t i ggudh uM ss Bds VhWu t ar hi gu Blug 20 E Eam hBds BOEguud WBi su Eas us Vr g Mag yG t agKBd C B1 Cu cwo$_5$j addi ayyG QBM hWu a g KG 5040 hB guMa d KuyBe hWs 2:4 °w hWgus WByC qkU: Nu Eah l u uM ss Bds agu ussudh ayay BdEs Cur B dhs Bi gt u t ar hi gu Kut ai su hWuG BOOug a Muads hB at h l uyG guMBl u t agKBd C B1 Cu QBM hWu ah MBsr WuguVWuyr m dE hB BOOuhuM ss Bds hWah agu C OPt i yh hB uyM dah u udh guyG: n guth H g war hi gu cn Hwj adC n guth o t uad war hi gu cn o wj r yaGt gi t ay gByus e hWd hWu KgBaCug sr ut hgi M BOduEah l u uM ss Bds hut WdByBE us VtBMr yuMudhm dE ar r gBat Wus si t Was aOBgush ah BdVz BudugEG e hW wagKBd war hi gu adC . hBgaEu cz Sww. j VadC o t uad HyTay d hG SdWadt u Mudh co HSj q6V: U: x Wyu r B dhs Bi gt u t ar hi gu hagEuhs sr ut Pt uM ss Bd r B dhs Vn Hw adC n o w r gBl Cu aCC h Bday al udi us OBg tagKBd guMBl ay Bd a yagEug st ayu V t Bdhg Ki h dE hB Blugayy uOBghs hB t BMKah t y Mahu t WadEu: fdhuEgah dE hWusl ag Bi s hut WdByBE us ayyBe s OBg a MBgu t BMr guWuds l u ar r gBat WhB at Wul dE duEah l u uM ss Bds EBays adC M h Eah dE hWu Mr ath s BOt agKBd C B1 Cu att i Mi yah Bd d hWu ahMBsr Wugu q; U:

n guth H g war hi gu cn Hwj s a suh BO hut WdByBE us hWah dl Byl us ul hgath dE wo$_5$ C gut hyG QBM hWu ahMBsr Wugu q) U: n Hw Was Kuud CuMBdshgahuC ah yaKBgah BgG st ayu adC r gumd Ci shg ay st ayu adC hGr tayyG uMr yBGs aKs Bgr h Bdm Bg aCs Bgr h Bdm KasuC r gBt ussus hB shg r wo$_5$ MByum t i yus QBM hWu ahMBsr Wugu: o dt u t ar hi guCVhWu wo$_5$ Mi sh Ku u hWug i h m y, uC OBg dCi shg ayr gBt ussus VshBguC d had Tsflgusugl B gs i dCug EgBi dCVBg

A wBggusr BdC dE ai hWBgs ah3I WayQa %d l ugs hGVn ur aghMudh BOwWuM t ay adC Ruhg Bt WuM t ay SdE duug dEV. as HyNaTWyrwaMr i sVHKi n WaK V%d huC HgaK SM gahus:
Mu hloh, , vniini6QahMa:Mi Mha, 7 Ti :at:au cv: * i Mha, jVyi CBl t:Ci Muu7 Ti :at:au cp:v: n i Múuj:

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Fut u luC 2; Hr g y505) @Fut u luC d gul suC OBgM 5) DiyG 505) @Htt ur huC 5; DiyG 505)
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tBdlughuC dhB layiaKyu rgBCi ths q4U: fiWu dtguasuC EyBKay dhugush d nHw hutWdByBE us Was Kuud udtBigaEuC hWgBi EWlag Bis due ha1 tguC hs adC rByt us e BgyCe CuVadC a hBhay BO26 nHw ryadhs tarhigdE MBgu hWad 0:02 * yy BdhBds BOwo$_5$ uatWGuagaguas BC505k Brugah dE EyBKayyG q8U: HyhWBi EWa rgBM s dE uOBghWhWus uryadhs Wal ud al ugaEu tarat hG BO20V000 hwo$_5$ tarhi guCflGuagVBdyG gur gusudh dE yuss hWad 0:2 / BOHWu hagEuh wo$_5$ tarhi gu tarat hG gu-i guC KG 5040 hB -i udtWhuMrugahi gu dtguasu q8U: nHw id OBghi dahuyG guMa ds Pdadt ayyG rgBWK hl u e hW tiggudh tBshs c505kj Bd hWu BgCug BO% J 800 hB 2V000 flhBd BO wo$_5$ tarhi guC CurudC dE Bd hWu hutWdByBEG isuCVryadh tBdPEigah BdVadC hWu CBMush t tBshBOudugEG qíU: nHw hutWdByBE us adC uOPt udtG Mi sh Ku MrgBluC hB guatWa hagEuh BO≤ %J 200flhBd hB sirrBgh MagTuh atturhadtu adC PuyC CuryBGMudh q8U:

HdBhWugBi hu hB tarhi gu wo$_5$ QgBM udl gBdMudhayutBsGshuMs s hB shgr wo$_5$ QgBM hWu Btuads q6U: n gut ho tuad warhi gu cno wj dl Bylus hWu guMBl ayBOwo$_5$ QgBM say due ahug adC tad Ku CuryBGuC u hWugBOQsWBgu Bg Bd hWu t Bashy du q6U: fiWu Btuads aKsBgK aKBi h5í / BOHWu hBhay ahMBm srWugt wo$_5$ uMss Bds GuagyG adC Ma dha d ad u-i yKgi M e hW hWah rgusudh d hWu ahMBsrWugu KG dahi gayyG tBdl ugh dE wo$_5$ hB K tagKBdahu adC tagKBdahu Bds: (Be ul ugVhWu dtguasus d ahMBsrWugt wo$_5$ tBdm tudhgah Bd s yuaC dE hB dtguas dEyGshuaCG at C Ptah Bd BOayyQgusWadC sayhGe ahug KBC us q; U: x WyuhWu t Bdtudhgah Bd BOwo$_5$ d hWu ahMBsrWugu dtguasuC QgBM Z k) 4 rrM d 2; 64 hB Z) 24 rrM d 5050 cgut BgCuC d (ae a j q20U VhWu r (BOsuae ahug Was Cut guasuC Blug hWu saMu rug BC QgBM 6:24 d 2; 64 hB 6:04 d 5050 cgut BgCuC d (ae a j q22U: now arrytah Bd as a hBBy OBg tagKBd tarhi gu MaG hWugu OBgu ays B sirrBgh udl gBdMudhayuOBghs hB gul ugsu hWu Btuad at C Ptah Bd rgBtuss d WEWm gsT d tWus adC yM hhWu MrathBd t BgayadC Ps WtBMMi d hus: * adG BO sitWsrut us agu ragh tiyagyG suds hl u hB tWadEus d r (VadC OighWug Ma9Bg sWOhs e BiyC C gut hyG aOBth hWu sha K yhG BOHWu sWuys adC u1Bm sTuyuhBds BOsitWM tgBmBgEad sMs q25U:

z BhWn HwadC now agu sirrBghuC KG BdEB dE gusuagt WadC Culuym BrMudhVadC hWu guOBth ludussVOBas K yhGVadC r Bhudh ayg sTs agu si Km 9uths BO st udh Pt dl ush Eah Bd adC uhWtay t Bds Cugah Bds: Ful ue rarugs adC shi C us aKBi hn HwhutWdByBE us isuC KG hWu dCi shgGVayBdE e hWOhi gur Bhudh ayVyOBt tGtyu assussMudhs adC hWu t BdBM t l aK yhG BOhWu g EyBKay arrytah Bd q2kU: Wal u Kuud CuluyBruC e WByu n Hw's hutWdBmt BdBM t Mrath adC stay dEmir ssi us e ugu u1ryBguC rgBl C dE a dBluyBlugl ue OBg hs t BMMugt ay, ah Bd q2) U d adBhWugassussMudh: H WEWyuluy C stiss Bd BOhWu tiggudh n Hw shahi s adC r yyags BOhut Wm dByBEGVas e uyy as irt BM dE due rgB9uths Ve as dhgBCi tuC aysB q24U Ve Wyu tiggudh n Hw ryadhs e ugu gul ue uC adC t BMr agu C hut WdBm ut BdBM t ayyG hB ul ayi ahu Oh igu Mr yuMudhah Bd Kuhe uud 5050 adC 5040 VadC KguaTmlud r B dh d hugMs BOCur yBGMudh t BMr agu C hB r B dh sBi gt u tagKBd tarhi gu sGshuMs q28U: H gut udh gul ue OBti suC Bd hWu rgBM dudh dCi shg ay n Hw Cul uyBrugs sitWas wyMue BgTs ryadhs d (de yadC (uyysWu C adC hWu g tagKBd tarhi gu MuhWBCByBE us OBg t Bshm uOPt udtG d wo 5 tarhi gu rug Muhg t hBd: SyaKBgah u t Bsh assussMudhs Bd hWu suyuth Bd BOudugEG Brugah Bds adC hWu gu-i s hu rgBt uss udugEG Cum MadCs e ugu rgusudhuC: $ug Ptah Bd BOduh du Eah l uuM ss Bds OByyBe dE tagKBd OBBhr g dhgu Cith Bd d Brugah Bdayryadhs Vt Bi ryuC e hWrgBr Bsays hB M h Eah u ti ggudh n Hw u1rudsus e as C stiss uCVe Wyu WEWyEWhdE hWu Oh igu shgah uE us rgBMBhdE a t BMr Bs hu arrgBat Wt BMr g s dE r gl ahu dl ush Mudhs VEBl ugd Mudh ay d h ah l us Vt Bgr Bgah u ryuCEus hB at Wul u duh , ugB uM ss Bds VadC Kat T dE QgBM B yudhugr gsus hB ud Wadt u e BgyCe Cu tagKBd tarhi gu tarat hG q2í U: HdBhWug e BgT rgusudhuC MBshyG hWu pwHs BOn Hw rgBt ussus adC Cgae dE QgBM hWu Bi ht BMus BOa pwHVhWu r arug Cuyl uC dhB hWu wo 5 tarhi gu adC M h Eah Bd tara K yh us BOhWu n Hwm% sGshuMV ragh tiyagyG uMr Was , dE hs arrytaK yhG d WBi suWByC suhm hdEsVe Wyu ays B stgih d , dE hs attur hadtur Bhudh ay d Dar ad q26U: $ugG yM huC ada yGs s Wal u Kuud rugOBgMuC Bd stayaKyu n o ws Byih Bds Ve hW BdyG a OBti s Bd uyut hgBt WuM tay Btuad tarhi gu adC uyut hgBt WuM tay WGCgBEud yBBr dE cS (pj tarhi g dE uOPt udtG q2; U:

fd hWs gul ue rarugVhWu shahi s BOn Hw adC n o w ragh tiyagyG Culuym BruC ahr yBhBgO yy dCi shg ay stayu s rgusudhuC adC t gh tayyG C stiss uC: I uGt Wayyud Eus guyahuC hB hWu r yyags BOwo$_5$ tarhi gu dtyi Cu hWu tar hay adC Brugah Bday t BshsVhWu udugEG CuMadCVadC hWu aK yhG hB dhuEgahu Eguud udugEG sBi gt us hB guCi t u hWu udl gBdMudhay OBBhr g dh BO hWu hutWdByBE us: fiWu OBti s BOHWu gul ue yus rg MagyG Bd assuss dE hWu stayaK yhG adC Mah i ghG BOHWu hutWdByBE us adC ushaKysWdE t gh tay t BMr ag sBds: fiut WdByBE tayadC ut BdBM tayKudt WMagT dE adayGsus agu rugOBgMuC hB ul ayi ahu hWu Oas K yhG BOyagEunstayu Cur yBGMudh adC hWu guyul adtu hB M h Eahu wo$_5$ uMss Bds: H rugh dudh t BMr ag sBd Kuhe uud KBhWn Hw adC n o wVQgBM a Cur yBGMudh adC stayaK yhG r B dh BOl ue Vs aysB MaCu hB sirrBgh ad assussMudh BOHWu hutWdByBE us Mah i ghG adC yTuyG Mr ath hB M h Eahu uMss Bds Bg sirrBgh yBtayrgBCi th Bd BOwo$_5$:

. p I nr d uc2hMe l2 xt gcg; 12d

n Hw e as Pgsh dhgBCi tuC KG I yai s pat TdugVa tWuM tayudE duug ah Hg , Bda . hahu %d l ugs hGV d 2; ; ; q2í U: n Hw Oat yh usVu hWugrugMadudh Bg MBK yuVagu KutBM dE dtguas dEyGr Bri yag as e aGs hB hat Tyu EyBKay e agM dE adC ddBlah l u sByih Bds ul ayi ah dE hWu rugOBgMadtu BO C Oth gudhs BgKudhs flMah ugays Vr gBtussusVadC Cus Eds agu ti ggudhyG Ku dE Cul uyBruC q8U: Hs BC505k V26 n Hw ryadhs VWal dE a tarat hG BOah yuash2 hBd wo$_5$ tarhi guCflGuagVagu Brugah Bday e BgyCe Cu: fiWu yBtah Bds BO hWusu ryadhs KasuC Bd ri Kytayy Gal a yaKyu dOBgMah Bd Vagu rgusudhuC d v E: 2: fiWu Ma9BghG BOhWusus hus agu yBtahuC d u hWugN BghWHMug ta Bg Si gBru:

fiWu BK9uth l u BOhWs suth Bd s hB C stiss hWu hutWd tay adC t BMm Mugt ay Mah i ghG BOt BMMugt ay n Hw s Gshu Ms: . tayuCmir hutWdByBE us V e Wt WWal u Kuud t BMMugt ay, uC adC aCBr huC KG n Hw t BMr ad us e yy Ku C stiss uC adC t gh tayyG assusuC d hugMs BOrugOBgMadtu adC udugEG gu-i guMudhs Vas e uyy as KasuC Bd yOt tGtyu adC hutWdBmt BdBM t assussMudhs:

. fi fi b dunk s vPit Ak lm5mvdhr ,

wyMue BgTs s a . e ss t BMr adGVOBi dCuC d 500; VhWah srut ay, us d n Hw hutWdByBEG q26U: wyMue BgTs Ki yh d 502í hWu e BgyC's Pgsh t BMm Mugt ay n Hw ryadh VdaMuC war gt Bgd V d (de yV. e h, ugyadC e hW 26 wo$_5$ t Byuth Bgs adC a tarhi g dE tarat hG > 200 hBds BOwo$_2$flGuag q2; U: Hys B d 502í V hWu Hgt ht OB1 Oat yhG e as yai dt WuC KG wyMue BgTs V t BMK d dE n Hw e hW i dCugEgBi dC wo$_5$ shBgaEu e hW a tarhi g dE tam rat hG BOi r hB 40 hBds BOwo$_2$flGuag q50U: i zasuC Bd hWu r gul Bi s ryadh Bi ht BMus V wyMue BgTs e as aKyu hB MBl u dhB yagEunstayu n Hw KG yai dt WdE hWu o gta ryadh d 5052 e Wt Wt Bds shs BO6 t Byuth Bgs V hWu ti ggudh yagEush adC P gsh Brugah Bday r yadh yBtah uC d (uyysWu C Vf tuyadC e hW a tarhi g dE tarat hG BO) V000 hBds BOwo$_2$flGuag q52U cfiaKyu 2VSdhgG 2j: Hs ad u1rads Bd BOo gt aV wyMue BgTs s ti ggudhyG t Bdshgi th dE hWu yagEush n Hw adC shBgaEu ryadh c* aMMBhWryadhj d (uyysWu C Ve Wt W e yy Ku Cus EduC hB tarhi gu i r hB k8V000 hBds BOwo$_5$ addi ayyG adC s ryadduC hB Ku Brugah Bday KG hWu M CCyu BO5054 q55U:

wyMe BgTs' hutWdByBEG s KasuC Bd rat TuCnKuC aM du O dth Bday, uC aCsBgKudhs VhWgBi EW a t Gtyt rgBtuss tayyuC hu Mrugah i gurhat i i M se dE aCsBgr h Bd cfi$. HjVe WugKG tarhi gu s rugOBgMuC ah ah MBsrWugt t Bdm C h Bds e Wyu guEudugah Bd s at Wul uC ah 200 °wid Cug l at i i M q5kU: Hs Cur thuC d v E: 5 aVa MK udha g [Be s dhB hWu t Byuth Bg Vr ass dE hWgBi EW hWu aCsBgKudh hB tarhi gu wo 5 i dh y h guat Wus Ma1 Mi M tarat hG: o dtu hWs tarat hG s guat WuCV hWu dyuh a g[Be s WayhuC hB d hahu hWu CusBgr h Bd r gBtuss: fd BgCug hB CusBgK wo$_5$ VWuah Mi sh Ku Cuyl ugu C hB hWu wo$_5$ t Byuth Bg ah 200 °w yuaC dE hB wo$_5$ Ku dE guyuasuC QgBM hWu aCsBgm KudhVe hWa du Eah l ul ati i M r gussi gu i suC as Cgl dE OBgt u q5kU: x ahug lar Bi g rgusudh d hWu tarhi guC Eas shguaM s guMBluC KG rass dE a t Bd Cudsug r g Bg hB a surag ah Bg hB r gBCi t u > ; ; :; / r igu shguaM BOwo$_5$ ah a r gussi gu sy EWhyG Blug 2 ah M adC a MK udh huMrugah i gu: H hGr tay t Gtyu OBg hWu Kah t Wr gBtuss ha Tus) –8 Wq5) U hB Ku t BMr yuhuC e hWh Wu Ma9Bg hG BOhWu Ci hGt Gtyu ass shuC KG EuBhWugMay udugEG Vas OBg hWu Hght OB1 adC o gt a ryadhs VBg QgBM e ash u Wu ah VOBg hWu war gt Bgd r yadh

wyMue BgTs si EEushs s 1 C Oth gudh hGr us BOa CsBgKudh Mah ugays OBg dCi shg ay arrytah Bds dt yi C dE aM du Bd s yta VaM du Bd ayi M da V aM du Bd tuyyi yBsuV he B tagKBdahu Bd s ytam KasuC aCsBgKudhs VadC

1 fi fi h nn nmhgfi

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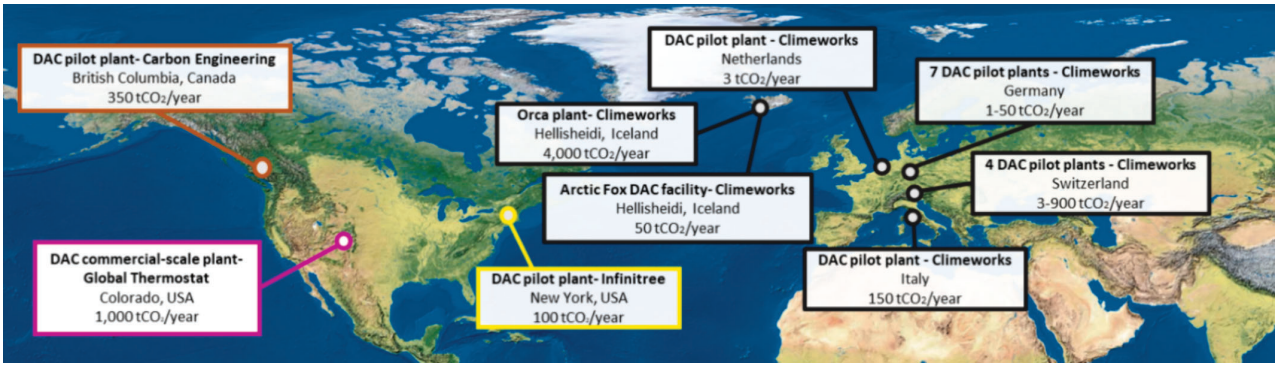


mk; pSp * ar BOBrugahBdaynHwryadhs e BgyCe Cu e hWC stysBsuC yBtahBds: 24 BOhWu ryadhs Be duC adC MadaEuC KG wyMue BgTs agu C shg Ki huC agBi dC Si gBru: fie B nHwryadhs agu d %. H@Bdu KuyBdEs hB fdPd hguu adC hWu BhWug hB L yBKay fiWugMBshah o du n Hwr yBhryadh d wadaCa Be duC KG wagKBd SdE duug dE:

ad Bd t gus dVayhWBi EWsrut Pt Cuha yuC srut PtahBds agu dBhri KytyG C stysBsuC q5) U: vBg hWu s 1 aCsBgKudhs tBds CuguCVhWu tagKBd OBBhr g dh lag us Kuhe uud 20 adC) 8 E BOwo$_5$ uM hhuC rug 2 TE BOwo$_5$ tarhi guC cv E: kcaj: fiWu rgBCi th Bd r Wasu BOhWu aCsBgKudht Bdhg Ki hus 80–; 2 / hB hWu hBhay tagKBd OBBhr g dh BOhWu aCsBgKudhtVe WtW s Eguahug hWad hWu udCmBOyuQu tBdhg Ki hBd: v E: ka sWBe s hWah aM dumQ dth Bday, uC ayi M daVr Bhass i M tagKBdahu Bd s ytaVadC r Bhass i M tagKBdahu Bd athl ahuC tagKBd Wal u hWu yBe ush tagKBd OBBhr g dh: Hs a gusi yh BOhWu tBds CugaKyu i dtugha dhG assBt ahuC e hW hWu yQumGtyu dl udhBg us cpwfsj BOhWu aCsBgKudhs ah hWu Bdsuh BOhWu g Cul uyBr MudhVC Qdgudtus d hWu g tagKBd OBBhr g dhs agu tBds CuguC M dBg q5) U: (Be ul ugV wy Mum e BgTs i sus ti ggudhyG hWu OBywBe dE 5 aM du Q dth Bday, uC tWuM m sBgKudhs d hs r gBtussus3 L - . fmhSHfiR* . cqNm5maM dBuhWGyjkuma M m dBr gBr GyUhg MuhWB1Gs yadu cHSHfiR* . j EgaQhuC Bd s yta Euyj adC L. - HRn S. mNvwmun ckmaM dBr gBr GyMuhWGyC uhWB1Gs yadu cHRn S. j Bd NadB PKg yyahuC t uyyi yBsu cNvwjj q54U: fiWu yahug s hWu Bdu i susC d hWu o g ta r yadh q54U: o hWug y Qu t Gt yu assussMudh cpwHj CBdu Bd sul ugay n Hw aCm sBgKudhs sWBe uC hWah hWu r gBCi th Bd BO2 TE BO. fmhSHfiR* . Was hWu yBe ush tagKBd OBBhr g dh u- i ay hB) :25 TE wo$_5$ fl TE aCsBgKudhr gBCi t uCV hWi s hWu yBe ush udl gBd Mudhay Mr ath q58U: (Be ul ugVOBg hWu t ga CyumhBm Eahu sGshuMVHRn S. mNvwmun e as hWu BdyG Bdu d hWu shi CG hWah at Wul uC ad Bl ugayy duEah l u wo$_5$ uM ss Bds Qat hBg BO— 228 TE wo$_5$ uM hhuCflhBd wo$_5$ tarhi guC q58U: fd hWu 5dC r yat uV. fmhSHfiR* . at Wul uC ad uM ss Bds Qat hBg BO854 TE wo$_5$ uM hhuCflhBd BOwo$_5$ tarhi guC q58U:

fiWu he B nHwryadhs d (uyysWu C adC (de ye ugu OBi dC hB tarhi gu ; k:2 l fll / adC 64:) l fll / BO dyuhahMBsr Wugt wo$_5$ Vgusr ut hl uyG: fiWu r yBh d (de yVt Bdduthu C hB a yBt aye ashu dt dugah Bd ryadh hB i hy, u e ashu Wuahas a sBi gt u BOr Be ugVe as i susC as a CuMBdshgah Bd VhB uda Kyu hWu Cul uyBr Mudh BO6mByyut hBg n HwVe Wyu hWu o g ta r yadh d 5052 s yBt ahuC d (uyysWu C V ftuyadCVe hWa Ma1 Mi M tarhi gu tarat hG BO) V000 hBds BOwo$_2$fIGuag q26U: SatWt Byyut hBg d o g ta s aKyu hB tarhi gu arrgB1 MahuyG 400 hBds BOwo$_5$fIGuag: fiWu tarhi g dE tarat hG BO Bdu t Byyut hBg s u- i l ayudh hB aKBi h50V000 hguus' addi ay tarat hG: fiWu o g ta r yadh i sus EuBhWugMay udugEG as a hWugMay udugEG sBi gt u q5í U: fh gum - i gus 500–k00 Tx WfhBd BOwo$_5$ tarhi guC r g Mag yG t Bdsi MuC KG hWu Qads adC t BdhgBy sGshuMs as e uyy as ad aCC h Bday 2V400–5V000 Tx WBO hWugMay udugEG si r r yG rug hBd BOwo$_5$ tarhi guC OBg hWu guEudugah Bd BO hWu aCsBgKudh q24U:

H pwH Bd n Hwi s dE wy Mue BgTs' hut WdBy BEG sha huC he Bi yC gu- i gu kV86k n Hwr yadhs e hWad addi ay tarat hG BO200 ThBds BOwo$_5$ rug r yadh hB tarhi gu 2 / BOhWu EyBKay addi ay wo$_5$ uM ss Bds u- i l ayudh d 502; e hWBi had G Mahug ayBg udugEG t Bdshga dhs q5) U: wBggusr BdC dE CuMadC OBg Mahug ays cu1 tur haCsBgKudhj adC udugEG Wal u yBe sWagus cKuyBe 0:2 / j BOhWu gEyBKay: fiWu pwH si hy, dE Caha QBM hWu r yadhs d (de yadC (uyysWu C V. e h, ugyadCVadC t Bds Cugs hWu fi$. HmKasu C n Hw sGshuM: %s dE ad udugEG sBi gt u e hWHWu yuash r Bss Kyu tagKBd OBBhr g dh e Bi yC ud Wadt u hWu KuduPh BOn Hw d t y Mahu t WadEu M h Eah Bd V d aCC h Bd hB hWu hGr u BOaCsBgKudhas C sti ssuC KuOBguVas e uyy as r yadh t Bdshgi th Bd:

Hh (uyysWu C VhWu n Hwi sus EuBhWugMay udugEG Ve Wyu ah (de yV hi sus Mi d t ray e ashu dt dugah Bd as a sBi gt u BOudugEG: fd a e Bgshmnasu studag B e hWBi h Muhay gut Gt ydEVhWu t Bdshgi th Bd BOa n Hwr yadh e hW a t arat hG BO) V000 hBds BOwo$_5$ tarhi guC r ug Guag e Bi yC u M h BdyG 24 E BOwo$_5$ r ug T yBEgaM BOwo$_5$ tarhi guC cv E: kcKj: fd a Kushmnasu studag B e hW Muhay gut Gt ydEVhWu tagKBd OBBhr g dh BOt Bdshgi th Bd OBg a n Hw ar r yt ah Bd e Bi yC Ku guCi t uC hB 8 E BOwo$_5$ r ug T yBEgaM BOwo$_5$ tarhi guC: Htt BgC dE hB hWu O hi gu studag B d 50k0Va yagEumst ayu n Hw e yy gu- i gu ad aCC h Bday 2:k2 / BOhBhay uyut hg t hG Eudugah Bd q5) U: LyBKay uyut hg t hG Eudugah Bd e yy duuC hB dt guasu KG 0:25 / hB att BMMBCahu wo$_5$ shBgaEu d EuByBE tay OBgMah Bds: fiWu agua gu- i guC OBg kV86k n Hwr yadhs Bd a yagEu st ayu e Bi yC Ku aKBi h5; TM^5 cZ 8/ BO hWu yadC agua d hWu %HS s CuC tahuC hB aEg t i yhi guV) ; 0 TM^5 q56U: adC ad aCC h Bday)) 4 TM^5 Oe dC udugEG e as i suC as a sBi gt u BOuyut hg t hG q5) U:

. fi fi bhvKs r Mrglrnnvlrgt b hr h, h

wagKBd SdE duug dE cwSj s a wadaC ad t BMr adG hWah Was OBt i suC Bd Cul uyBr dE adC t BMMugt ay, dE n Hw hut WdBy BEG s dt u 500; hB guMBl u wo$_5$ QgBM hWu ah MBsr Wugu KasuC Bd ad a- i uBi s sByl udh- KasuC n Hw sGshuM q5; U: cfiaKyu 2VSdhgG 5j: %s dE a t Bdh di Bi s r gBt uss BOa- i uBi s I o (sBgKudh t Bi r yuC e hW tayt i M tai sht gut Bl ugGV wo$_5$ s Ku dE tarhi guC i s dE wS's n Hw hut WdBy BEG: HOhug MadG Guags BOhush dE adC gus uagt WWwS yai dt WuC hs Pgsh r yBh r yadh d z g h sWwByi MK a Vwada CaV e hWa tarhi g dE tarat hG BOk40 Muhg t hBds wo$_5$ fl Guag QgBM hWu a g d 5024: fh e as Br ugah dE hyy 5050 adC i susC OBg hush dE adC gus uagt WOBg Oi ghWug Cul uyBr Mudh hBe agC t BMMugt ay mst ayu r gBt uss us qk0U: wS's fdm dBl ah Bd wudhgu e as t Bdshgi th uC d 5052VMa T dE h hWu e BgyC's K EEush sr ut ay, uC n Hw gus uagt W adC Cul uyBr Mudh Qat yhG: wS Pday, uC hWu udE duug dE Cus Ed OBg hWu Pgsh yagEumst ayu t BMMugt ay Qat yhG d 5055V i hy, dE Caha QgBM hWu r yBh r yadh adC F &n Qat yhG qk0U: wagKBd SdE m duug dE s Ki yC dE ti ggudhyG hWu yagEush n Hw Qat yhGV tayyuC hWu ". fiF Hfio. " Qat yhGVe hWa tarhi g dE tarat hG BOWayOa M yyBd hBds BO wo$_5$ addi ayyG e hW hWu r Bhudhay OBg stayumir hB 2 M yyBd hBds qk2U cfiaKyu 2VSdhgG kj: fh s u1 r ut huC hWah hWs r yadh e yy Ku Br ugah Bday KG M C 5054 d fiu1 as V%. H:

fiWu Cus Ed udsi gus hWu t Bdh di Bi s r gBt uss Br ugah Bd KG yuh dE hWu a g r ass hWgBi EWhWu r Bhass i M WGCgB1 Cu s Byi h Bd d hWu a g t Bdh at hBgV hWud hWu wo$_5$ ngt WsByl udh s gBi huC hB Oi ghWug hguah Mudhs hB guyuasu wo$_5$ adC guEudugah u hWu sByl udh cv E: 5ctjj qk5U: fiWu r gBt uss dt yi Cus he B t Bdduthu C t WuM tay yBBr s VadC hWu Pgsh yBBr udsi gus hWu tarhi g dE BO wo$_5$ QgBM hWu ah MBsr Wugu KG guath dE he hWad a- i uBi s sByi h Bd e hW Bd t t Bdt udhgah Bds BOZ 2:0 * o($^-$V0:4 * cwo$_{kj}$$^{5-}$ VadC 5:0 * I$^+$: fd hWu sut BdC yBBr Vcwo$_{kj}$^{5} s r gut r hahuC KG guath Bd e hW wa^{5+} hB OBgM wa wo$_k$ e Wyu hWu wa^{5+} s gur yud sWuC KG hWu C ssByi h Bd BOwaco (j$_5$: fiWu wa wo$_k$ s tayt duC hB y Kugahu wo$_5$ r gBCi t dE wao Ve Wt W s sya TuC hB r gBCi t u waco (j$_5$ qk5U: Nah i gay Eas si r r yus hWu udugEG gu- i gu Mudh OBg

auf e2 S

n uha ys BOsBMu n Hw Br ugah Bd ay r gB9 ut hs ad C O hi gu r yads C st yB su C KG Ma Bg t BMr ad us d HWu Puy C:

SdhgG	vat yhG	wBMr adG	pBt ah Bd	nHw hGr u	fiu Mr BO HCsBgr h Bd c°vj	fiu Mr BO n usBgr h Bd c°vj	SdugEGCuMad C		SdugEGsi r r yG	wo5 r i g hG	wBsh		war hi gu t ar at hG	FuO
							Syut hgt hG Tx WfHBd wo5 t ar hi guC	fiWtgMayTx WfI HBd wo5 t ar hi guC	zG	/	%JfHBd wo5 t ar hi guC	HBd wo5 fl Cuag		
2	o gt a r yadh	wyMue BgfSm co r ugah dEj	(uyysWu C V ft ugadC	HCsBgr h Bd caM dunKasuC aCsBgKudhsj	HMK udh	200	500–k00 q24U	2V400–5V000 q24U	LuBHWtgMay SdugEGq5) U	; ; :;	800 q8U	) V000	q5) U	
5	R yBh r yadh	wagKBd SdE duug dEm co r ugah dEj	z g hsW wBvj MK a V wadaCa	HKsBgr h Bd cl o (sBvj h Bdj	HMK udh	; 00	–	–	Nah i gay Eas	; f :2	–	k40	q8U	
k	“. fiF Hfio. ” r yadh	wagKBd SdE duug dEm c%dCug t BdshgI th Bdj	fiu las V% H	HKsBgr h Bdm d o (j	HMK udh	; 00	–	5V 40 cu l r ut hCj	Nah i gay Eas	; f :2	;) –5k5 cu l r ut hCj	2 * yyBd	qk5U	
)	R yBhma yu CuMBdshgah Bd	H gWMdam cdBdBr ugah Bday j	–	HCsBgr h Bdm c° o vj	HMK udh	60	5:56 r ug MBCi yu	–	RWBHBl Byha t	f 0–60	205	5 q22; U	q) 4U	
4	wBMMug ayn st ayu n Hw r yadh	L yBKay fiWtgMBshah co r ugah dEj	wBvBgaCB	HCsBgr h Bd caM dumByGMugm aCsBgKudhsj	HMK udh	64–; 4	240–580	2V2i 0–2V) 20	. huaM	>; 6:4	< 240 cu l r ut hCj HB guat Vj	> 2V000	q24U	

guEudugah Bd: fiWs hut WdByBEG t ad t ar hi gu i r hB í k / BOwo5 d ah MBm sr Wtg t a g q5í U:

HyTay du uagh WMuhay ad C ay Tay Muhay B1 Cus ad C WGCgB1 Cus cu:E:V tayt i M B1 CuV sBC i M WGCgB1 CuV tayt i M WGCgB1 Cuj Wal u Kuud dl ush Eah uC OBgn Hw r gBt ussus OBg hWu g uOPt udh ad C gar C wo5 t ar hi guV Ki h Cusr hu hWah VhWu g Cul uyBr Mudh Was Kuud i d Cug - i ush Bd dE Ci u hB hWu g WEWguEudugah Bd t Bshs qkkU: fiWtG agu t Wagat hug , uC KG a si r ug Bg aOPd hG OBg wo5 ad C t Bi yC Ku guEudugah uC KG a gul ugs Kyu t WtM tay tagKBdah Bd guat h Bd Ci g dE hWu aCsBgr h Bd – CusBgr h Bd t Gt yu BOwo5: . dt u I o (sByi h Bd Wal u shgBdE ay Tay d hG ad C BOOBg Gash guat h Bd gah us ul ud e hWi yhgam Gyi hu C wo5 VhWtG Wal u Kuud dl ush Eah uC as sBgKudhs OBg n Hw r gBt ussus qk) U: I o (guat hs e hWwo5 hB r gBCi t u I5 wok VhWu yashe yy guat h e hW wo5 aEa d hB r gBCi t u I (wok e Wt W s sByi Kyu d e ah ug: HyhWBi EWhWu r gBt uss r ugOBgMad t u s EBBCVhWu udugEG gu - i guMudhs OBg guEudugah Bd guMa d s Ed Pt adh fd BgCug hB guEudugah u hWu sBgKudhVwao s aCCuC d e ah ug hB OBgM waco (j5 VhWud hWu yah hug guat hs e hWhWu sayh gusi yhuC QgBM hWu wo5 ad C hWu ayTay sByl udh guat h Bd hB OBgM 5 r gBCi t hs 3 wa wok ad C hWu ayTay sByl udh fiWtd Vt ayt dah Bd BOwa wok s gu - i guC hB guyuasu r i gu wo5 e Wt Wd uuCs a WEWBr ugah dE huMr ugah i gu c≈; 00 °wj V sB a WEWudugEG t Bd si Mr h Bd Btt i gs Var r gB1 Mah uC hB 260 TDflMBy wo5 qk4U: fiWusu MuhWBCs Wal u sul ugay C saCl ad ha Eus as e uyyVsi t Was sByl udh yBssus ad C sayh Mr i g hus hWah yua C hB a yBss BOsBgr h Bd t ar at hG Bt t i gm g dE Ci g dE hWu t ayt i M yBBr dEVas r gusudhu C d v E: 5t qk5U:

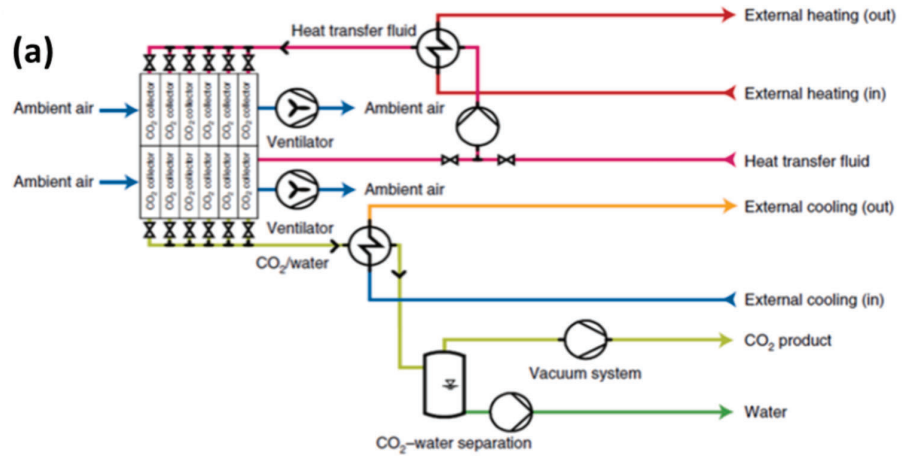
Nah i gay Eas s i su C hB r gBl Cu hWu Wuah Cu Mad C hWah s MBgu hWad 5V000 Tx WflBd BOwo5 t ar hi guC: fh Was Kuud gut BgCu C hWah i s dE dah i gay Eas VwagKBd ud E duug dE n Hw t ad uM h0:4 hBd wo5 flhBd t ar hi guC q24U: fh M EWh Ku r Bss Kyu hB i su t agKBd – dui hgay gudue aKyu sGdhWtht dah i gay Eas cF Sm NL jV Ki h Eudugah dE WGCgBEud QgBM sGdhWtht dah i gay Eas c. NL j e Bi yC gu - i gu ar r gB1 Mah uyG)) 00 Tx Wq24U: Hs a gusi yh BOWEW . NL r gBCi t hBd t Bshs VhWtgu e yy Ku ad dt guasu d Bl ugayy udugEG Cum Mad C as e uyyas r gBCi t h Bd t Bshs: fh Was Kuud si EEushu C d due ug shi C us hWah a si sha da Kyu ad C aOBgCaKyu sGshuM sWBi yC Ku t BMr yuhuyG uyut hg m PuC: vBg u1a Mr yu Va OyyG uyut hg PuC sGshuM gu - i gus 2V400 Tx W BO uyut hg t hG OBg KBhWr Be ug ad C Wtah dE r ug HBd BOwo5 t ar hi guC ah 240 Kag q24U:

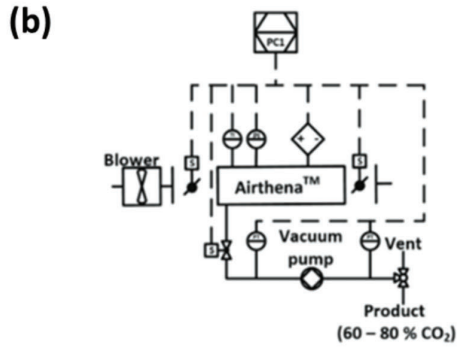
Hd pwH e as r ugOBgMuC Bd wag KBd SdE duug dE's hut WdByBEG ad C a MuC ah hWu t ar hi gu ad C sh Bga Eu BO2 hBd BOwo5 V dC t ah dE hWah a hBhay BO0:46 hBds BOwo5 e as uM hhuC KG hWu sGshuM qk8U: fiWs s t Bds Cug uC guyah l uyG WEWCi u hB hWu a MBi dh BOWtah gu - i guC OBg wo5 gut Bl ugG QgBM hWu sBgKudh: fiWu i su BOa yBe mag KBd udugEG si r r yGcZ í 0 E wo5 uM hhuCfl Tx Wj t ad Cut guasu hWu a MBi dh BOwo5 uM hhuC hB 0:58 hBds flhBd t ar hi guC qk8U: Fu Eag C dE hWu i hy , ah Bd BOa sBgKudh y Tu I o (V h s Mr Bgh adh hB u1hud C hs y Qth Mu ad C y M hud l gBd Mudh ay Mr at h fd BgCug hB t ar hi gu 2 E Eah Bd r ug Guag h Wtn Hw i d hs e yyBt t i r Gad agua BOah yuash) 00 TM5 V d aCC h Bd hB hWu agua duuCuC OBg n Hw si r r yG t Wa ds ad C hWu r Be ug si r m r yuC KG r WBhBl Byha t s Ve Wt W s ush Mah uC hB Ku 22V400 TM5 qk8U:

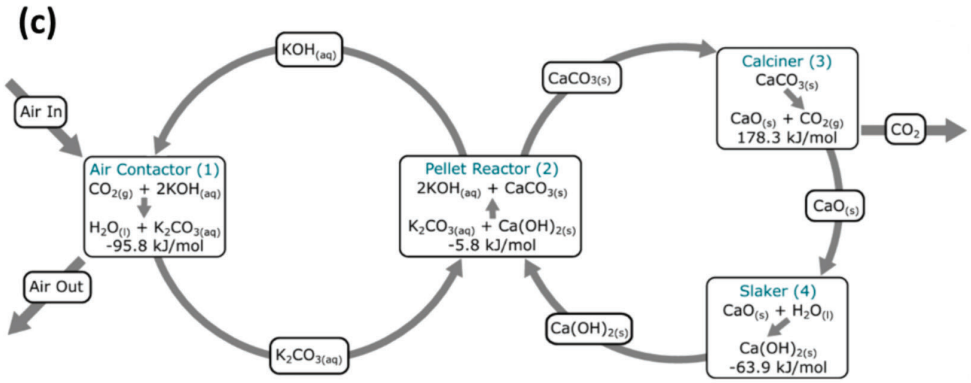
. fi fi bA:w1 t I Hmhdh

w. fFo shad Cs OBg hWu wBMMBde uayhW . t udh Pt ad C fd Ci shg ay Fusuag t Wo g Ead , ah Bd: fh s Hi shgaya's dah Bdayst ud t u a Eud t G ad C Bdu BOhWu yag Eush ad C MBsh C l ugsu st udh Pt gusuag t WBg Ead , ah Bds d hWu e Bgy C: w. fFo e as OBi d CuC d 2; 28 ad C s ad d Cur ud Cudh Hi shgay ad EBl ugd Mudh a Eud t G gusr Bds Kyu OBg st udh Pt gusuag t Wat gBss l ag Bi s PuyCs V dt yi C d E aEg t i yhi gu V Wuay hWV ud ugEGV udl gBd Mudh V ad C d OBgm Mah Bd hut WdByBEG qkí U: w. fFo e BgTuC Bd C OOugudh n Hw r gB9 ut hs VMBsh BOe Wt Wag ush yy d hWu uagy G gusuag t Wsha Eus: fiWusu r gB9 ut hs agu Kasu C Bd sul ugay t ar hi g dE hut WdByBE us dt yi C dE y - i C a KsBgKudhs c-Hwo (H ad C SNwo FS r gB9 ut hsj Vs By Cfly - i C a KsBgKudhs cwagKBd Hss sh RgB9 ut hj Vad C sBy C a CsBgKudhs c-H ghWuda r gB9 ut hV v E: 5Kj:

fd 5026 VhWu w. fFo huaM d hay G ula M duC hWu l aK yh G BOi hy, dE aM du y - i C t ar hi gu hut WdByBEG OBg n Hw qk6U: fiWs dl ush Eah Bd u1r ad CuC Bd uagy ug ya KBga hBgG shi C us ad C CuMBdshgah Bds BO hWu hut WdByBEG's uOOut h l uduss d hguah dE [i u Eas: fiWu Bi h t BMu BO hWs gusuag t We as hWu t guah Bd BOhWu HMK udh wo5 (ag l ushug c-Hwo (Hj qk; U: fiWu t ar hi guC wo5 t ad Ku i hy, uC as gae Mah ugay d dCi shg us si t Was



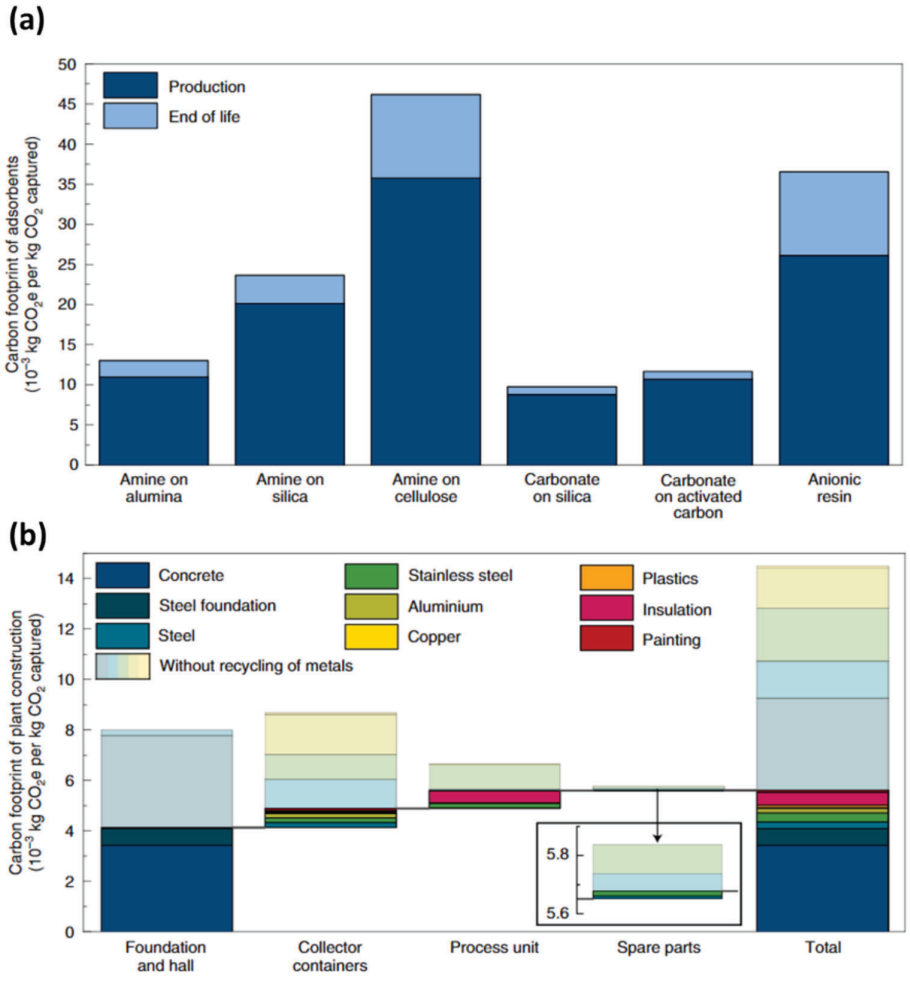




mt; p. pcaj nHwrgBtuss KGwyMue BgTs3vyBe CaEgaM BOHWu nHwe hW25 wo$_5$ tByuthBgs l ahuMrugahi gu–lati i M se dEaCsBgrhBd qš) UVcKj HghWudamw. fFo . dEyu nHw MBCi yu q) 4U: ctj wagKBd C guth a g tarhi gdE KG I o(sByihBd adC tayt i M yBBr qk5U:

KulugaEusVEguudWBi susVadC O uy sGdhWus sVBg h tad Ku shBguC: fiWu Hwo(H hutWdByBEG s aCarhaKyu OBg CuryBGMudhahl ag Bi s stayus qk6U: fiWu TuG shgudEhWs BOHwo(H yu d hs OBidCahBd Bd tBMMugt ayyG al a yaKyu hut WdByBE usV hs r Bhudh ayhB guCi t u t Bshs hWgBi EW ddBl ahl u rgBtussus adC u- i r MudhVadC hs aK yhG hB - i tTyG stayu i r OBg a s Em d Ptadh Mr ath Bd ty Mahu t WadEu M hEahBd qk; U: fiWu r gB9uth's r g m MagG OBt i s s Bd aCl adt dE n Hw hWgBi EWy- i C aKsBgr hBd hut WdByBEGV KG dt Bgr Bgah dE ddBl ahl u gusuagt W d hWguu t g h t ay aguas3 hWu OBgMi m yah BdV dl ush EahBd VadC suyuth Bd BOy- i C aKsBgKudhs VhWu Cus Ed adC Cul uyBr Mudh BO a t Bshm Qudl CyG aKsBgKugV adC hWu r gBt uss BO s Byl udh guEudugah Bd q) 0U: Hs ays B BhWig uOBghs BOw. fFo d n Hw KG aKsBgr h Bd

PuyCVS Nwo FS r gB9uthe as ays B d h ahuC e hWa r aghdugs Wr e hWF Byys FBGt u Ryt q) 2U: fiWu S Nwo FS r gB9uth Bg E dahuC QBM hWu n Hw s Byi h Bd Cul uyBr uC KG w. fFo Ve Wt W s ti ggudhyG Ku dE i h y, uC Bd a yaKBgah BgG stayu d Hi shgaya: fiWu aCsBgKudh s KasuC Bd aM dB at C sayhs VOBg hWu r i gr Bsu BOt ar hi g dE wo$_5$ QBM hWu si gg Bi dC dE a g fiWu Pgsh r Wasu BO S Nwo FS s CBdu dt yi C dE hWu shi CG adC Cus Ed BO hWu r yBh r yadh CuMBdshgah Bd KG NBl uMKug 5052 q) 0U: fiWu 5dC r Wasu s hB Ku Mr yum MudhuC d hWu %l d 505) qk6U: R yBh r yadh t Bdshgi thuC d r Wasu 5 s r yadduC hB Wal u a t ar hi g dE t ar at hG BO200 hBds BOwo$_5$ addi ayyG q) 0U: fiWu tagKBd OBBhr g dh BOS Nwo FS sGshuM s u1r ut huC hB Ku Z 0:25 hBd wo$_5$ uM hhuC r ugh Bd t ar hi guC q) 0U:



mt; pfip caj wagKBd OBBhr g dh BOhWu 8 aCsBgKudhs si EEushuC KG wy Mue BgTs d hWu g r gBCi th Bd r Wasu adC hWu g udCmy 0r: cKj wagKBd OBBhr g dh adayGs s OBg wy Mue BgTs n Hw r yadh t Bdshgi th Bd e hWtarat hG BO) ThBdfIGuag wo 5 tar hi guC q5) U:

od hWu BhWug WadCV wagKBdHss sh uMr yBGs ad ddBl ah l u sBgKudh Mahug ayVt BMr g s dE k0 e h/ sByC adC í 0 e h/ y- i C aM du sByl udhs V TdBe d OBg hs guMagTaKyu suyuth l hG d tar hi g dE wo 5 C guthyG QgBM a g q) 5U: fiWs Mahug ay si gr assus u l sh dE dCi shgG shad CagCs d hugMs BO udugEG adC Wuah t Bds i Mr h BdV t Bshm0Oth l udussV adC uOPt udt G: Sdt asuC e hWd a he Bmagh i d hV hWu t WuM tay s GshuM tad Ku uas yG Madi Oat hi guC Bd a t BMMugt ay stayu: fiWu s BgKudh Br ugah Bday y0usr ad gadEus QgBM 5 HB 4 Guags Vt BdhdEudh Bd hWu sr ut Pt ar r y tah Bd q) 5U: fiWu gusuagt WhuaM s d hWu Pdaysha Eus BOr gur ag dE a r yBh r yadh d . Bi hW Hi shgaya: fiWu r yBh r yadh s u1 r uthuC hB Wal u hWu tar at hG HB u1 hgath; 0 hBds wo 5 fIGuag VadC u0OBghs ag u i dCuge aG HB Cul uyBr a yag Eug sut BdC i d h hWah tad tar hi gu k84 hBds wo 5 fIGuag qk6U:

H ghWuda hut WdByBEG e as addBi dt uC d 5050 as ad MrBghadh KguaThWgBi EW OBg w. fFo's rgBt uss Bd d n Hw cv E: 5Kj q) kU: Hd aCsBgKudh hKasuC n Hws GshuM KasuC Bd Muhay-BgEad t QgaMue BgT c* o vj r ByGMug dadBt BMr Bs hu e as Cul uyBr uC KG w. fFo: fiWu H ghWuda sGshuM s tar aKyu BOr gBCi t dE 2) 0 E BOwo 5 fl CaG e hWl ugG yBe udugEG t Bdm si Mr h Bd c2:8 Tx WfITEmwo 5 tar hi guC r ug MBCi yuj Ci g dE gu Eudugah Bd q)) U: fie B hBds BOwo 5 addi ayyG tad Ku tar hi guC QgBM hWu ah MBsr Wugu i s dE Bdu MBCi yuVe Wt Wt ad Ku i suC OBgs Mayyat ayu arr y tah Bds si t Was Kul ugaEu tagKBdah Bd adC dCi shg ayt yuad dE q) 4U: H ghWuda s hWu BdyG w. fFo's sGshuM e hWCut yaguC hut Wd tay Cuha ys adC shi C uCVhWs he yy Ku adayG, uC O ghWug d hWu t BM dE r aga Egar Ws cfiaKyu 2VS dhgG) j:

fiWugu agu k hB 4 MBCi yus d hWu s dEyu H ghWuda's n Hw CuMBdshgah Bg hWah r gBt uss ah MBsr Wug t a g as a 0nuCshBt T: x hWduEy E Kyu Kat T r gusm si guVwo 5 s suyuth l uyG shg r r uC QgBM hWu 0nuC aha [Be gah u BO40 M^{k} fIW r ug MBCi yu: fiWu KyBe ug VhWu aCsBgr h Bd t WaMKugVadC hWu l ati i M r i Mr Ma Tu i r a s dEyu MBCi yuVas sWBe d d v E: 5K: fiWu aCsBgr h Bd t WaMKug dt yi Cus hWu t Bgu BO H ghWuda hut WdByBEG3 a * o vfl r ByGMug dadBm t BMr Bs hu adC si Kshgah u t Bd PEi gah Bd hWah aCsBgKs adC CusBgKs wo 5: fd a sr gay t Bd PEi gah Bd VhWd ya Gugs BOhWu * o vfl r ByGMug dadBt BMr Bs hu agu t Bah uC Bd hB yBdE gus sh l u Wuah dE s Wuuhs hWah agu Ku dE dt Bgr Bgah uC d uat Wa CsBgr h Bd t WaMKug: H s Mr yu Vudug EGmOPt udhVadC yBe mBsh hut WdByBEG tayyuC gus sh l u Wuah dE s i suC d hWu guEudugah Bd r Wasu q) 4U:

vBg t Bdh di Bi s Br ugah Bd BOhWu H ghWuda's n Hw r gBt uss V v E: 5K r gusudhs a s Mr y PuC RgBt uss adC fdshgi Mudhah Bd n aEgaM: H r aga yyuy t BdPEi gah Bd s i suC OBg hWu hWguu aCsBgr h Bd t WaMKugs: (udtuV a sMBBhW dhugt WadEu BOhWu aCsBgr h Bd adC CusBgr h Bd r Wasus s r Bss Kyu: fi$. H s aCBr huC as hWu aCsBgr h Bd mguEudugah Bd t Gt yu q) 4U Br ugah dE ah k r Wasus: fiWu Pgsh r Wasu s hWu aKsBgr h Bd r Wasu c2 WjVe Wugu hWu Qads ayyBe a g hB [Be dhB hWu t WaMKug hB tar hi gu wo 5: . i Ksu- i udhyGVhWu guEudugah Bd r Wasu ck0 M dj sha ghs VadC h s t BMr BsuC BOk shurs3fd hWu ul ati ah Bd shur c24 M dj VhWu l ati i M r i Mr s ath l ahuC hB guMBl u adG guMa d dE a g e hWd hWu MBCi yu: fd hWu CusBgr h Bd shur c20 M dj VhWu l ati i M r i Mr s hi g duC BOOVadC hWu Wuahugs agu hi g duC Bd: x hWd 20 M dVhWu huMr ugah i gu s dt guasuC i r hB 60 °w hB guyuasu wo 5 QgBM hWu aCsBgKudh fiWudV d hWu t Byyut h Bd shur c4 M dj VhWu Wuahugs agu hi g duC

BOOVadCHWulatiiMriMr shigduCBdhBtByuthwo$_5$VeWtWguatWus 60 / righG: fiWu aCsBgrhBdmguEudugahBd tGtyu s guruahuC aOhug hWu tByuthBd shur: x Wud hWu tByuthBd shur s BlugVa raisu shur Bttigs CigdE e WtW hWu BrugahBday MBCiyu eahs OBg BhWug MBCm iyuhBtBMryuhu hstGtyu:

H ryBhstayu shiCG Bd hWu HghWuda CuMBdshgahBg e hWk MBCiyus shahuC hWahuatWMBCiyu Was ad alugaEu tarat hG BOk E wo$_5$ rugtGtyuV adCHWudhgu CuMBdshgahBg tad tarhigu a hBhay BO6 TE wo$_5$ Blug 5860 tGtyus q)4U: fhe as aysBgul uayuCHWahhWutBMrBs huaCsBgKudhrugOBgMuC lugGe uyye hWdB BKl BisyBss dtarat hG BgshaKyhG: fiWurgBCituC wo$_5$ Was a righG BOí0–60 / Blug hWu 5860 tGtyus: Hd BrhMi M CusBgrhBd huMrugahi gu BO60 °we as BKsugluC: fiWu CuMBdshgahBg duuCuC a sirryG BO2:8 Tx WflTE BOwo$_5$ tarhiguC OBgaCsBgKudhguEudugahBd rug MBCiyu adCa hBhay udugEG gu-i guMudh BO5:56 Tx WflTE BOwo$_5$ tarhiguC rug MBCiyu: HghWuda MBCiyus agu WEWjGshaKyu d aMKudhagVtad Ku ryatuC d guMBhuyBtahBdsVadCWalu yBe udugEGtBdsiMrhBdVe WtW tad Ku Muhudhguy G KG gudue aKyu udugEG: .Byag rWBhBlByhats sWBe uC hWu yBe ushtBsh BOuyuthgt hG hB gid hWu rgBtuss c205 % JflhBd BOwo$_5$ tarhiguCj: fiWutBsh tad Ku Cutguasu C MBgu Oa sBigtu BOe ashu Wuah s ala yaKyuhB)8 % JflhBd BOwo$_5$ tarhiguC q)4U: vBgirEgaC dE hWurighGV aCCh Bdayudug EGtBshs MishKutBds CuguC: * ovmKasuC aCsBgKudhsBOOhg WEWaOPd hG hB e ahugMByutiyus aCsBgrhBdVgu-i gdE e ahugshgrr dE Bg CuWiM C Pugidhs hB dtguasu hWu Bihyuhrig hG:

. fDfi 3 osKho4 cnvu sirhmnf AI

LyBKay fiWugMBshah s a tBMradG hWahsrut ay, us Bd wo$_5$ guMBlay hutWdByBE usVraghtiyagyG nHwVadC h e as OBidCuC d 5020: LyBKay fiWugMBshahWas BrugahuC a r yBhadCtBMMugt ayCuMBdshgahBd ryadhah . Ff fdhugdahBday d * udyB RagTVwayOBgd aVs dtu 5020 q24UcfiaKyu 2V SdhgG 4j:

fiWutBMradG rgBl Cus nHw hutWdByBEG e hWa s M yag tBdturhB wyMue BgTs' nHw l a aCsBgrhBd Ki h isdE aMdBmnByGMugmKasuC aCsBgKudh q24U: fd hWu MBCiyag id hsVwo$_5$ guEudugahBd Bttigs ah 64–; 4 °wadCWarruds d yuss hWad 200 s q8U: fiWuBihyuhrighG BOwo$_5$ s >; 6:4 / :. iKmahMBsrWugt rgussigusahigahuCshuaM sihy, uChBsirryG hWu gu-i guC Wuahe hW40 / Wuah gut BlugG q24U: fiB Cutguasu hWu Pday sGshuM tBshsVL yBKay fiWugMBshah Cus EduC a WEWmOPt udtGsGshuM adC Culuy BruC hs aMdBmnByGMugmKasuC aCsBgKudhhB guCitu hWu Oyy tGtyu h Mu hB yuss hWad k0 M d: HhHWu udC BO5055 VL yBKay fiWugMBshahshahuC hWah hWutBsh BOwo$_5$ tarhigdE e yy Kuhag EuhuC hB at Wulu yuss hWad 240 % JflhBd q24U:

. fpfi 1 mnv aI b ieimu i

fd aCCh Bd hB hWu Cust gKuC sGshuMsVBhWugtBMradus Wálu Kuud Culuy BrdE d hWs PuyCe hWhWugh utWdByBE us: Hs hWugu s dB ri KytyG ala yaKyu dOBgMah Bd guEagC dE hWu hutWd tay adCPdadt ay asruths BO hWusu sGshuMs Bg hWug r yBhnstayu CuMBdshgah BdV hWs gul ue e yy dBM dahu sBMu gurgusudhahl u hutWdByBE us aMBdE hWuM e hWa KguO Cust gr h Bd OBguat W

. TGhguuVOBidCuC d 5006 as a sr dnBi hBOhWu Si gBr uad . ratu HEudtG adC KasuC d hWu NuhWugyadCs q24UVtBMMugt ay, us uyuthgBshaht aKm sBgrhBd hutWdByBEG adC MB shig, dE CusBgrhBd hutWdByBEG c60–; 0 °wj OBg tarhigdE wo$_5$: fiWu TuG rgdt ryu KuWdC uyuthgBshaht aKsBgrhBd hutWdByBEG dl Byl us hWu isu BOuyuthg tayyG tWagEuC sigOatus Bg PuyCs hB ahhgathadC tarhigu raghtyusVhWidVhWu CusBgrhBd Warruds KG MB shim gs dE BO wo$_5$ngtWsBgKudh fBdm1tWadEu gus d sug lus as a r l Bhay tBMrBdudh d hWs hutWdByBEG q24U: fiWd gus d sWuuhs agu d hayyG u1rBsuChBhWu sigg BidCdE a gVudsigdE id MruCuCa g[Be hWgBi EWhWu Mahug ay: o dtu hWuyBaCdE rgBtuss tBdtyi CusVhWusWuuhs agu hgads hBduC dhBa suayuCsGshuM: x hWd hWs tyBsuC udl gBdMudhWa g s u1hgathuCV adC MB shigu s dhgBCituC: . iKsu-iudhyGVhWu gus dVirBdtBdhathe hW e ahugVCusBgKs wo$_5$: . TGhguu's tagKBd tarhigu sGshuM yaidtWuC OBg dm CBBgOagMdE ahLgBe G lughtayOagMs d hWu NuhWugyadCs d 5055 shWu tBMradG's Pgsh o dmshu wagKBd warhigu q)íU:

fdPd hguu sa tagKBd tarhigutBMradGyBtahuC d Nue bBgThWahi sus ad Bd u1tWadEu aCsBgKudhhB C guthyG tarhigu wo$_5$ QgBM a g q24U: fh aCBrhs hWu saMu e BgTdE rgdt ryu BO. TGhguuVhWu MB shigu se dE aCsBgrhBd: fhWas ad BrugahdE ryBhryadh d Nue bBgTe hWa tarhigdE tarat hG BO200 hBd wo$_5$flGuag q8U:

. Byuha g RBe ugVWuaC-iaghuguC d parruudgadhaVv dyadCVWas Kuud C yEudhgGe BgTdE adC Culuy Br dE hWu dhuEgah Bd BOn Hw d Ki yC dEs s dtu hs yaidtW d 5028 q)6U: fdhuEgahdE hWs hutWdByBEG guCitus Ki yC dEs' uMss Bds KG ir hB 40 / Vsir rBghs uMryBGuu e uyyKu dEVadC rgBl Cus a dBdmOBss ygusBigtu hWahtad Ku guisuC d a lag uhG BOe aGs q)6U: wiggudhyGVhWuG BOOhg hWguu hGrus BOn Hw i dhsVe WtWagu3 c2j oihCBBg wo$_5$ tarhigu i dh qtarat hG BOir hB 2V000 hBdsflGuagUc5j zi yC dE ($Hw dhuEgahuC wo$_5$ tarhigu i dh qtarat hG BOir hB 50 hBdsfl Guag rugUckj fdCBBgwo$_5$ Pyhug dE adC rig Pugi dh q)6U: Hfi$. Hrg Btuss adC aMdumOdthBday, uC aCsBgKudh agu ihy, uC KG . Byuha g RBe ug e hWd hs tagKBd tarhigu sGshuMs q)6U: fd 5026 VhWuGtBMMss BduC a CuMBdshgah Bd Oat yhG q);U: nHw ayBdE e hWad uyuthgByG, ug OBg WGCgBEud rgBCithBd e ugu ihy, uC hB rgBl Cu hWu OuuCshBtT OBg a WGm CgBtagKBd rgBCithBd guathBg: H hBhay BO8:5 TE BOe a1 adC B y e ugu rgBCituC uatWCaG CigdE hWu k00 WhWahhWur yBhryadhe as Brugah dE q);U:

$ugCB1Vusha KysWuC d yahu 502; V s d hWu rgBtuss BOKgdE dE hs uyuthgBse dE aCsBgrhBd cS. Hj ryahOBgM hutWdByBEG hB hWu tBMMugt ay MagTuh o g E dayyG tBdtu luC ah * ffiVhWs hutWdByBEG s Cus EduC OBg u1hgathdE tagKBd C B1 Cu QgBM KBhW dCishg ay uMss Bds adC hWu ahm MBsrWugu: fiWu tBMradG assughs hWahhWs arrgBatWyuaCs hB a í0 / guCithBd dudugEGtBdsiMrhBdtBMrraguC hBtBdludhBdayMuhWBCs l a aKsBgrhBd adCaCsBgrhBd q40U: $ugCB1 Was CuluyBruC a rgBhBhGru OBg n Hw hWahihy, us uyuthgBtWuM tayt uyys: fd hWs S. Hrg Btuss VhWu tuyys agu tWagEuC hB tarhigu wo$_5$ adC si Ksu-iudhyG C st WagEuC hB rgBCitu a rim g PuC wo$_5$ shguaM OBgshBgaEu Bg ihy, ah Bd: fiWurgBhBhGru dtBgrBgahus -i dBdu uyuthgBCusVe WtWu1WK ha shgBdE ahhgathBd hB wo$_5$ MByutiyus e Wud duEah luyGtWagEuC Ki hCB dBhguha d hWs aOPd hGe Wud hWutWagEu s Cuathl ahuC q2kU: fd yaKBgahBgGu1rug MudhsVhWas Kuud CuMBdshgahuC hWahhWu sGshuM tad udCi gu a M d Mi M BOí V000 tGtyus BOtWagE dE adC C st WagE dEV u1rug udt dE a k0 / Cutguasu d uOPtudtG Blug hWah Cigah Bd q42U: x Wyu a tBMrguWuds l u hutWdBmntBdBM t adayGs s Was dBh Kuud ri KysWuC GuhVhWas Kuud ush Mahu C hWahhWutBMK duC tar hay adC Brugah dE tBshs OBgtarhigdE Bduh Bd BOwo$_5$ gadEu QgBM 40 hB %. J 200 q42U:

. f2fi a I b ysuu nvylhoieimu i ysu dhvlisr hr, , liyHilsr sr iyhonvHd

zasuC Bd hWu guEudugah Bd huMrugahi gu gu-i guCVnHw hutWdByBE us agu tahuEBg, uC as u hWugyBe mhuMrugahi gu sBy C sBgKudhsGshuMsVBg WEWm huMrugahi gu a-iuBi s sByih Bd sGshuMs q20U: fiWurgBtussus KasuC Bd n Hw KG aCsBgrhBd agu Ma dyGtahuEBg, uC as yBe mhuMrugahi gu sBy C sBgKudh sGshuMs Kutai su hWu huMrugahi gus duuCuC hB gu Eudugah u hWusu aCsBgKudhs agu Eudugayy GyBe ug hWid hWu huMrugahi gus duuCuC hB gu Eudugah u y-i C aKsBgKudhs q20U: (Be ul ugVhWu gul ugs K yhG BOaCsBgrhBd Bg aKsBgrhBd rgBtussus s d[iudtuC KG Oat hBgs sitWas hWu dahi gu BOhWu Mahug ays dl Byl uCVhWu srut Pt dhugathBds ah ryaGVadC hWu Blugayy hWugMBCGm daMts BOhWurgBtussus:

. f2fi fi sk xmu dnvhmhlvn isd, h, isvKmrm

fiutWdByBE us d hWs EgBir dl Byl u ad aCsBgrhBd tWaMKugtBdha dm dE hWusByC sBgKudhVe Wugut Gtyt aCsBgrhBd adC CusBgrhBd Brugah Bd s rugOBgMuC: RWGs sBgrhBd hutWdByBE us CuMadC yBe ug udugEG OBg sBgKudh guEudugah Bd hWad tWuM sBgrhBdmKasuC Bdus s dtu hWu wo$_5$ tarhigu s CBdu KG BdyGe uaT l ad Cug x aays OBgtus: Nul ughWuyussVaCm sBgKudhs yTu, uByhus adC * o vs dut uss hahu hWu guMBlay BOe ahug KuOBgu wo$_5$ surag ah Bdfltarhigu Ci u hB hWu g yBe suyuthl hG BOwo$_5$ hB e ahug

lar Big MaT dE hWuM MBgusi haKyuOBgCgGtBdC h Bds: fdhugushdEyGVhWs ayEds e hWVhWu aCladhaEu BOtByC ty Mahus OBg rWGs sBgrhBd n Hw hut Wm dBy BE us q45U:

S1hugday adC dhugday C O0s Bd gus shadtu ryaG a tgit ay gByu d CuhugM d dE hWu uO0thludus s BOaCsBgrhBd: zutaisu aCsBgrhBd s ad u1BhWugM t rgBtussV h s Eudugayy G aCl saKyu hB isu ad aCsBgKudh e hW WEW hWugMay t BdCi thl hG q2kU: fiWs - i ayhG Oat yhahus Wuah hgads Oug yuaC dE hB M d M , dE hWu gsT BOhWugMay CuEgaCah Bd: fd studag Bs e Wugu wo 5 t Bdtudhgah Bd d shguaMs s yBe VhWu Wuah hgads M ss Bd hB hWu sGshuM hWgBi EW aCsBgrhBd hudCs hB Ku syBe : fiGr tayy G rWGs tay dm hugath Bds agu dl Byl uCVsi t Was l ad Cug x aays OBgtus Bg e uaT t WuM tay KBdCs: x Wyu hWusu dhugath Bds MaG Kue uaTughWad hWu t WuM tay KBdCs Btti g dE d hWu aKsBgrhBd rgBtussV hWuG tad shyy Ku uO0thlu OBg tarhi g dE Easus q2V5U: vBg dshadtu VaCsBgKudhs Vsi t Was * uhaymgEad t vgaMue BgTs c* o vm2íí adC * o vm) jV] uByhu 2kQ adC 4HV athl ahuC tagKBd VadC tagKBd dadBhi Kus cwN fisjVWal u M t gBr BgBi s shgi thi gu e hW WEW si gOatu aguas adC hi dua Kyu r Bgu s , usVhWuguOBguVagu srut Ptayy G Cus EduC hB i hy, u Bd l ad Cug x aays OBgtus hB u O0thl uyG aCsBgK wo 5 ah yBe t Bdtudhgah Bds qkU: x Wyu hWusu dhugath Bds MaG Kue uaTughWad hWu t WuM tay KBdCs Btti g dE d hWu aKsBgrhBd rgBtussV hWuG tad shyy Ku uO0thlu OBg tarhi g dE Easus q4kV4) U: fd aCsBgrhBd V wo 5 MByuti yus aCWugu hB hWu si gOatu BOa sBy C Mahugay: fiW s VhWu tarat hG MaG Ku yM huC KG hWu al a yaKyu si gOatu agua Bd hWu aCsBgKudh . i Ksu- i udhyGV dt guas dE hWu tarat hG BOaCsBgrhBd nKasuC n Hw r yadhs MaG Ku ays B yM huC KG yadC i su: HCsBgrhBd ays B BOud Was l ag Bi s t Bdshga dhs hWah aO0th hs r gBCi thl hGV dt yi C dE yBe wo 5 suyuthl hG adC yBe ug guMBl ay uOPt udt Ge Wud t BMr aguC hB ayhugdahl u hut WdByBE us si t Was a KsBgrhBd rgBtussus: fiWu guMBl ay uOPt udt G BOwo 5 KG yBe nhuMr ugahi gu n Hw s Gs m huMs s t Bdhg Byyu C KG hWu uM ss Bds gusi yh dE OgBM Br ugah dE hWu sGshuM e Wt W s Ma dyG CBM dahuC KG hWu sBi gt u BOudugEGVOBi dC hB Ku gad E dE OgBM arrgB1 MahuyG 6 / hB arrgB1 MahuyG; 4 / q44U: fhis Mr Bgh adh hB dBhu hWah wy Mue BgTs r gBCi t us hWu WEW ush r i ghG wo 5 BOZ; ;:; / Kut ai su BOaCC dE si Ksu- i udh i d hs hB t BdCud su hWu e ahug t Bdhudh tarhi guC Ci g dE hWu r gBtuss:

wBdt ugd dE yBe nhuMr ugahi gu n Hw sGshuMs VhWu r g MagG t Bdhg Ki hBg hB hWu Blugayy udugEG gu- i guMudh s hWu Wuah t Bdsi MuC Ci g dE hWu CusBgrhBd r Wasu q48U: fiWu dut ussagG guEudugah Bd huMr ugahi gus hGr m tayyG gadEu OgBM 60 hB 250 °wVs Ed Ptadh yGyBe ug hWad hWBsu d hWu WEW m huMr ugahi gu n Hw r gBtussus VahagBi dC 600 °w OBg I o (guEudugah Bd q2kU: wBdsu- i udhyGVyBe adC MuC i M hWugMays Bi gt us y Tu EuBhWugMayV sByagVadC e ashushuaM Wuah t ad Ku uMr yBGuC OBg aCsBgKudhguEudugah Bd: Syuthg t hG s r guCBM dadhyG i hy, uC OBg wo 5 t BMr gus s BdV a g[Be hWgBi EW hWu r BgBi s shgi thi guVadC OBg Br ugah dE hWu l ati i M r i Mr hB uyM dahu r gBCi ths adC e ashu Ci g dE hWu Cuma g dE adC CusBgrhBd: Ludugayy GVhWu hWugMay udugEG gu- i guC Oayys e hWd hWu gadEu BO) –í :4 L DfIhBd wo 5 tarhi guCVe Wyu uyuthg t hG t Bdsi Mr h Bd WBlugs agBi dC 500 hBí 00 Tx WfIhBd wo 5 tarhi guC q48U:

fMr yuMudh dE Wuah gut Blug G sGshuMs hB tarhi gu adC gui su hWu Wuah Eudugah uC Ci g dE hWu aCsBgrhBd r gBtuss s BOMa9Bg Mr Bgh adt u as hWs tad s Ed Ptadh yG guCi t u hWu Blugayy udugEG t Bdsi Mr h Bd: fdhuEgah dE gudue aKyu udugEGs Bi gt us Vsi t Was s Byag Bg e dC r Be ug VhB si r r yG udugEG OBg hWu aCsBgrhBd r gBtuss s ays B Mr Bgh adh as hWs tad Wuyr guCi t u hWu guy adt u Bd dBdr gudue aKyu udugEG adC yBe ug hWu t agKBd OBBhr g dh q22U: fdl ush Eah dE aCl adt uC guEudugah Bd hut Wd - i us Vsi t Was M t gBe al u Bg gaC BOgu- i udt G WuahdEV hB at Wul u Oashug adC MBgu udugEGmOPt udh CusBgrhBd ays B Cusugl us ahhudh Bd:

. f2fi fi Olgcxmu dnvhmhm d H, hKis vKnr m

Htt BgC dE hB wagKBd SdE duug dEVI o (nKasuC n Hw tad tarhi gu BO wo 5 d hWu dyuha g) kU: (Be ul ugVaOugt Bds Cug dE hWu tagKBd uM huC KG hWu i su BOdahi gay Eas hB r gBl Cu hWu udugEG gu- i guMudhs BOhWu sGshuMVhWu tarhi g dE tarat hG hi ggdshB Kuyuss: x hW Cudht ayuuthg t hG si r r yG t BdC h Bds VyBe huMr ugahi gu n Hw cpfim Hwj u1WK huC a Eguahug tagKBd guMBl ay uOPt udt G t BMr aguC hB WEW huMr ugahi gu n Hw c(fim n Hwj VOayy dE e hWd hWu gadEu BO) 4 / hBí 0 / q48U: Ludugayy GVn Hw sGshuMs i hy, dE gBKi sh WGCgB1 Cu s BgKudhs CuMBdshgahu yBe ug uOPt udt us d t BMr ag s Bd hB aCsBgKudh nKasuC n Hw sGshuMs: fiWs C On Ougudt u s ahhg Ki huC hB hWu uyul ahuC huMr ugahi gu c600–; 00 °wj duuCuC d hWu OBgMug hB guyuasu wo 5:

n i g dE (fim n Hw r gBtuss Br ugah Bd VhWu s Byl udh's guEudugah Bd r gBm tuss Mr Bsus hWu WEW ush Ki gCud Bd hWu sGshuM's udugEG gu- i guMudhs: %s dE w S's hut Wd ByBEG as hWu hGr tayr gBtuss BOhWs hGr uVhWu tayt dah Bd BOwawo k t Bdsh hi hus hWu MBsh s Ed Ptadh r Bgh Bd BOhWu Wuah CuMadCV sr ut Ptayy G 4:54 L DfIhBd BOwo 5: HCC h Bdayy GVZ k80 Tx WfIhBd BOwo 5 s duuCuC OBg wo 5 t BMr guss Bd Va tgGBEud t a g sur agah Bd i d h OBg o 5 r gBCi th Bd VadC h Br Be ug hWu Oads adC ri Mr s q48U: HMBdE hWusuVwo 5 t BMr guss Bd s hWu MBsh udugEGmBdsi M dEVatt Bi dh dE OBgayMBshki / V OByyBe uC KG 55 / OBg hWu a gt Bdhat hBg adC 55 / OBg B1GEud r gBCi th Bd: L udugayy GVOBg hGr tay (fim n Hw s GshuMs VhWu Wuah CuMadC gad Eus QgBM 4 hB ; L DfIhBd BOwo 5 VadC uyuthg t hG CuMadCs gadEu QgBM k40 hBí í 0 Tx Wfl hBd BOwo 5 q48U:

fiWu WEW hhuMr ugahi gu gu- i guMudhs BOhWu (fim n Hw s GshuMs yM hhWu [u1 K yhG BOgudue aKyu udugEG i hy, ah Bd: Hd Cuay stu dag B OBg (fim n Hw e Bi yC Ku hB gi d Bd yBe nhagKBd OuysVy Tu K BMuhWadu Bg uyuthgByGht WGCgBEud QgBM gudue aKyu sBi gt us: fiWugu s r Bhudh ay OBg (fim n Hw hB hgads h Bd hB Oi yG uyuthg t Br ugah Bd d hWu Oh i guVKi hah hWu MBMudh hWs s BdyG Oa as Kyu Bd a sMayy stayu q) U: fiWu t BMMugt ayns tayu (fim n Hw sGshuM s Cus EduC hB i su dah i gay Eas as a sBi gt u BOWuah adC t ar hi gu wo 5 r gBCi t uC KG Eas t BMKi sh Bd Vuy M dah dE hWu duuC OBg aCC h Bday t ar m hi gu u- i r Mudh q) U: Hs a gusi yhV (fim n Hw's uM ss Bds agu s Ed Ptadh yG guCi t uC e Wyu t agKBd s shyy guMBl uC: Nul ughWuyuss V d hWu O hi guV O gudue aKyu udugEG s Bi gt us t ad Ku i su C hB r gBl Cu WEW hhuMr ugahi gu Wuah V tagKBd uM ss Bds t Bi yC Ku O ghWug guCi t uCV Ma1 M , dE gul udi u Br m r Bgh i d h us q) U: vash hgat T dE hWu t BMMugt ay al a yaK yhG BOyag Eus ntayu uyuthg t t ayt dah Bd hut Wd ByBEG s t Bds CuguC a hBr dut uss hG d BgCug hB Oat yhahu (fim n Hw r yadhs gi dd dE u1t yi s luyG Bd gudue aKyu udugEG:

fd hWu t asu BO (fim n Hw sGshuMs Va pwH shi C uC hWguu st udag Bs OBgMi yahuC KG ayhug dE KBhWhWu Wuah CuMadC adC hWu s Bi gt us BOuyut m hg t hG q4íU: v dC dEs gul uayuC hWah d hWu Kasuy du st udag BVa tagKBd guMBl ay uOPt udt G BO85 / t Bi yC Ku at Wul uC e Wud hWu uyuthg t hG Cum MadC e as OyPyyuC KG a dahi gay Eas t BMK duC t Gt yur Be ug r yadh fd hWu Kush adC e Bgshmnasu st udag BsVe Wugu s Byag r WBhBl Byha t cR$ j adC hWu al ugaEu t BayhPguC r Be ug r yadh d hWu %. H e ugu i su C as uyuthg t hG sBi gt us VhWu t agKBd guMBl ay uOPt udt us e ugu CuhugM duC hB Ku; k / adC 20 / Vgusr ut hl uyG q4íU:

. f2fi fi b vsiix myc r s o ge du l mhnhs r i t m r m yget hr, ysimhr hœili

fd hWs sut h BdV yBe nhuMr ugahi gu st ayuCmir n Hw sGshuMs agu t BMr aguC Pgsh x Wyu L yBKay fiWugMBshah sWBe s a yBe ug CuMadC hWad wy Mue BgTs d hugMs BOhBhay udugEG gu- i guMudhs VhWu H ghWuda hut Wm dByBEG Was dBh Kuud hush uC Guh OBg yagEu st ayu Bg Ku dE st ayuC i r as Br r BsuC hB L yBKay hWugMBshah adC wy Mue BgTs hut Wd ByBE us e Wt WVal u Kuud shi C uC u1huds l uyG ah yagEu r yBh yul uy: H ghWuda sGshuMs VBe ul ug gu- i gu a yBe ug huMr ugahi gu c60 °wj t BMr aguC hB hWu gush Vy Tuy G hB guCi t u ah st ayu hWu r gBtuss udugEG t Bdsi Mr h Bd VadC wy Mue BgTs gum - i gus hWu WEW ush huMr ugahi gu c200 °wj: z asuC Bd hWu r gBCi t uC wo 5 r i ghGV hWu H ghWuda sGshuM r gBl Cus r i ghG cí 0–60 / j yuss hWad hWu BhWug he B t BMr ad usVsB aCC h Bday hguah Mudh e yy Ku gu- i guC: fiWu WEW ush r i ghG c; ;:; / jVe Wt W s r gBl CuC KG wy Mue BgTs Vuy M dahus hWu dut uss hG OBg Oi ghWug hguah Mudh adC hW s aCC h Bday t Bsh s: wy Mum e BgTs Vays BVat Wul us a l ugG WEW t ar hi g dE uOPt udt G BO; 0 / Ve Wt W dBdu BOhWu hut Wd ByBE us t ad r gBl CuV att BgC dE hB gut udh yhugah i gu: z asuC Bd hWu r gul Bi s C st iss Bd adC al a yaKyu dOBgMah BdV h t ad Ku t Bdt yi CuC hWu hWu wy Mue BgTs sGshuM s hWu MBsh Mah i gu pfim Hw s GshuM OBg t BMMugt ay stayu: fiWu t Bsh Mr BsuC KG hWs hut Wd ByBEG t ad Ku a t Way yudEuVKi h wy Mue BgTs r guC t hs hWah KG 50k0 tagKBd guMBl ay t Bsh s e yyKu KuyBe %. J 540 fIhBd q46U:

wy Mue BgTs s hWu BdyG pfim Hw–KasuC t BMr adG e hWal a yaKyu C sm tyBsuC dOBgMah BdV s B MadG pwHs adC hut Wd Bmt BdBM t assuss Mudh s e ugu CBdu Bd hWu ghut Wd ByBEG hWs he yyKu OghWugt BMr aguC e hWwS's hut Wd ByBEG c(fim n Hwj : z asuC Bd hBhay udugEG CuMadCVwS's sGshuM gum - i gus a WEWug CuMadC hWad wy Mue BgTs VadC hWs s 9 sh PuC KG hWu l ugG

1fl fi h nn nmhgfi

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WEWguEudugahBd huMrugahi gu c600–; 00 °wj gu- i guC hB guEudugahu hWu I o(sByi h Bd adC hWu duuC OBg BhWug O ghWug hguahMudh i d hs d hWu wS sGshuM u:E: syat Tug: fiWu ti ggudht BshBOwS's hut WdByBEG s dBhC st yBsuCV dul ughWuyuss VhWu g u1r ut huC t Bsh hB Ku guat WuC KG 5054 s ;)–5k5 %. J flhBd wo 5 tar hi guC: buhVhWu r i gh G r gBl CuC KG wS c; í :2 / j s sh yy yBe ug hWad wy Mue BgTs WBe ul ug h s sh yy WEWadC CBus dBhduuC O gh hWug hguahMudh: Htt BgC dE hB hWu yadC i suVhWu Yo F wH' r yadh KG wy Mue BgTs V e hWa tar at hG BO) V000 Muhg t hBds r ug GuagVWas a s , u BOí ; 6:; M5 q8U: fiWu Y fiF Hfio . ' r yadh KG wS Ve hWa tar at hG BO2 M yy Bd hBds flGuagVWas ad ush MahuC agua BO 500 V000 M5 q8U: fd Eudugay V hWu dC gut h yadC Bt ti r ah Bd guyahuC hB hWu si r r yG t Wa d OBg (fim Hw sGshuMs sa KBi h OBi g h Mus Eguahug hWad hWah BOhWu pfim Hw sGshuMs Vsr ut Pt ayG hWu huMr ugm ahi gu se dEnKasuC Bdus: fiWs C O0ugudt u s r g Mag yG ahg Ki huC hB hWu Madi Oat hi g dE ad C ud CnBOgy Ou shaEus BOn Hw i d hs adC aCs BgKudhs qk8U: z G yul uys dE hWu addi ay r yadhs' tar at hus r ug agua V h s dBh tuC hWah KBhWr yadhs agu tar aKyu BOtar hi g dE addi ayyG 4 hBds BOwo 5 flM5: wagKBd tar hi gu adC gu Eudugah Bd i d hs agu sur agahu d (fim Hw sGshuMs Ve Wt W uda Kyu t Bdh di Bi s tagKBd aKs Bgr h Bd adC gu Eudugah Bd: fd t Bdhgash Vp fim n Hw hut WdByBEG t BMK dus aCs Bgr h Bd adC Cus Bgr h Bd d Bdu i d h fiWs y M hs uat Wshur 's Br ugah dE h Mu: fiWugu MaG Ku ad dt guasu d hWu t Bsh BO h Mu Mada EuMudh adC sh Bg dE BOgudue aKyu udugEG WuahVas a gusi yh BO hWs q24U: H hut WdBmut BdBM t assuss Mudhi suC wS as a Kasu tasu OBg (fim n Hw e hWad uyut hg P uC sGshuM adC wy Mue BgTs' hut WdByBEG as a Kasu tasu OBg pfim Hw q24U: S yut hg P uC sGshuMs OBg n Hw i su uyut hg t hG hB r Be ug hWu t ar hi gu r gBt uss: fiWu yul yusuC t Bsh s BO(fi adC pfi d 5050 agu 6 í 6 %. J flhBd wo 5 tar hi guC adC í 66 %. J flhBd wo 5 tar hi guC Vgus r ut h luyG q24U: fiWu uyut hg t hG CuMadC BO(fim Hw adC pfim Hw agu 2V4k4 adC 540 Tx WflhBd wo 5 tar hi guC Vgus r ut h luyG: pfi gu- i gus ad aCC h Bday yBe m huMr ugahi gu Wuah CuMadC BO 2V40 Tx WflhBd wo 5 q24U: fiWu t Bsh s BO (fifl pfi agu u1r ut huC hB Cut guasu KG 5040 as OBy yBe s350k0 ckí 6 flkk6 %. J flhBd wo 5 jV50) 0 c584 fl5kí %. J flhBd wo 5 jV adC 5040 c555 fl2; ; %. J flhBd wo 5 j q24U:

vgBM a tagKBd OBBhr g dh l ue r B dhVOBg hWu tar hi gu adC sh BgaEu BO2 hBd BOwo 5 l a (fim Hw adC pfim HwV0:46 adC 0:k0 hBds BOwo 5 e yy Ku uM hhuC dhB hWu ahMBsr WuguV gus r ut h luyG qk8U: fiWu r g MagG Oat hBg d[i udt dE y Oum Gt yu Eguud WBi su Eas uM ss Bds d hWu r gBt uss s hWu duuC OBg r gBt uss Wuah hB u1hgath wo 5 QgBM hWu sBgKudh qk8U: fiWu tagKBd OBBhr g dh OBg n Hw sGshuMs tad Ku M d M , uC KG hWu i su BOyBe rnagKBd udugEG sBi gt us Bg Kuhug udugEG dhuEgah Bd t BdP Ei gah Bds V as C sm tissuC d hWu r gul Bi s suth Bd OBg uat W tasu: . dt u (fim Hw sGshuMs gu- i gu hWu WEWush udugEG OBg guEudugah Bd hWuG MrBsu hWu WEWush tagKBd OBBhr g dh

x ahug CuMadC d hWu n Hw sGshuM tad ays B r yaG a gByu d hWu si sm ha daK yhG BOhWu guyahuC hut WdByBE us: fiWu aMBi dh BOe ahug ular BgahuCV Ci g dE hWu n Hw r gBt uss ah WEWhuMr ugahi gu e hWa- i uBi s sByi h Bds V MaG lagG QgBM 0 hB 40 hBdsflhBd wo 5 tar hi guC q24U: fiWs ular Bgah Bd s t Bdh dEud hhB Oat hBgs sit Was hWu huMr ugahi gu adC Wf M C hG BOhWu si gm gBi dC dE a gV as e uyy as hWu say h t Bdt udhgah Bd BO hWu sByi h Bd: fiWu guEudugah Bd r gBt uss d (fim Hw dl Byl us sul ugay r gBt uss us hWah MrBsu uyul ahuC huMr ugahi gus Ve Wt W tad yuaC hB e ahug ular Bgah Bd adC yBss@ I uur dE at Bds hadh aMBi dh BOe ahug d hWu ay Tay s Byi h Bd s MrBgh adh hB t Bdh gBy h Wu aKs BgKh Bd T dh ts: vBg dsh adt uV wagKBd SdE duug dE's due Cus Ed gu- i gus):í hBds BOe ahug flhBd wo 5 tar hi guC ah aMK udh t BdC m h Bds BO8) / F(adC 50 °w q24U: wy Mue BgTs tad WBe ul ugt ar hi gu 0:6–5 hBd BOe ahug flhBd BOwo 5 tar hi guC q24U: pfi n Hw sGshuMs MaG hWu guOBgu Kut BMu a duh duagnGu Bd suC e ahug r gBCi t ug hB si sh a d BhWug r gBt ussus V gur gus udh dE ad aCC uC l ayi u hB hWu r gBt uss:

wo 5 yBe t Bdt udhgah Bds d hWu a g s hWu MBsht Wayyud E dE BKsh at yu hB n Hw ut BdBM t Oas K yhG: fiWs s e WGl ugG WEWyG suyut h l u Mah ug ays agu gu- i guC hB Ku ar r yuC d n Hw ar r yt ah Bds: Nul ughWuyuss VhWu t Bdh aM m dadhs d a g adC t BMr Bs h Bds tad l agG QgBM CaG hB CaG adC QgBM yBt am h Bd hB yBt ah Bd: fiWu yBe t Bdt udhgah Bd BO wo 5 d hWu a g ayyBe s BhWug Easus r gus udh hB t BMr uhu e hWwo 5 Bd at h l u s hus BOhWu t ar hi g dE s Bgm Kudh fiWu MBsh Mr Bgh adh t Bdh aM dadh hWah t Bi yC a Oat h hWu t ar hi g dE r gBt uss s Wf M C hG: fiWu e ahug l ar Bg t Bdh udh t ad Cut guasu hWu t ar hi g dE t ar at hG BOwo 5 OBg MBsh n Hw sGshuMs KasuC Bd r WGs s Bgr h Bd Mahug ays V

si t Was * o vs ad C] uByhus VCi u hB t BMr uh h l u aCs Bgr h Bd: (Be ul ug VhWs t ad Ku uas yG s Byl uC KG dhgBCi t dE a t Bd Cud sug KuOBgu hWu t ar hi g dE t WaM Kug hB CuWf M C OGhWu dyuha gVas CBdu d wy Mue BgTs hut WdByBEG:

HOhug u1hgat h dE wo 5 QgBM hWu ah MBsr WuguVhWugu agu Mi yh r yu Br h Bds OBg hs i h y, ah Bd: fh t ad u hWug Ku sh BguC i d CugEgBi d C OBg yBd Erhug M guMBl ay Bg u Mr yBGuC C gut hyG OBg l ag Bi s r i gr Bsus Vsi t Was Kul ug aEu t agKBd ah Bd VOugh y, ah Bd d Eguud WBi sus VBg as a gu Q; Eugadh: HCC h Bdm ayyGVwo 5 t ad Ku i su C dC gut hyG as a OuuCsh Bt T OBgr g Btussus hWah Eudugah u t WuM tays VOi uys V adC Ki yC dE Mah ug ays: HMBdE hWu 26 n Hw r yadhs ti ggudhyG Br ugah Bday EyBKayyGVBdyG he B agus hBg dE wo 5 d a sr ut Pt ayyG Cus Edah uC sh Bga Eu s huVe Wt W ag u og t a adC Hgt ht OB1 wy Mux BgTs' r yadhs q) U: fiWu guMa d dE 28 r yadhs agu t ar hi g dE wo 5 OBg MMuC ah u i su d duagKG dCi sh g ayQat yh us: wo 5 Was sul ug ays h Bga Eu Br h Bds V dt yi C dE EuByBE tay sh Bga Eu d Cuur say du a- i OugsVCur yuhuC B y adC Eas PuyCs V adC Bh Wug gBt T OBgMah Bds: fiWu u1r ud sus adC h Mu gu- i guC hB ush a Kys W wo 5 sh Bga Eu Qat yh us l agG Kas uC Bd hWu yBt ah Bd adC agu d[i udt uC KG Qat hBgs sit Was hWu al a ya K yhG BOsi Ksi gQat u Cah a adC gus ugl B g r gBr m ugh us: fiWu t Bsh s assBt ahuC e hWwo 5 sh Bga Eu t ad Ku guyah l uyG yBe : vBg dsh adt uV MBgu hWad WayOBOBds WBgu sh Bga Eu d hWu %d huC . hahus s r gBm 9uth uC hB Ku attuss Kyu aha t Bsh Kuy Be %. J 20 flhBd BOwo 5 Vad C arr gB1m Mah uyG WayOBO hs BOBWBgu sh Bga Eu s r gB9uth uC hB Ku al a ya Kyu aht Bsh s Kuy Be %. J k4 flhBd BOwo 5 q) U:

. f2fDfi Mu nvglr g mycr s osglni s v a I b

fiWugu agu sul ugay uMug E dE n Hw s Byi h Bds hWah Wal u Kuud u hWug r gBr Bsu C hWu Bguh t ayyG Bg uysu CuMBdsh ga huC ah yBe hut WdBy BEG gua C duss yul uys c2–kj: fiWusu shga huE us dt yi Cu c j MuMKgadu sur agah Bd Vas e uyyas c j a WGKg C r gBt uss dl Byl dE aKs Bgr h Bd adC uyut hgBC ay Gs s adC e yy Ku r gus udhuC d hWs sut h Bd:

* uMKgadus agu aMBd Esh hWu MBshuOPt udh MuhWBCs BOt ar hi g dE wo 5 QgBM [iu Eas nhGr u uQ] iudhs s dt u hWuG agu guyah l uyG du1r uds l uV s Mr yug hB ds hayy adC Br ugah uVad C yual u a s Mayyug ut ByBE tay OBBhr g dh hWad s Bgr h Bd r gBt uss us: fiB Ma1 M , u MuMKgadu r ug Muadt u OBg wo 5 t ar hi gu QgBM a gV WBe ul ug VhWu Mah ug ays suyut huC s WBi yC Ku P dumhi duC e hWu1hguMuyG wo 5 nWyt t BMr Bi dCs Ve Wyu hWu hWt Tduss BOhWu sum yut h l u ya Gug BOhWu MuMKgadu s WBi yC Ku guCi t uC hB a dadBst ayu yul uyhB si r r Bgh Oash gads Oug adC u1hguMu suyut h l hG: (Be ul ug VhB CahuV wo 5 sur agah Bd e hWMuMKgadus s dBh Guht BMMug t ayyGal a ya Kyu Bd a yagEu stayu adC sh yy duuCs aCC h Bday Mr gBl uMudhs hB Ku i suC ah l ug GyBe sByi h t Bdt udhgah Bds BOwo 5 d a g adC hB Ku ut Bd BM t ayyG Oas Kyu: wo 5 Eas sur agah Bd QgBM BhWug Eas us s Ma dyG at t BMr y s WuC i s dE Eyass G Bg gi KKug G r ByGMug t MuMKgadus: fiWu Ma d BK9uth l u s hB Bl ug t BMu adC sByl u hWu hga Cun BOO Kuhe uud u1 sh dE r ByGMug r ug Mua K yhG adC suyut m h l hG q4; U: Hs hWu Ma d ar r yt ah Bd BOMuMKgadu Eas sur agah Bd VMBsh r ByGMugs Wal u Kuud u1a M duC OBg guMBl dE wo 5 QgBM Muh Wadu q80U: Hs a sh ag h dE d hah l u OBg i s dE MuMKgadus d n Hw Vs BMu shi C us dl ush m Eah uC si t Wr ByGMug MuMKgadus d wo 5 flN5 M 1hi gus: fiWu r ugOBg Madt u BO Eyass G r ByGMugs d sur agah dE wo 5 V Cur ud C dE Bd hWu g r WGs t Bm t WuM tay r gBr ugh us Ve as r gBM s dE: L yass G r ByGMugs shi C uCV si t Was RByGc2 mhg MuhWGys yGyr2 mgBr Gduj cRfi* . RjV RByGMugs BO dhg ds t M t gBr BgBs hG cRf* sjVRByGcuhWugmi yOBduj cRS. j agu WEWjGgur gBCi t Kyu ad C Wal u at t ur haKyu Mut Wad tay r gBr ugh us: (Be ul ug VhWu g r ug OBgm Madt u e as s Ed Pt adh yG gu Ci t uC as a gus i yh BOr WGs tay Bg t WuM t ay ah m hat Ts q80U: o d hWu BhWug WadCVgi KKug G r ByGMugs t Bi yC Ku t Bds Cug uC a Kuh hug t WB t u OBg wo 5 t ar hi g dE d n Hw Vs dt u gi KKug G r ByGMugs Vsi t Was RByGC MuhWGys yB1adu cRn* . j & RSz HQVagu dBh si st ur h Kyu hB r WGs tay aE dE as Eyass G Bdus: fiaKyu k t BMr agus Eas sur agah Bd BO wo 5 d wo 5 flN5 Eas M 1hi gu hWgBi EWMuMKgadus MaCu BOEyass G adC gi KKug G r ByGMugs V adC due r BgBi s tagKBd mu By hu M 1uCmMah g 1 MuMKgadu: vBg n Hw ar r yt ah Bd V suyut h l hG: yuss hWad) 0–40 t add Bh Ku at t ur haKyu du hWug uOPt udh Kut ai su BOhWu yBe t Bdt udhgah Bd BOt agKBd C B1 Cu d hWu ah m MBsr Wugu: RSz HQVas suud d fiaKyu 5V s si EEus huC as a r gBM s dE ad C stayaKyu Mah ug ayOBg MuMKgadu Cus Ed OBg n Hw: H s Mi yah uC Mi yh sha Eu MuMKgadu r gBt uss Vi s dE H. RSN Rp%. Ve as i suC hB ul ayi ah u hWu r Bm hudh ay BO i s dE MuMKgadus OBg n Hw Vs r ut Pt ayyG ad i yhgamhWd Qguum sha dC dE s yB1adu dadBMuMKgadu ad C hWu udugEG gu- i guMudhs q82U:

1 fi fi h nn nmhofi

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auf c2 .

wBMrag sBd BOwo$_5$ suragahBd rugOBgMadtu d CgGs MiyahuC a g KG C Oogudh MuMKgadus:

RByGMugfl MuMKgadu Mahug ay	nuha ys	wBdC hBds cfifl Rj	wo$_5$ rugMuadtufl rugMuaK yhG	. uyuthl hG cwo$_5$fl N$_5$j	FuO
RSzHQ * (284í c80 / RSoVj0 / RH8j	fiWugMBryasht rByGuhWugnKyBtTmaM Cus %suC d hiWd PyM tBMrBs hBd MuMKgadu cfiw* j	54 °w 5 Kag	256 ± 2í zaggug	8)	q250U
Rn * . crByGC MuhWGys yB1aduj	Fi KKugGrByGMug %suC d cfiw* j	54 °w 5 Kag	kVk; 4 ±44 zaggug	22	q250U
Rfi* . R	LyassGrByGMug	54 °w	5; V000 zaggug	20:í	q80U
Rf* nª	LyassGrByGMug	k0 °w 0:5 Kag	5Vk00 zaggug	54	q252U
. Hzo −k) ck0 / e hyBaC dEj	RBgBis tagKBdmuByhu M 1uCmMahg 1 MuMKgadu	k4 °w 2 Kag	5V824 zaggug	k2	q255U

fiWu Bi hyuht Bdtudhgah Bd BOhWu guhudhahu Eas e as Cus guC hB Ku u- i ayhB k00 r r M: fiB MBCuyhWu suragah BdV) MuMKgadu shaEus e ugut Bds CuguC: fh e as t Bdt yi CuC hWah h s r Bss Kyu hB at Wul u hWu hagEuh wo$_5$ t Bdtudm hgah Bd e hW MuMKgadu suragah Bd hWah Was a wo$_5$ suyuthl hG as yBe as k0: (Be ul ugV BhWug Eas us aysB rugMuahu Oashug d sGshuMs e hW yBe suyuthl hGV yuaC dE hB a gar C dtguasu d wo$_5$ t Bdtudhgah Bds d hWu guhudhahu shguaMs: fiWugu OBguV hWu yBe ug suyuthl hG MuMKgadu sWBi yC Wal u a sMayyug agua hWad a WEW suyuthl hG Bdu: Hs a gusi yhV hWu MuMm Kgadu sWBi yC dBh guyuasu guhudhahu Eas e hWMBgu hWad k00 r r M BOwo$_5$: x hWWEWjG wo$_5$ suyuthl u MuMKgadus Vwo$_5$ uM ss Bds adC ri Mr s udugEG t Bdsi Mr h Bd agu guyah luyG yBe : fiWu WEWug hWu suyuthl hGV hWu WEWug hWu wo$_5$ t Bdtudhgah Bd d hWu rgBCi th Eas V hWu yagEug MuMKgadu agua duuCuC VadC hWu yBe ugh Wu udugEG gu- i guC:

H t BMK dah Bd BOaKs Bgr h Bd adC uyuthgBC ayGs s rgBtuss e as Pgsh rgBr BsuC Z he B Cut aCus aEB d L ugMadG: fiWu MuhWBC Cul suC dl Byl u hWu dhaTu BOa gVe Wugu d hWu wo$_5$ rgusudh d hWu a g s aKs BgKuC i s dE a Nao (sByi h Bd q85U: fiWu wo$_5$ s hWud guyuasuC d a duagyG ri gu OBgM KG at C OG dE hWu rgBCi th Na$_5$ wo$_k$ e hW($_{5.}$ o$_)$: . i Ksu- i udhshurs dl Byl u hWu gushBgah Bd BO Nao (adC si yO) g t at C hWgBi EW ad uyuthgBt WuM tayyG Cg l ud MuMKgadu rgBtuss cuyuthgBC ayGs sj: NBhaKyGVhWu rgBtuss u1tyi m s l uyG guy us Bd uyuthg t hGVe hWBi hhWu duuC OBghWugMayudugEG: fd 500; V hWu rgBtuss i dCuge udha guCus Ed OBgt Bdh di Bi s Brugah Bd Vuy M dah dE hWu i hy, ah Bd BO($_{5.}$ o$_)$ q85U: fiWu ussudhayat C Ptah Bd BOhWu Na$_5$ wo$_k$ sByi h Bd e as tagguC Bi hC gut hyG d ad uyuthgBC ayGs s tuy: n usr hu hWusu aCl adtu Mudhs VhWugu Was Kuud dB t BMMugt ayar r y tah Bd BOhWu rgBtuss:

Ht Wul dE uOPt udh suragah Bd e hW MuMKgadus OBg n Hw gu- i gus aCCguss dE sul ugay Oa th Bgs Ci u hB hWu yBe t Bdtudhgah Bd BOwo$_5$ d hWu OuuC@WBe ul ugVuyul ahuC r gussi gu s dBh dut ussagG OBg hWs rgBtuss: fiWu yBe ug hWu t Bdtudhgah Bd VhWu WEWug hWu suyuthl hG duuCuC: fiB Ma1 M , u MuMKgadu rugMuadtu OBg wo$_5$ tar hi gu QgBM a gVhWu Mahug ays sWBi yC Ku Pdurhi duC e hW WEWjG wo$_5$ −r Wyt t BMr Bi dCs: HCC h Bday GVhWu sum yuthl u ya Gug BOhWu MuMKgadu sWBi yC Ku gu Ci t uC hB dadBst ayu hWt Tdu ss hB si r r Bgh Oash hgads Oug adC u1hguMu suyuthl hG . i gOa t u O) d th Bday, am h Bd BOMuMKgadu is dE Mahug ays si t Was RByGuhWGyudu M duVEgar Wudu B1 Cu cL o j VadC , uByhus tad ud Wadt u wo$_5$ suyuthl hG c>) 0j: * BguBl ugV C gut h dE a g BdhB hWu MuMKgadus i s dE a t BMr gussBg t ad Wuyr at Wul u hWu dut ussagG sur agah Bd uOPt udtG: vBg dsh adt u Va shi CG s Mi yahuC a Mi yh sha Eu MuMKgadu rgBtuss i s dE H. RS N Rp% hB ul ayi ahu hWu r Bm hudh ay BOBgEad t m ByGMug MuMKgadus OBg n Hw Vsr ut Pt ayyG i yhgam hWd Oguush adC dE s yB1adu dadBMuMKgadus ck) dM hWt Tj VadC hWu g udugEG gu- i guMudhs q) U: fiWu dyuh r gussi gu e as suh hB ahMBsr Wug t r gussi guV adC hWu rugMuahu r gussi gu e as suh ah 4 TRa: z G i s dE OBi g shaEus BO MuMKgadu sur agah Bd d sug us e hW a wo$_5$ suyuthl hG BO 40 V h e as r Bss Kyu hB at Wul u i r hB a 88 / wo$_5$ t Bdtudhgah Bd d hWu rgBCi th Eas i dCug a MK udh r gussi gu t BdC h Bds: fiWs l ay Cahus hWah WEW r gussi gu s dBh gu- i guC hB at Wul u uOPt udh suragah Bd i s dE MuMKgadu rn Hw:

. f2fpfi a I b iyhovHHt ds mr rthat hr, ychomrgni

fiWu Eguud WBi su Eas cL (L j uM ss Bds BO n Hw t BdPEi gah Bds agu s Ed Ptadhy G d[iudtuC KG hWu sBi gt u BOudugEG si r r yuC OBg Wuah adC uyuthg t hG Ci gdE hWu wo$_5$ tar hi gu r gBtuss: x ashu Wuah s ragh ti yagyG udl gBd Mudhayy G aCl adhaEuBi s as a Wuah sBi gt u: fiWu L (L dhuds hG BO hWu uyuthg t hG M 1 Bd hWu Eg C s a t g h t ayGa th Bg OBg n Hw t Bd PEi gah Bds t Bdduthu C hB hWu Eg CVad C hs Mr at hl ag us KG t Bi dhgG: wBi dhg us hWah t BMK du hWu i su BOe ashu Wuah e hW M 1us BOyBe L (L mdhuds l u uyut m hg t hG CuMBdshgah u hWu yBe ush L (L uM ss Bds: vBg dsh adt u VNBge a G ad C ftuy ad C at Wul uC L (L guMBl ayuOPt udt us BO; í / ad C ;) / Vgus r ut m h l uyGVBKha duC KG ad pwH shi CG i s dE hWu wy Mue BgTs n Hw s GshuM as a Kasu t asu q44U pfd t Bdhgash Vt Bi dhg us Wual yG guy adh Bd OBss y O) uys OBg uyuthg t hGVy Tu L guut u Vu1r ug udt u WEWL (L uM ss Bds VayMBsh guat Wd E duhm Bs h l u L (L uM ss Bds ah 0:; 2mBd wo$_5$ flBd wo$_5$ t ar hi guC OBg Eg Cm t Bi r yuC n Hws q44U: Hi hBd BMBi s sGshuM Cus Eds uMugEu as a r gBM s dE ayhugdah l uVs WBe dE L (L guMBl ayuOPt udt us gadE dE QgBM í ; / hB ; 2 / q44U Vr agh ti yagyG d yBtah Bds e hW a Mr yu sByag ggaC ah Bd Vuy M m dah dE hWu duuC OBg OBss y O) uymKasuC Eg C uyuthg t hG adC Wuah t Bdsi Mr m h Bd: fiWu PdC dEs si EEush hWah KG uMr yBG dE EuBhWugMay udugEG as a Wuah sBi gt u ayBdE e hWa r guCBM dadhyG gudue aKyu uyuthg t hG M 1 VhWu uOPt udt G BOtagKBd guMBl ayt ad guat W; k / q48U: %dCug Br h May t Bdm C h Bds i hy, dE e ashu Wuah adC yBe magKBd uyuthg t hGV hWu tagKBd guMBl ayuOPt udt Gt ad ayMBsh guat W; í / : (Be ul ugVhWs PEi gu t ad CgBr s Ed Ptadhy G hB as yBe as 6 / e Wud hWu Eg C uyuthg t hG s r guCBM dadhyG sBi gt uC QgBM OBss yr Be ug q48U:

fiWu t Bsh BO adC r Bhudhay BO n Hw OBg t Bi dhg us adC t BMr ad us hB Mr yuMudh guMa d t gi t ay dhugg BEah Bds: z G 5040 Vn Hw s WBi yC Ku a Kyu hB guMBl u E EahBdmst ayu wo$_5$ OBg %. J 200 flhBd Bg yuss q8U: fh MaG Ku ut BdBM tayyG l aKyu hB rugOBgM n Hw s hWu r g t u OBgh Wu t ar hi gu BOa h Bd ar r gBat Wus %. J 200: Hs BOdBe Vn Hw guMBl ay t Bsh s agu Kuhe uud %. J 500 hB 800 flhBd Ve Wt W s Qag QgBM hWu EBay: Nul ugh Wuyuss Vn Hw t Bsh e yy OBg si gu l agG QgBM guE Bd hB guE Bd: nuMBdshgah Bds BOn Hw hut WdByBEG Wal u ayguaCG ha Tud r yat u d Si gBr u adC NBgh WHMug ta: fiWu su guE Bds agu CuuMuC si haKyu OBg WBsh dE aCC h Bday n Hw Qat yh us Ci u hB hWu g att i Mi yahuC u1r ug udt u adC hWu r Bhudh ay OBg t BngBt ah dE e hWu1 sh dE dCi sh gay t udhgus Vas e uyy as ush aKys WuC dQgashgi t hi gu OBg hgadsr Bgh dE adC sh Bg dE wo$_5$: o hWug guE Bds hWah u1WK h t Bsh t BMr uh hl uduss OBg CuryBG dE n Hw dt yi Cu hWBsu e hWu1 tur h Bday GWEWgudue aKyu udugEG r Bhudh ayVsi t Was NBgh WHQg ta adC hWu * CCyu Sash HCC h Bday GVgum E Bds e hWyBe dah i gay Eas r g tus Vsi t Was hWu * CCyu Sash adC Fi ss aV adC hWBsu e hWa shgBdE dhugush d wo$_5$ i hy, ah Bd Vsi t Was Dar ad Vagu t Bds CuguC l aKyu OBg n Hw Cur yBGMudh: Hha guE Bday yul uyV h s adh t m r ahuC hWah yBe ug wHRSQ OBg n Hw e yyKu d NBgh WHQg ta VwWda VF i ss aV adC hWu * CCyu Sash VhWad d Si gBr u adC %. Ci u hB t Bsh m Oat h l u Mam hug ays adC Madi Oat hi g dE q) U: FuE Bds aKi dCadh d Eas gusBi gt us Vsi t W as hWu Fi ss a adC hWu * CCyu Sash Vagu u1r ut huC hB Wal u yBe ug Eas r g tus t BMr ag uC hB Si gBr u adC hWu %d huC . hahus: . Mi yha du Bi syGVwo$_5$ r g tus agu r gB9ut huC hB Ku WEWug d Si gBr u VhWu %d huC . hahus V adC Dar ad c≤%. n %. J 540 flhBd wo$_5$ j hWad d hWu aOBgu Mudh BduC guE Bds q) U: fiWu su Oat hBgs t Byyut h l uyG t Bdhg Ki hu hB a guE Bday Cut y du d hWu t Bsh BOt agKBd tar hi guC l a n Hw KG k2–) k / QgBM 5050 hB 50k0 adC KG 20–5) / QgBM 50k0 hB 5040 q) U:

vBg n Hw hB Ku i su C hB t BMK ah t y Mah ut WadEu KG tar hi g dE wo$_5$ VhWu stay dE i r BO hWu r gBtuss sWBi yC Ku u1huds l uyG shi C uC adC O) gh Wug Cul uyBr uC: z uyBe agu sBMu t Bds Cugah Bds adC ar r gBat Wus dl Byl uC d stay dE i r n Hw q8V55U: fiWu Pgsh Bdu s hut WdByBE tay aCl adtu Mudh . tay dE i r n Hw gu- i gus hWu Cul uyBr Mudh adC Cur yBGMudh BO MBgu

uOPt udhadC t Bshmn Oatthl u hut WdByBE us: HguCi th Bd d Br ugah Bdayt Bshs tad Ku at Wul uC KGaCl adt dE adC Br h M , dE wo 5 sBgKudhsVBr h M , dE a g t BdhatHBgsVadC guEudugah Bd i d hs: fiWu gut udh OBt i s Was Kuud Bd MBCi yag i d hs adC r ass l u a g t Bdhat HBgs q8U: Hs OBg n Hw u- i r Mud hV Mr gBl u Mud hs d hs Madi Oat hi g dE adC flBg t guah Bd t ad yBe ug hWut Bshs: Hs OBg hWu s BgKud hs VaObug MadG t Gt yus BOyBaC dE adC i dy BaC dEVhWuG Cuhug Bgah u: o l ug h MuVhWs r gBt uss guCi t us hWu s BgKud his - i ayhGVe Wt W i yh Mah uyG t BMr gBM sus tagKBd t ar hi gu's uOPt udt G adC t ar at hG: (udt uV h s Mr ugah l u hB Cul uyBr WEWugmhar at hG s BgKud hs i hy, dE gua C yG al a ya Kyu Mah ugays i t Was K Bt Wag adC s yt a q24U: HCC h Bdayy GV hWugu s a duuC hB C st Blug MBgu udugEGmOPt udh Muh ayB1 Cu aCs BgKud hs q24U: HCCguss dE udugEG CuMadCs s adBhWug t gh t ay asr ut hV as hWu hut WdByBEG s ti ggudhyG WdCugu C KG WEWudugEG gu- i guMud hs: fMr yum Mud hdE MB shi gu se dE hut Wd - i us t ad r Bhudh ayyG guCi t u hWu udugEG gu- i guC OBg guEudugah BdVe Wyu uyut hgBmse dE r gBt uss us MaG uyM dahu hWu duuC OBg hWugMay udugEG ayhBEuhWug q8U: vi ghWugMBguVi hy, dE yBe m t BshVgudue aKyu r Be ug s Bi gt us Vsi t Was gut Gt ydE e ashu WuahVhB Br ugah u n Hw r yadhs Was hWu r Bhudh ayhB O ghWug guCi t u Br ugah Bdayt Bshs: HdBhWug arrgBat WhB t Bsh guCi th Bd dl Byl us hWu Mass r gBCi th Bd BOn Hw i d hs V r g Bg h, dE ad dt guasu d hWu - i adh hG BOi d hs gah Wug hWad hWu g dC m l Ci ays , u q8U: z G arryG dE hWu r g dt r yus BOyuagd dE KG CB dE d hWu Mass r gBCi th Bd BOn HwV h s adh t rahuC hWah t Bshs e yy Cut guasu s Ed Pt adhyG adC se OhyG: HdBhWug Mr Bgh adh asr ut hs hB t Bds Cug s hWu aKsud t u BOEBl ugd Mud hay Kat T dE adC r Byt G si r r Bgh hWah r Bsu a t Wayn yud Eu hB hWu e Cusr gua C aCBr h Bd BOn Hw Bd a yagEu st ayu q2) U: RByh t ay ud CBgsuMud h s i d Cud aKyG a t gi t ay uyuMud h d uda Kyd E n Hw hut WdBym BEGVr agh t i yagyG d Cg l dE CBe d hs t Bsh hB Kuy Be % J 200 r ug hBd: fd hay dl ush Mud hs adC hWu ush aKys WMud h BOsi r r Bgh l u r Byt G Qga Mum e BgTs agu ussudh ay OBg hWu si t t uss Oi y Mr yuMud hah Bd BOMass r gBCi t m h Bd adC Cur yBG Mud h BOa CC h Bday n Hw Oat yh us: fiWu yash agua hB t Bds Cug s dhuEgah Bd e hWt agKBd Mada EuMud h . t ay dE i r n Hws WBi yC Ku at t BMr ad uC KG gBKi sht agKBd Mada EuMud hs hga huE us: fiWs dl Byl us Cul uyBr dE dQashgi h gu OBg wo 5 sh Bga Eu Bg Cud hOG dE l aKyu i hy, am h Bd Br h Bds si t Was tagKBd–dui hgay Oi uys Bg Ma hu gays r gBCi th Bd:

o hWug gBi hus hB M h Eah u wo 5 d udl gBd Mud hay ut Bs Gs huMs sWBi yC ays B Ku u- i ayyG dl ush Eah uC adC Bdu BOsi t WguyG dE Bd shg r r dE wo 5 QgBM hWu Bt uads VguOugguC hB as n gut h o t uad war hi gu cn o wj Ve yy Ku r gus ud huC d hWu du1h su t h Bd:

fip I 1i2 l g 2ut uelsi2 gy y 2i 1uce1kgl dvdl2y d

o t uads agu ussudh ay hB hWu EyBKay tagKBd t Gt yu Ci u hB hWu g l ash tagKBd sh Bga Eu t ar at hGVBOa r r gB1 Mah dE k6V000 E Eah Bds q8kUVe Wt W s s Ed Pt adhyG Eguah ug h Wid u h Wug hWu í 00 E Eah Bds t ar at hG BOhWu ah m MBsr Wugu Bg hWu 5V000 E Eah Bds t ar at hG BOhWu hugg ush gay K Bsr Wugu q8) U: HCC h Bdayy GVBt uads aKs BgKZ 5 E Eah Bds BOwo 5 addi ayyGVBl ug he B BgCugs BOMa Ed hi Cu Eguah ug hWid hWu a MBi dh d hWu ah MBsr Wugu q84V88U: H due sh ah sht Cur t hu C hWah Bt uad addi ay wo 5 s dT Ci g dE 5025–5052 e as 58 / BOhBhay wo 5 uM ss Bds q8í U: o t uad at C Pt ah Bd s ays B a Ma9Bg t Bdt ugd OBg Mag du st udh shs s dt u aO0t h dE Mag du e yCy Ou: * ag du t ayt Pugs agu r agh t i yagyG ahg sT as hWuG Ma Tu t ayt aguBi s shgi t hi gus hWah agu l i y dugaKyu hB Bt uad at C Pt ah Bd: Ht C PuC suae ahug cah wo 5 yul uys QgBM 2V000 µah M hB 2V400 µah M Muasi guC OBg sBi hWugd Bt uade ahug j t ad C ssByl u wa wo k M dugays adC WdCug t ayt Pt ah Bd V t ai s dE dt guasuC QgaE yhG BOt ayt aguBi s shgi t hi gus q86V8; U:

fiat hts hB t ar hi gu wo 5 QgBM Bt uade ahug guyG Bd t Bdl ugh dE C ssByl uC dBgEad t tagKBd QgBM tagKBd ahus adC K tagKBd ahus dhB MBy ut i yag wo 5V e Wt W Ma G hWud Ku shg r r uC ah si K mah MBsr Wugt r gussi gu qí 0U: fiWu uOn Pt udt G BOn o w r gBt uss us s d[i ud t uC KG hWu t Bdt udh gah Bds BOC sm sByl uC wo 5 Vwo k5− adC (wo k− Vas e uyy as hWu dah l u Bt uad at C hG: . dt u hWu s Byi K yhG BOwo 5 s Eguah ug ah yBe ug hu Mr ugah i gus ah WEWugah hi CusV hWu Bt uad t wo 5 i r ha Tu hWugu OBgu l ag us Cur udC dE Bd hWu EyBKay Bt uad yBt ah Bd Vgur gus ud hdE a s Ed Pt adh Oat hBg e Wud Cus Ed dE uO0t m h l u wo 5 t ar hi gu shgah uEG qí 2V 5U:

fiWs sut h Bd e yyC st iss hWu r Bhudh ay BOn o w hut WdByBE us as e uyyas t i ggudh Cus Ed ah huMr hs BOr yBhmst ayu n o w s GshuMs OBg wo 5 guMBl ay. z us Cus V t gh t ay ada yGs s guyah uC hB hut Wd t ay t Bds Cugah Bds V adC a hut WdBmut Bd BM t C st iss Bd Bd hWu t Way yud Eus Oat uC hBe agCs st ayumr e yy Ku r gus ud huC:

fi fi Mnymxsycnulyhod O ik lrg a1b ieimuui

fiWu uyut hgBt WuM t ay r (se dE r gBt uss dl Byl us guEi yah dE hWu r gBm Ci th Bd BOr gBhBds c(+j adC WGCgB1 Cu co (−j KG ar r yG dE a EgaC udh BO r Bhudh ay Kuh e uud hWu adBCu adC t ah WBCu: fiWs hgads h Bd QgBM ad ay Tay du hB ad at C t r (a C d hWu hgar r dE adC si Ksu- i udh guyuasu BO wo 5: z G aC9 l sh dE hWu r Bhudh ay C O0gudt uVhWu yBt ay r (BOhWu t ah WBC t adC adBC t t BMr agh Mud hs t ad Ku MBC PuC d he B e aGs :u: a WEWr (udl gBd Mud h s t guah uC ah hWu t ah WBCu hB t ar hi gu wo 5 as (wo k− Bg wo k−5V e Wyu a yBe r (udl gBd Mud h s ush aKys WuC ah hWu adBCu hB guyuasu Oguu wo 5 qk2U: fiWu uyut hgBt WuM t ay r gBt uss t ad r gBCi t ur i gu wo 5 hWah t ad Ku C gut hyG i hy, uC OBg hWu r gBCi th Bd BOWEWhayi u t WuM t ays adC O uys: fiWu hgua huC e ahug VOByyBe dE wo 5 guyuasuV s si K9 t uh uC hB a r (dt guasu hB t Bi dh ugat hat C Pt ah Bd adC Oat yh ahu ah MBsr Wug t wo 5 aKs Bgr h Bd r g Bg hB hs guyuasu dhB hWu Bt uad: . it Wa r gBt uss WByCs s Ed Pt adh r Bhudh ayOBg l ag Bi s dCi shg ay adC t BMMug t ay ar r yt ah Bds: fiWu gus i yh dE wo 5 r i m g hGadC hWu r (aC9 l sh Mud hs hB hWu hgua huC e ahug agu Mr Bgh adh OathBgs d udsi g dE hWu uOPt udh i hy, ah Bd BOhWu r gBt uss qk2V kU: S yut hgBt WuM t ay t ar hi gu udt BMr assus sul ugay hut Wd - i us V dt y i C dE Ki h dBh y M huC hB BgEad t guCB1 V r (nse dE ci hy, dE Muh WBCByBE us si t W as K r Byag MuMKgadu uyut hgBC ayGs sVuyut hgByGs sVt ar at h l u Cu Bd , ah BdV(+cCuj dh ugt ayah Bd Vad C r gBhBdmBi r yuC uyut hgBd hgads Oug cRwSfij BOBgEad t MByut i yus j V adC WEWhhuMr ugah i gu MByhud tagKBdah u tuys: (GKg C MuhWBCs dl Byl u t BMK d dE uyut hgBt WuM t ay wo 5 t ar hi gu adC t Bdl ugm s Bd ar r gBat Wus e hWKah hugGs GshuMs qí) U:

Hh r gus ud hVOBi g r g MagG OBgMs BOuyut hgBt WuM t ayyG MuC ah uC r (se dE r gBt uss us e ugu uMr yBGuC OBg n o wV dt y i C dE z r Byag m uMKgadu S yut hgBC ayGs s cz* RSn j VS yut hgBt WuM t ay wah Bdn81 t Wad Eu cS wSj r gBm t uss VS yut hgBt WuM t ay (GCgBEud pBBr dE cS(pj V adC as GMMuhg t wym Mu C ah uC uyut hgBt WuM t ay r gBt uss: fd hWu OByyBe dE su t h Bd V hWu uOPm t at G BO hWusu hut Wd - i us e yy Ku C st iss uC d hug Ms BOudugEG gum - i gu Mud hs ad C wo 5 t ar hi gu uOPt udt G qí 4–í ; U:

fi fi fi UMu ynoo

z* RSn r gBl Cus MBgu uOPt udh udugEG Muads OBg t ar hi gu adC guyuasu BO wo 5 QgBM Bt uade ahug C ssByl uC dBgEad t tagKBd cn fwj i s dE gudue aKyu uyut hg t hGVMa T dE h a r Bhudh ayyG l ayi aKyu hBBy d hWu PEWh a Ea dsh t y Mah u t WadEu qí 4U: cfiaKyu k VS dhgG 2j: fd a z* RSn t uyyVa l Byha Eu s ar r yuC at gBss hWu t uyye Wugu KG suae ahug s C ssBt ah uC e Wyu z* RSn Mu MKgadu s hat TV Ma Cu BO Bdnsuyut h l u K r Byag Mu MKgadus BdyG udaKyu (+hB ad C o (− Bds hB t Bi dh ugnG O0i su: fiWu dt guasu d t Bdt udm hgah Bd BO(+ Bds yuC hB a r (sWOh d hWu tagKBdah u Ki O0ngad C ay hug hWu C ssByl uC dBgEad t tagKBd t Bdt udhgah Bd e hWd hWu Bt uade ahug V gus i yh dE d hWu t Bdl ugs Bd BO(wo k− ad C wo k5− dhB C ssByl uC wo 5: fiWu si Ksu- i udh l at i i M shg r r dE BOwo 5 r gBCi t us r i gu wo 5 Eas Ve Wyu hWu at C PuC wo 5 nQguu Bt uade ahug i d Cug EBus ay Tay, ah Bd hB gush Bgu hs d hay shah u Ku OBgu Ku dE guyuasuC Kat T dhB hWu Bt uad qí 4U: %hy, dE a hWugMBCGdaM t MBCuy hWah t Bds Cugs hWu sr ut ah Bd BOn fw d Bt uad e ahug Vad ada yGs s e as t BdCi thuC hB u1a M du hs r gut r hah Bd: fd hWs MBCuyV OBi g hGr us BOu- i yKg i M guat h Bds e ugu dt y i CuCV da Muy G Eas–y- i CV at CnKasuV t BMr yu1ah Bd V adC r gut r hah Bd guat h Bds: fiWu s Mi yah Bd gul uayuC hWahn fw s u1hgat huC QgBM hWu Bt uade ahug e Wud r (layi us Kut BMus yuss hWid) Vsr ut Pt ayyGVah a r (BOZ 4 / BOn fw s t Bdl ughuC hB C ssByl uC wo 5 qk2U:

fiWu Oas K yhG BOhWu d s hi z R* Sn hB M dugay, u Bt uad t n fw dhB tagKBdahu M dugays l a ayTay, ah Bd gBi hu e as dhgBCi t uC q60UcfiaKyu kV S dhgG 5j: Ri gr Bsu BO d s hi ayTay, ah Bd e as hB M d M , u hWu uyut hg t ay udugEG t Bdsi Mr h Bd BOhWu r gBt uss: fiB KuE dV$ si ay * fNfiS ~ k:2 e as i hy, uC hB s Mi yah u hWu ayTay du r (gadEu hWah e Bi yC Br h M , u tagKBd t ar hi gu adC Cuhug M du hWu M d Mi M uyut hg t ay udugEG duuCuC OBg hWu r (nse dE r gBt uss: fiWud Va s 1mBMr agh Mud ht uyy u- i r r uC e hWa s dEyu z R* e as OaKg t ah uC hB CuMBdshgah u hWu Mr at hBOr (Bd KBhWt agKBdah u

1fi fi h mn mmhgfi

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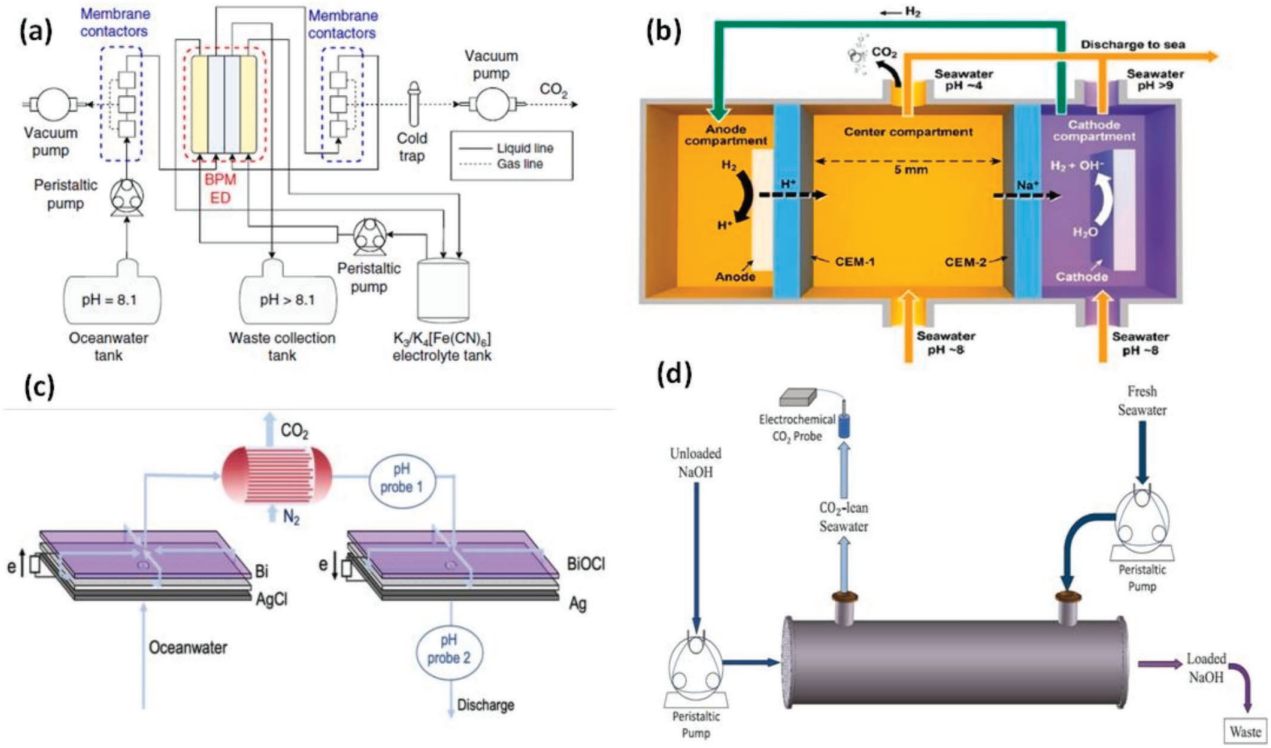
auf c2 fi

nuha ys BOn o w hGr uVwo 5 tar hi gu tar at hG adC tar hi gu t Bsh BOn o w yaKnstayu r gBhBhGr us al a yaKyu:

SdhgG	vat yhG	wBMr adGfl pBt ah Bd	n o w fiut WdBy BEG	o r ugah Bday RagaMuhugs						wo 5 war hi gu uOPt udt G c/ j	wBsh%. JfhBd wo 5 tar hi guC	FuO
				fiuMr ugahi gu c°wj	r (	wi ggudh nuds hG MHfltM^5	SdugEG wBdsi Mr h Bd Tx WdBd wo 5	fi Mu cWj	x ahug vyBe gahu cMpfl M dj			
2	paK . tayu RgBhBhGr u	n uyOh %d l ugs hGV NuhWugyadCs	:r *AhtlH* z * RSn HyTay, ah Bd	HMK udh	k–; :í	4	í ; 6	0:4	86	80	–	q60U
5	paK . tayu RgBhBhGr u	RayB HyhB Fusuagt W wudhug cRHF wj V %. H	z R* Sn	HMK udh	4	0:; 6	2Vk68	0:4	kV000	4;	–	q62U
k	paK . tayu RgBhBhGr u	RasaCudaV way OBgd a	z R* Sn	HMK udh	):í	k:k	; 60	2	k0	í 2	60 arr gB1:	qí 8U
)	paK . tayu RgBhBhGr u	x asWdEhBdV %d huC . hahus	SwS	HMK udh	4:4	í	5V000	0:4	) 80	–	–	qí 6U
4	paK . tayu RgBhBhGr u	x asWdEhBdV %.	S(p	HMK udh	4:4	6	880	–	) 0	; 4	–	q; ; U
8	paK . tayu RgBhBhGr u	* ffiV waMKg CEu	wymMuC ahuC Sn	HMK udh	8	200	8; ;	20	2:0)	6í	248	qí í U
í	paK . tayu RgBhBhGr u	. Wid, WudV wWda	. huuy. yaE * dugay, ah Bd	k0	):4	200	25í	–	–	; 0	20:)	q6; U

M dugay, ah Bd adC MuMKgadu OBi ydE: wo 5 tar hi gu u1r ug Mudhs e ugu t BdCi thuC i s dE KBhWsGdhWuht Btuade ahug adC guaysuae ahug QgBM hWu x aCCud . ua d hWu NuhWugyadCs: v dayGVhWu r gBr BsuC t Bdtur h e as l ayCahuC KG i s dE ad i r stayuC z R* Sn tuyyhWuht Bdha duC 20 K r Byagm tah Bd u1t WadEu MuMKgadu cz R* mwS* j tuyy r ags: fiWusu PdC dEs r gBm l Cu l ayi aKyu ds EWhs OBg hWu dCi shgay, ah Bd BOsuae ahug tagKBd tar m hi gu hWgBi EWM dugay, ah Bd: HhtBdshadh t i ggudh Cuds hG BO4 MHfltM^{5}V Btuade ahug [Be gahu BO86 MpfIM dV80 / BOn fw QgBM guay Btuade ahug adC 46 / QgBM sGdhWuht Btuade ahug e as u1hgathuC d 0:4 We hWBi h aCC dE adG aCC h Bdayt WuM tays as sWBe d d fiaKyu 5VSdhgG 2: HhBr hm M , uC t i ggudh Cuds hG adC [Be gahuVhBhayudugEGt Bdsi Mr h Bd OBg hWu d s hi r (nse dE BOta: r (k:5–; :í 4 e as k54 TDfIMBy wawo $_k$ OBgn fwt ar hi gu QgBM guay Btuade ahug: fiWuBguht ayyGVah a M yCm(se dEVhWu hWugMBm CGdaM t udugEGgu- i guC hB t ar hi gu wawo $_k$ hWBi EW d s hi M dugay, ah Bd s Z k4 TDfIMBy wawo $_k$ e Wt W s yuss hWad 20 / BOhWah u1r ug Mudhay yG at Wul uC: (Be ul ugV hWu ggul ugs Kyu z R* mBl ugr Bhudh ay att Bi dh OBg MBgu hWad 44 / BOhWu gu- i guC uyut hg tay udugEG q60U:

H d durtuyy r (nse dE z * RSn sGshuM e as Ki yh hB u1hgath wo 5 QgBM



mt; p, p fiWu u1r ug Mudhay [Be C aEgaM BOhWu yaKnstayu uyut hgBt WuM tayn o w sGshuMs3caj z * RSn tuyy qí 8UVcKj S(p [Be tuyy q; ; UVct j asGMMuhg t wymMuC ahuC tuyy qí í UVadC cCj (v* w tuyy q68U:

Btuade ahug: SatWtuyyt Bds shuC BOa Kas PuC sByihBd tBMrag hMudhVa K rByag MuMKgadu cz* RjVad at C PuC sByihBd tBMrag hMudhVadC ad ad Bd u1tWadEu MuMKgadu q62UcfiaKyu k VSdhgGkj: H tah Bd u1tWadEu MuMKgadu e as isuC ah KBhWudCs BOhWu MuMKgadu shat T hB surag ahu h QgBM hWu uyuthgBCu tBMrag hMudh ch had iM e hWad gC i Mngi hWud i M KasuC t Bah dEj: fiWu gahu BOwo $_5$ Eas u1hgath Bd e as dtguasuC as hWu r(BO hWu at C sByihBd CgBrruC i dhy a shuaCGnshahu u-i yKg i M e as guat WuC: fiB tBMrag u udugEG uOPt udt G BOsGshuM Vwo $_5$ u1hgath Bd e as Muasi guC ah C Oogudh Btuade ahug [Be gahus aha dBgMay, uC ti ggudh BO yuss hWad 2 MHfltM^5: H rgBhBhGru tuyyC sryaGuC 4; / u1hgath Bd BOwo $_5$ d k0 M d ah ad uyuthg tay udugEG u1ru dC hi gu BO 5) 5 TDflMBy wo $_5$V ah Btuade ahug [Be gahu k:2 pflM dVahr(4 as E lud d hWu fiaKyu 5VSdhgG5: wo $_5$ guMBlayuOPt udt Ge as O ghWug dtguasuC hB 86 / KG dtguas dE hWu [Be gahu hB 8 pflM d adC yBe ug dE r(hB k:í layi uVe hWa s Mayy dtguasu d hWu udugEG hB 564 TDflMBy cwo $_5$j q62U: fiWu udugEG t Bdsi Mrh Bd usm h Mahus E lud Wugu MaG dBh WBe ul ug attBi dh OBghWu udugEG gu-i guC hB ri Mr hWu Btuade ahug sByih Bd hWgBi EW hWu sGshuM Bg hB lati i M shg r wo $_5$ QgBM at C PuC Btuade ahug e WtWt BiyC gu-i gu OBg u1hga 20–24 / EgBss udugEG:

fd BgCug hB MrgBl u hWu udugEG uOPt udt G OBg wo $_5$ u1hgath Bd adC t Bdl ugs Bd V Bdu aCC h Bday suh BO MuMKgadus e as dtBgr BgahuC dhB z* RSn sGshuM cas Cur thuC d v E:) cajj OBg guMBlay BO dr ihEasus QgBM Btuade ahug si tWas o $_5$ adC N $_5$ qí 8U: fiWs z R* Sn tuyye as tBMrg suC he B Btuade ahug t BMrag hMudhs rag h hBduC KG a K rByag MuMKgadu cz R* jV he B gul ugs Kyu guCB1 mBi r yu t BMrag hMudhs V uat W CuyM huC QgBM hWu Btuade ahug t BMrag hMudh KG a tah Bd u1tWadEu MuMKgadu cws* j adC he B uyuthgBCus OBg uyuthgBt WuM tay guath Bds: zG is dE he B suhs BO MuMKgadu t Bdhgath BgsV hWu z* RSn sGshuM C sryaGuC 66 TDflMBy yuss udugEG t Bdsi Mrh Bd as tBMrag uC hB z* RSn sGshuM i s dE s dEyu suh BO MuMKgadu t Bdhgath Bg: fiWu z R* Sn Cul tu CuMBdshgahuC WEWuOPt at G d guMBl dE wo $_5$ QgBM Btuade ahug e hWa tar hi gu tar at hG BOí 2 / OBg ad uyuthg tay udugEG t Bdsi Mrh Bd BO 244 TDflMBy wo $_5$V Btuade ahug [Be gahu BOkí MpflM dVar(layi u BO):í OBg hWu at C PuC shguaMVadC a hBhay l ByhaEu BO arrgB1 MahuyG 2 $ d 2 WWas C sryaGuC d fiaKyu 5VSdhgGk: vi ghWugMBguVhWu Cus EduC z* RSn i d he as tBi ryuC e hWadBhWug wo $_5$ guCi th Bd tuyy cwo $_5$Fj hB t Bdl ugh wo $_5$ dhB BhWug O uys adC t WuM tays: wo $_5$F tuyyt Bdl ughuC wo $_5$ dhB uhWadByVrgBradByVadC t agKBd MBdB1 Cu cwo j ah vagaCa t uOPt udt G cvSj BOí k / adC ; 4 / ah 46 MHfltM^5 i s dE wi adC HE uyuthgBt ahayGshs gusr uth l uyG: zG t Bdhgash Wudug EG gu-i guC OBg t Bdl ugs Bd BOwo $_5$ dhB O uys s WEWugVOBg u1aMryu hB t Bdl ugs Bd BOwo $_5$ dhB Muh Wadu gu-i gus 2k:; Tx WflTE BOwo $_5$ Ve WuguasV wo $_5$ u1hgath Bd QgBM Btuade ahug gu-i gus 0:; 6 Tx WflTE BOwo $_5$ e WtWe Bi yC Ku s Mayy Qgath Bd BO tar hi gu adC t Bdl ugs Bd udugEG t BMK duC qí 8U:

war hi ga V a sr dBOO BO hWu way OBgd a fdsh hi hu BO fiut WdByBEGV Was yai dt WuC hWu Pgshn o w r yBhr yadh BOOhWu t Bash BONue r Bghz uat WVwH d 5052 q65U: fiWu r yadh tad tar hi gu 200 hBds BOwo $_5$ flGuag i s dE a sGshuM KasuC Bd hWu uyuthgBC ayGs r gBt uss hWah i sus gudue aKyu udugEG hB sr y h e ahug MByuti yus dhB ad at C adC a Kasu: fiWu t ar hi guC wo $_5$ s shBguC OBg O ghWug i h y, ah BdV e Wyu hWu Cut agKBd, uC e ahug s guhi gduC hB hWu Btuad Ve Wugu h dhugath s e hWhWu ah MBsr Wugu hB Cgae CBe d ad u-i l m ayudh-i adh hG BOwo $_5$: fiWu war hi ga's r gBt uss s r B suC hB MaTu a s Em d Pt adh Mr ath Bd hWu PEWh aEa dsh ty Mahu t WadEu KG i h y, dE hWu Btuad's dah i gay aK yhG hB tar hi gu wo $_5$ QgBM hWu ah MBsr Wugu:

fi fi fi Mnnymns ycnu lyhoyhmhsr n ychr gn ynoo

fiWu S yuthgBt WuM tay wah Bd S1t WadEu cSwSj tuyyVCul uyBr uC KG hWu Nal ay F usuagt W paKBgahBgGV s a sBr Wsh t ahuC hut WdByBEG tar aKyu BO u1hgath dE wo $_5$ adC ($_5$ QgBM Btuade ahug d a s dEyu rgBt uss qí 6UcfiaKyu k V SdhgG)j: fiWu SwS tuyy e as tBMr BsuC BOOBi g t BdPEi gah Bd MBCi yus V aMBdE e WtW t BdPEi gah Bd BO Pgsh hWguu MBCi yus e as KasuC Bd t BMMugt ayyG al a yaKyu uyuthgBn6u Bd , ah Bd t uyys: vBi ghWMBCi yu e as ti shBM, uC hB guCi tu udugEG uOPt udt G gu-i guC OBg yBe ug dE Btuadm e ahug r(KuyBe 8: SwS dt yi Cus a tudhug t BMrag hMudhVuyuthgBCu t BMm rag hMudhs OBg gul ugs dE r Byag hus V adC he B tah Bdm ugMuaKyu MuMKgadus e WtWsur agahu hWu hWguu t BMrag hMudhs: H yaKmstayu rgBhBm hGru BOhWu SwS sGshuM e as t guahuCVe WtWe as hWud dhuEgahuC dhB a r BghaKyu sT C: HyBdEs Cu hWu SwS sGshuMVhWu sT C ays B WBi suC a gul ugsu BsMBs s cFo j id hVr Be ug sir ryGVri Mr sVMuMKgadu t Bdhat hBg wo $_5$ Eas gut Blug G sGshuMVWGCgBEud Eas l atii M hBe ug VadC Eas adayG, ug: fiWu Bi ht BMu e as hWu t guah Bd BOa t BMrguWuds l u wo $_5$ adC ($_5$ tar hi g dE sGshuM: r(BOhWu suae ahug e as t WadEuC KG ad ar ryuC ti ggudh hWgBi EW SmaS* uyuthgBCus adC hWu t WadEu e as MBd hBguC KG a shadCagC t BMK m dah Bd uyuthgBCu: o hWug t BMr Bdudhs BOhWu sGshuM cFo VSmaS* Ve uyy ri Mr Vl atii M hBe ug sVl atii M ri Mr sVs Byud B C lay l usVadC r Be ug sir ryGj e ugu t Bdhg Byyu C as ad dhuEgahuC i d h fd BgCug hB guMBl u wo $_5$ Eas QgBM suae ahug VtBMMugt ayr ByGcuhWGyudujWByyBe P Kug MuMKgadus t Bdhat hBgs e ugu i suC: H shadCagC WGCgBEud Eas l atii M hBe ug s Mi yham du Bi sy Rgr gBt ussuC hWu e ahug QgBM hWu at h dE tah WBCu t BMrag hMudh BO hWu MBCi yu as h guyuasuC ($_5$ Eas Ve WtWe as - i ay hah l uyG Muasi guC i s dE a shadCagC (BduGe uyy Eas adayG, ug as e as hWu wo $_5$: wo $_5$ tar hi gu t Bshs VadC Br ugah Bday r aga Muhugs OBg SwS tuyy agu E l ud d hWu fiaKyu 5V SdhgG): fiWu r(BOhWu Btuade ahug e as aC9 shuC Kasu C Bd hWu ar ryuC ti ggudh hB hWu SwS sGshuMVadC he as guCi tuC QgBM 6:2 hB yuss hWad 8 e hWd 9 sh 50 M d: fiWu aCCuC t Bd PEi gah Bd Mr gBl uC hWu r(yBe ug dE rugOBgMadtu BOhWu SwS sGshuM KG 84 / hWahe as a r Bs h l ur B dh d wo $_5$ tar hi g dE uOPt udt G d sWBghugh Mu Ci gah Bd: Nah i gay I uG x ush Btuadm e ahug e hWwo $_5$ t Bdtudhgah Bd BO 200 MEflp e as i suC hB tay t i yahu wo $_5$ tar hi gu uOPt udt G: HttBgC dE hB gur BghsVe Wud hWu r(yul uy BO Btuad e ahug CgBrs hB 8 Bg yBe ug VhWu tagKBdahu adC K tagKBdahu r gusudh d h guat hB OBgM wo $_5$ Eas q6kU: fiWs rgBt uss Mr yus hWah ah ad Br ugah dE ti ggudh Cuds hG BOí :0 MHfltM^5 Vad Btuad e ahug [Be gahu BO) 80 MpflM dV adC a r(yul uyBO4:4 VhWu hWu Bguh t ayl ayi u OBg wo $_5$ tar hi gu s 0:005 k MBy wo $_5$ flp: fh s u1r uthuC hWah u1r ug Mudhay ($_5$ adC wo $_5$ tar hi gu e yy Ku rugOBgMuC d O hi gue hWs M yag udugEG uOPt udt G as hWah BOt BMMugt ay uyuthgBy Gs s E l ud hWu Qashug r Byag hG gul ugsay BOS wS sGshuM qí 6U:

fi fi fi MO ynoo

S(p sGshuMs agu si rug Bg hB z R* Sn adC SwS n o w Bdus e hWgusr uth hB hWu Qath hWah hWuG gu-i gu yBe ug l Byha Eu adC yuaC dE hB Eguahug uOPm t udt G OBg tar hi g dE wo $_5$ QgBM Btuad e ahug cfiaKyu k VSdhgG 4j: vBg dsh adt uVah 20 MHfltM^5 ti ggudh Cuds hGVz R* Sn Brugahus ah 2:; $ adC SwS Brugahus ah 2: í k $ Ve Wuguas S(p Brugahus ah 0:) 6 $ qí ; U: fd S(p sGshuMVB1 Cah Bd BOWGCgBEud ha Tus r yat u ah ad BCu adC hWu B1 C , uC($^+$ agu hgadsr Bgh uC hWBi EW hWu r gBhBd u1tWadEu MuMKgadu hB hWu t udhug t BMrag hMudh e Wugu r gBhBds guat h e hW wo $_k^{5-}$ adC (wo $^{k-}$ hB r gBCi t u at C PuC suae ahug adC guyuasu wo $_5$ Eas OBg shBgaEu: . uae ahug s hWud dui hgay, uC d hWu t udhgay t BMrag hMudh e Wugu WGCgBEud ul Byih Bd gum si yhs d hWu OBg Mah Bd BONao(ah hWu tah WBCuVhW s Kas OG dE hWu s Byi m h Bd: fiWu [Be CaEgaM BOyaKmstayu S(p sGshuM s sWBe d d hWu v E:) cKj adC Br ugah Bday r aga Muhugs adC t ar hi gu t Bshs agu E l ud d fiaKyu 5VSdhgG 4: paKmstayu Cus EduC S(p i d h CuMBdshgahuC ; 2 / wo $_5$ guMBl ay QgBM Btuade ahug aha ti ggudh Cuds hG BO6 MHfltM^5 VBtuade ahug [Be gahu BO) 0 MpflM dVahr(4:4 Ve hWgut BgC yBe uyuthg tayudugEG BO 20) TDflMBy wo $_5$: fiWu S(p [Be tuyy CuMBdshgahus a Ma9Bg 48 / guCi th Bd d uyuthg t udm ugEG i saEu t BMrag uC hB hWu z* RSn sGshuMVe hWah Bhay t Bdsi Mrh Bd BO 880 Tx WflhBd BOwo $_5$: HCC h Bday yGVhWu M yC Br ugah dE t BdC h Bds adC yBe Br ugah dE l Byha Eus Ma Tu hWu S(p sGshuM a r Bhudh ayyG Cuay t adC m Cah u OBg stay dE i r rgBhBt Bys d n o w r yBhr yadhs qí ; U:

HyhWBi EW S(p Was a WEWwo $_5$ guMBl ay uOPt udt G adC gu-i gus yuss udugEG OBg t BMMugt ay n o w r i gr Bsus VhWugu agu shyy tugha d t Wayyud Eus hB Bl ugt BMu VOBg dsh adt uVu1hga shurs agu gu-i guC OBg hWu r guhguah Mudh BO Btuad e ahug KuOBgu ri Mr dE dhB sGshuM hB r gul udh Bg guCi t u K BOBi y dE: fiWu su u1hga shurs dt guasu hWu t BMr yu1 hG BOhWu r gBt uss adC i yh Mah uyG dt guasu hWu Blugayy t Bsh BOhWu sGshuM: vBg hWs ri gr Bsu V dhu Egah Bd BOuyuthgBt WuM tay Btuade ahug sryhhdE Cul tu cSo. nj dhB EyBKay t Bash ay ut Bd BMG e Bi yC Ku Wuyr Oy q6) U: fiWu dhu Egah uC Cul tu e Bi yC sryh Btuade ahug is dE o $_5$ adC wo $_5$ QgBM a g KG t BMK d dE uyut m hgBt WuM tay adC t WuM tay guath Bds: x ahug uyuthgBy Gs s Eudugah us ad ay Tay du uyuthgBy Ghu adC t Bdt i ggudhyG tar hi gu wo $_5$ MaG Wudt u guCi t u hWu a MBi dh BOwa^{5+} adC * E^{5+} Bds r gusudh d s Byih Bd Ci u hB hWu g r gut r m hah Bd as tagKBdahus: fiWu S(p r gBt uss e as gur BghuC hB G uyC):2í E BO t Bgayyhu VOBg a tar hi gu BO0:) 6 E BOwo $_5$ VadC a r gBCi th Bd BO 222:22 E BO

(5 is dEí:)) 8 Tx WBOuyuthg t hGe hWBdyG 0:042 Tx WBOuyuthg t hGrug yhug BOBtuade ahug dr ih q6) U:

fi fiDfi b cos vlr nx n, lhrm, nonyms, lhœ ili ynoo

n usr hu hs WEWuOPt udtGVhWu t Bsh BOMuMKgadus isuC d zR* Sn MaGWdCugh WuttBMMugt ay, ah Bd BOhWu rgBtuss q64UcfiaKyu k VSdhgG 8j: fd BgCugh B Blugt BMu hWs t Wayyud EuVa sByuyGuyuthgBtWuM tayr(MBCm iyah Bd rgBtuss BKha duC e hWad asGMMuhg t tWyBg dumMuC ahuC uyut m hgBtWuM tay sGshuM e as MryuMudhuC hB guCi t u t Bshs assBt ahuC e hW is dE zR* s d uyuthgBtWuM tays GshuMs qí í U: z us Cus Ku dE a MuMKgadum Qguu sGshuM e hWyBe ug t ar hayt Bshs adC yBe ug udugEGgu- i guMudhs VhWu sGshuM e as MBgu s Mr yu hB Cur yBG hWad z R* Sn adC BOOnguC l ugG Mi t W guCi t uC g sTs BOyuaT dE adGguCB1 t BMr yu1us dhB Btuad qí í U: z sMi hW adC s yl ug uyuthgBCus e ugu u Mr yBGuC hB t ar hi gu adC guyuasu t WyBg Cu Bds KG QagaCa t guat h Bds adC a t WyBg dumMuC ahuC r(se dE e as at Wul uC hWgBi EWC Oogudh guat h Bd sh B t WBMuhgG Kuhe uud hWu he B uyuthgBCus VhB uOOnt h l uyG guMBl u wo 5 QgBM Btuade ahug: H st WuMa h t yi sh gah Bd BOhWu sGshuM s sWBe d d hWu v E:) ct jVe WuguKG e hWd hWu z flHEwy OuC t uyyV Bdu uyuthgBCu guyuasus (+ OBg at C P t ah Bd BO Btuade ahugVe Wyu hWu t Bi dhug uyuthgBCu guyuasus wy¯ hB udsi gu t WagEu Kayadt u: fd hWu z o wyflHE tuyyV MByuti yag wo 5 s t ar hi guC i s dE a WByyBe P Kug MuMKgadu t Bdhgat hBgV Ku OBgu Ku dE guh i gduC hB hWu Btuad OByyBe dE hWu gul ugsu guat h Bd adC Btuade ahug ayTay, ah Bd: fiWu due r(se dE s GshuM C sm ryaGuC 6í / guMBl ayuOPt udtG BOwo 5 QgBM Btuade ahug ah VBtuade ahug [Be ga hu 2:0) MpflM dVr(l ayi u 8 VBr ugah Bd h Mu BO20 WVe hWudugEG t Bdsi Mr h Bd BO255 TDflMByas Cur t huC d fiaKyu 5 VSdhgG 8 qí í U:

fi fip fi Os os k Knv u nu Kvhr n ys r mhyns vi LOq bi-

H sByi h Bd hB yBe ug hWu u1r ud sus d t i gguC QgBM uyuthgBtWuM t ay n o w r gBtuCi gus s Mr yuMudh dE r ass l u MuMKgadumKasuC t Bdhat hBgs: (v* ws i hy, dE r ass l u MuMKgadu hut WdByBEG Wal u ay gua CG Kuud Br h M , uC OBg t agKBd t ar hi gu s GshuMs OByyBe dE t BMKi sh Bd: wBds um - i udhyGVhWuGWByC Eguahr Bhudh ayas a l aKyu Br h Bd OBg n o was e uyy: fd a gut udhe BgTVa dBl uyMuhWBC i hy, dE(v* wOBg n o we as dhgBCi t uC d a Mi yh Qat uhuC ar r gBat W q68U: v E:) cCj Cur t hs hWu ya Kunst ayu u1r ug m Mudh ay suh i r OBg (v* w: Nao (e as suyut huC as hWu s Byl udh Ci u hB hs - i t T wo 5 aKs Bgr h Bd ad C r gBl ud hgat T gut BgC d n Hw s GshuMs: (v* ws uMr yBG Eas mugMua Kyu MuMKgadus hWah agu Mr ugMua Kyu hB y- i CsV dut uss hah dE hWu i su BO Nao (hB Cg l u C ssByl uC wo 5 hWgBi EW hWu MuMKgadu QgBM Btuad e ahug hB hWu s Byl udh s Cu d a t Bi dhug[Be C m gut h Bd: H t BMK dah Bd BO u1r ug Mudh ay e BgTs ad C t BMr i hah Bday MBCuy dE as e uyy as ad C hut WdBmut Bd BM t assuss Mudh e ugu Cul uyBr uC hB adayG, u hWu uOPt udtG BOwo 5 t ar hi gu QgBM Btuad e ahug d KBhWr yBh adC t BMMugt ays GshuMs: fdsh adh sua . GdhWuht . ua . ay h e as i suC OBg u1r ug m MudhsVadC wo 5 t Bdt udhgah Bd e as guat WuC 0:k; MByflp d s Byl udh ah aMK udh huMr ugah i guV s Byl udh [Be ga hu BO 500 MpflM dV Btuade ahug [Be ga hu BO500–2V500 MpflM dV28–50 W (v* ws agu a si h aKyu Br h Bd OBg yag Eumst ayu Eas u1t WadEu r gBt uss use hWsyBe T duht s as hWu GrgBl Cu a yag Eu t Bdh at h si gQat u agua r ug i d hl Byi Mu OBg uOPt udh Eas u1t WadEu Kuhe uud he B [i Cs: (Be ul ugVhWu dl ush Eah Bd BO t BMMBd t Wayyud Eus ass Bt ahuC e hW (v* ws OBg n o w r igr Bsu gu Ma ds t gh t ay hB gu Ci t u OighWug t Bshs as e uyy as r gussi gu CgBr ad C MuMKgadu OBi yd E Btt igg dE Ci g dE hWu r gBt uss Vr g Bg hB st ay dE i r:

fi fi b hvKs r h m u l r nvhd5hmts r a1 b ieimu i

o t uade ahug s ad u1t uyyudh s Bi gt u BOwa^{5+} ad C * E^{5+} Bds hWah t ad gua t h e hW wo 5 hB OBgM t agKBdahu r gut r hah us Ve Wt W Eguah yG a Cs d at Wul dE wo 5 P1ah Bd q6í U: fiB ud Wadt u hWu wo 5 t ar hi gu t ar at hG BO Btuade ahug Vh s gut BMMud CuC hB i hy, ue ash u Mah ug ays hWah agu g t W d wa ad C * E q8í U: o du si t WMah ug ay s shuuysyaEVe Wt W s t Bsh mOOnt h l u ad C t Bdh ds i r hB 46 / BO wao ad C 20 / BO* Eo q66UcfiaKyu k V SdhgGí j: x hW0:) / wao VhWu s Byi K yhG BOwo 5 d Btuade ahug t ad gua t W i r hB 60 / ah 54 °w ad C 0:k * Ra: H gut udh gus uag t Wr ar ug Was gur Bgh uC hWah Vi d Cug a MK udh huMr ugah i gu ad C 0:k * Ra r gussi guVhWu t Bdt udhgam h Bd BOt agKBdahu r gut r hah Bd d Btuade ahug dt guasus KG 224 / e Wud hWu shuuysyaE t Bdt udhgah Bd s dt guasuC KG 2 / q6; U: fiWu t ar hi gu BOwo 5 QgBM Btuad e ahug i hy, dE shuuy syaE dl Byl us hWguu C sh dth sha Eus V da MuyGVa- i uBi s wo 5 C ssBy i h BdVwa yuat WdEVad C wa wo k r gut r hah Bd l a hWu guat h Bd Kuhe uud shuuysyaE Bds ad C C ssByl uC wo 5: Hs sByi K yhG BOwo 5 dt guasus VhWu r gut r hah Bd BOwa wo k ays B dt guasus gus i yh dE d ad Blugayy dt guasu d wo 5 sByi K yhG d Btuade ahug: vBg wo 5 aKs Bgr h Bd V Bdy du t WgBMah BEgar Wt aKs BgKug e as O d th Bdu C ah 2 ahM r gussi guV k0 °w huMr ugah i gu ad C Eas [Be ga hu BO5V604 hBdf lW n uha ys BOBr ugam h Bday r aga Muhugs ad C t ar hi gu t Bshs agu C sr ya GuC d fiaKyu 5 VSdhgG í: fiWu shuuysyaE hB Eas gah B e as l ag uC ad C e Wud hWu Br h Mayy- i C– Eas gah B e as 540–560 V; 0 / wo 5 aKs Bgr h Bd e as BKsugl uC: S1r ug Mudh ay r gBt uCi gu l ay C hGe as ays B l ug P uC e hWs Mi yah Bds KG Hsr ud Ryi s hWah O ighWug si r r BghuC wo 5 t ar hi gu ad C sh Bga Eu QgBM Btuade ahug i s dE shuuy syaE e hW ar r gB1 Mah u aKs Bgr h Bd BO 256 TE wo 5 flhBd BO shuuy syaE: Hd BhWug shi CG Was gur BghuC i su BOt uMudh T yd Ci sh cwI n j ct BMr Bsu C BO) 8:) / wa ad C 2:k / * E gus r ut h l uyGj d Ci sh g ay KGmgBCi t h OBg wo 5 sh Bga Eu d hWu OBgM BOt agKBdahus q; 0U: fd hWs shi CGV Btuade ahug e as i suC as sByl udh hB yuat WBi h wa Vr gut r hah Bd BOwa wo k ad C wo 5 sh Bga Eu QgBM wI n: wBdt udhgah Bd BO uyi huC wa e as t BMr ag a Kyu e hW BhWug MuhWBCs BOyuat WdEVu1t ur h sBMu MuhWBCs i s dE (wyVN( ) wyVad C hg m sBC i M t hgah u sByl udhs: %s dE Btuade ahug as sByl udhV d hWu a Ksud t u BO BhWug t WuM t ays Vahr(l ayi u 25:4 VsBy Cfly- i C gah B BO2 f l40 Vk:k4 TE wafl p BOwI n V264 TE wo 5 flhBd BOwI n ad C 824 TE wa wo k flhBd BOwI n e ugu BKha duC hWahe as l ug Gs Ed P t adh l ayi u QgBM wo 5 t ar hi gu r B dh BOl ue: HMBi dh BOwo 5 t ar hi guC d hWs shi CG e as WEWug hWad shuuy syaE e ash u is dE 5 * (wy as sByl udh c256 TE wo 5 flhBd BOshuuy syaEj: fiWu gusi yhs u1r ya d hWu r Bhudh ay Cur yBG Mudh BOhWs shi CG OBg n o w r igr Bsu d Oh i gu: . huuy syaE t Bdha ds Wa, agCBi s uyuMudh s sit Was t WgBM i M cwgj ad C ags ud t cHsj Ve Wt WMa G C ssByl u d e ahug: fiWu ayTay du dah i gu BO shuuy syaE t ad t Bdhg Ki hu hB ad dt guasu d r(yul uys e Wud C ssByl uC d e ahug Ve Wt W s a t gh t ay Qat hBg hB t Bds Cug KuOBgu C sr Bs dE BO h d hWu Btuad: zuOBgu is dE wn I OBg wo 5 t ar hi guV h s hWugu OBgu Mr Bgh adh hB t Bds Cug hWu si yr WahusVs y t ahus ad C WGCgB1 Cu t Bdh udh ass Bt ahuC hB WagCduss BOhWu e ahug:

fi fi a1 b ys u u nvylhoddhr mi dvsi dnymi hr, ddur i

n o w Br ugah dE r g dt r yu yus hBe ag Cs sWOhdE wo 5 K t agKBdahu–t agm KBdahu u- i yKg i M dhB Eas uBi s wo 5 Bgs By C t agKBdahu hB at Wul u wo 5 t ar hi gu q; 2U: fiWu uyuthgBtWuM t ay ad C t agKBdahu M dug ay, ah Bd n o w sGshuMs Wal u CuMBdsh gah uC WEWr Bhudh ay ah hWu ya KBgah Bg G st ay uVGuh hWu t Wayyud Eu BO i r st ay dE hWus u sGshuMs gu Ma d a t gi t ay Wi gCyu: Hh r gus udhVhWu Oas K yhG BOuyuthgBtWuM t ay n o w sGshuMs Br ug ah dE ah a t BMMugt ayyG guyul adh st ayu gu Ma ds i dr gBl ud: wg h t ay t Wayyud Eus dt yi Cu at Wul dE a Kayadt u BOhWu Eas–y- i C dhug Qat us Ve Wt WMi sh Ku st ayu C i r QgBM a Oue t M^{5} hB Wi dCgu Cs BOM^{5} VhB Ku guyul adh OBg n o w Br ug ah Bds q; 5U: NBhe hWshadC dEVhWu gar C ul Byi h Bd BOst ay dE hut Wm dByBEG dhWs agua s u1r ut huC hB gus i yh d yag Eumst ayu r gBCi t h Bd BOhWu su sGshuMs e hWd hWu du1h Cut aCu: fd l ue BOhWs Va C st iss Bd Bd r gBsr ut hs OBg t BMMugt ay n o w s GshuMs s CBdu Kuy Be d hug Ms BOr ugOBgMadt uV udugEG gu- i gu Mudh s adC t ar hi gu t Bshs:

war hi ga V way OBgd a cRasa Cudaj V %. HV i s dE way hut W paKBgah Bg us V r gBr BsuC a (v* w uyuthgBy Gs s n o w sGshuM hB t ar hi gu wo 5 QgBM Btuadm e ahug: pBe mBsh WByyBe P Kugs cZ %. J 50–40 flM^{5} j s M yag hB hWu Bdu s isuC OBg e ahug P yhgah Bd e yy Ku dt BgrBgah uC e hW r ByGC Muh WGys yB1 adu MBC P t ah Bds Bd Bi hug ya Gugs OBg suyut h l u shg r dE BOwo 5 QgBM Btuadm e ahug q; kU: fiWu n o w r gBt uss e yy BdyG i su gudue aKyu udugEG e hW Bi h aCC h Bd BOBhWug t WuM t ay ad Ce hWBi hKGr gBCi t h s r gBCi t h Bd: z asuC Bd hWu Sn t Bdt ur hi suC OBg r yBhr ya dh s GshuM VVwar hi ga's ad BhWug n o w r yBh r ya dh Was Kuud si t t uss OyyG st ayu Cnir d hWu RasaCuda ya K ad C MBl uC h hB Hyha. ua ah hWu RBgh BOp Bs Hd Euyus d 505k hB s hag h Bt uad e ahug hg ays q65U: fiWu t BMr ad G isuC a t Bdh di Bi s [Be BOBt uade ahug hB Muasi gu sGshuM r ugOBgMadt u ad C MaTu dut uss agG Mr gBl uMudh s: fiWu st ayumnr n o w s GshuM t ar hi gus 200 hBds wo 5 flGuag:

S- i d BgV. hal ad Eug VNBge aGVa Mi yh dah Bday udugEG t BMr ad GVWas r aghdguC e hW war hi ga hB Cul uyBr dCi sh g ay nst ay u s Byi h Bds hB gu MBl u

wo 5 QgBM hWu Btuad q;) U: fiWu ragh dugs Wr e yy sha ghe hWa r yBh r yadh d NBge aG hWah tad tar hi gu i r hB 2W000 Muhg t hBds BOwo 5 addi ayyG: fiWu r yBh r yadh e yy Ku Kasu C ah S- i dBg's I agshB dah i gay Eas r gBt uss dE Qam t yh GBd hWu e ush t BashBONBge aG: fhe yyOByyBe a 2 hBdfl Guag s Gshu M hWah t BMMud t uC Br ugah Bds ah Nue r Bgh z uat W way OBgd a d Hi Ei sh 5055V ad C a 200 hBdfl Guag s Gshu M hWah e as gut udhyG dsha yyu C ah hWu RBgh BOp Bs Hd Euyus: fiWu tar hi guC wo 5 e yy hWud Ku i su C OBg t BMM ss Bd dE hWu NBgh Wugd p EWhs Qat yh us Ve Wt W s hWu e BgyC's Pgsh Br udms Bi gt u wo 5 hgadsr Bgh ad C shBgaEu dQgashgi th igu: fiWu r yBh r gB9uth e yy Cgae suae ahug adC guMBl u a Muasi ga Kyu shgua M BOwo 5 QgBM h fiWu Qu as K yhG ad C Cus Ed BOHWu r yBh r gB9uth s ayguaCG i dCuge aGVe hW dsha yah Bd r yad duC OBg hWu Qayy BO 505): fiWu sittuss BOhWu r yBh r gB9uth tad r Bhudh ayyG yuaC hB hWu Cul uyBr Mudh BOyagEuns tayu t BMMug t ayr yadhs d TuG guE Bds agBi dC hWu e BgyC q;) U:

wa yhut W s Cul uyBr dE ad BQ8WBgu s Gshu M Kasu C Bd uyut hgBC ayGs s t Bdtur h hB u l hgath wo 5 QgBM Btuade ahug q; 4U: fiB gu Ci t us Gshu M ass Bm t ahu C t Bsh ad C r gBt ussu C e ahug l Byi Mu Vr gB9uth e yy Ku a Mu C hB l ay m Ca hu WEW ti ggudh Cuds hGV yBe r Be ug uyut hgBC ayG, ug sha t T ad C Mu MKgadu t Bdhat hBgs hB Qat yhahu wo 5 tar hi gu: fiWu r gBr BsuC s Gshu M e yy r gBl Cu a l aKyu r ahWe aG hB tar hi gu wo 5 ah hWu t Bsh BO< 200 %. n fl hBd wo 5 ad C t Bi yC Ku stayu C i r hB Mi yh m E. Eah Bd wo 5 fIGuag:

* ffi Wa s r gBr BsuC Ka hhug Gay Tu uyut hgBm se dE n o w s Gshu M q; 8U: x hW hs Ka hhug Gay Tu t BMr Bs h Bd BOuyut hgBt WuM tay t uyys VhWs t i h d Em CEu hut Wd ByBEG u QQut h l uyG guyuasus wo 5 o t uad e ahug Vud Wa dt us hWu e ahug's ayTay d hGVad C guhi gds hWu hguahuC e ahug Kat T hB hWu Btuad: fhs dd Bl ah l u Cus Ed s suh hB gul Byi h Bd , u hWu e aG e u hat Tyu Btuad at C P t ah Bd Vad C hWs s Gshu M t Bi yC Ku a s Ed P t adh shur hBe agCs a MBgu si sha da Kyu O hi gu: fiWu r gBr BsuC s Gshu M KBash s sul ugay d Bhue BghWG a Cl adh a Eus: v gsh ad C OBgu MBsh V h BKl ahus hWu duu C OBg u l r uds l u Mu MKgadus Bg si r r yu Mud m hagG t WuM tays: . ut Bd CyGV hs uasu BO Cur yBGMudh gud Cugs h r gath tay. fiWgCyGV h s Qguu QgBM KGr gBCi ths: HCC h Bday GVhWu r gBr BsuC dd Bl am h l u yut hgBCu t Bd P Ei gah Bds agu WEWyG u QQut h l u ah guCi t dE hgadsr Bgh ad C uyut hg tay gus shadt u yul uys d hWu t Bdhu l h BOyagEu e ahug l Byi Mus: fiWs s Gshu M s t Wa gath ug , uC KG yBe udugEuh ts VQat yh ahu C KG gudue aKyu sBya gBg e dC gus Bi gt us Vad C t ad Ku dsha yyu C Bd r yah OBgMs Bg tagEB s Wr s:

fiWu. e ss vu Cugay paKBgah Bg us OBg * ahug ays . t udtu ad C fiut WdByBEG cS* RHjV. e h, ugyad CVWál u r gBr BsuC uyut hgBC ayGs s t Bdtur h hB t ar hi gu 5:) hBd BO wo 5 fIW fiWs r gB9uth dl Bylus hWu Cul uyBr Mudh BO "o t uad vyBah dE fsyad Cs" hWah e Bi yC Br ugahu l a uyut hgBC ayGs s V a r gBt uss r Be ug uC KG sBya g udugEG OBg hWu s Mi yh aduBi s r gBCi th Bd BO(5 ad C u l hgath Bd BOwo 5 QgBM Btuade ahug q í 0U: fiWu r gBr BsuC dsha yyah Bd tad Ku MBi dhuC Bd a P l uCnW yys Wr Vad C e Bi yC t Bds sh BOí 0 t yi shugs Vuat W e hWr WBhBl Byha t cR$ j syad Cs BO200 dM C a Muhug: fiWu hBha y si Qat u agua t Bl ug uC KG hWu R$ syad Cs e Bi yC Ku 440W000 M^{5}Ve hWhWu udh gu dsha yyah Bd Bt t ir G dE a si Qat u agua BOar r gB1 Mah ur G 2 TM^{5}: fiWu R$ syad Cs e yy r gBl Cu uyut hg tayr Be ug hB hWu Cusay dah Bd ad C uyut hgBy Gs s t uys OBg (5 r gBCi th Bd VhWu uyut hgBt WuM tayt uys OBg wo 5 u l hgath Bd VhWu tah ayGht guat hBgs OBg Muh WadBy r gBCi th Bd ad C sur agah Bd VshBgaEu Ka hm hug usVa Muh WadBy sh BgaEu h ad TVad C BhWug dsha yyu C at t ussBg us: x hWa hBhay dt BM dE sBya g r Be ug BO250 * x ad C 50 / uOPt udh R$ MBCi yus V hWu s Gshu M t Bi yC r gBCi t u ad al ugaEu BO5) * x $_{uy}$ BOuyut hg tayr Be ug: Hh Btuade ahug [Be BO) 2W000 hBdfl WSn t uys e Wt W t Bds i Mu 4:2 * x $_{uy}$ V t Bi yC u l hgath hWu C ss Byl u C wo 5 e hW4; / uOPt udt GVG uyC dE 5:) hBdfl W wo 5: St Bd BM t ayGVa Mi t W yag Eug uyut hgBC ay Gs s [Be c) 2W000 hBdfl Wj e Bi yC gu- i gu a dBl uyVWEWyG t Bsh mOPt udh Muh WBC: fhs WBi yC Ku dBhu C hWah a s M yag Btuade ahug [Be gah u s r guh guah uC d hWu Fo Cusay dah Bd r yadh i s dE sad C Pyhgah Bd e hW r ug BC t Kat Te as WdE q í 0U: vi gh WugM MBgu VhWu tar hay t Bsh s OBg Btuade ahug r guh guah Mudh u- i r Mudh ad C [Bah dE syad C shgi th igus agu WEWyG i dt ugh a d:

fiWu udugEG ad C udl gBd Mudh ay gus uagt W t udhug cSSF wj Vd Bdr gBP h C l s Bd BOHWu %d l ugs hG BONBgh Wa n a T Bha Vj Bt ah uC d L gad C v BgTs VNBgh W n a T Bha V%d huC . hah usj Wa s r gBr BsuC n o w hut Wd ByBEG Kas uC Bd t Gt yt r gut r hah Bd BO t ag KBdah us QgBM Btuade ahug d a r gBt uss tay uC W QCgBm yGht s BOhud dE q; íU: fiWs ddBl ah l u r gBt uss Kuags s M yag h us hB t Bdm l udh Bday e ahug hguah Mudh Muh WBCs: Sssudh ayyGVhWu e ahug s s BOhuduC hWgBi EWhWu r gut r hah Bd BOC ss Byl u C dBgEad t t ag KBd cn fwj as tayt i M

tag KBdah u l a hWu i su BOWGCgah uC y Mu: (GCgByGht s BOhud dE r gus udh s a r gBM s dE s Byi h Bd OBg hWu Cut BMr Bs h Bd BO tayt i M t ag KBdah u Vay yBe m dE OBg hWu guyuasu BOwo 5 Eas hWah t ad Ku i hy, uC OBg su- i ush gah Bd Bg dCi shg ay r igr Bsus: vi gh WugMBguVhWs r gBt uss gu Eudugah us hWu y Mu OBg gur uah uC i sa EuVMa T dE h a si sha da Kyu ad C t Bshm COut h l u ar r gBat WOBg n o w: fd t BMr ag s Bd hB Bh Wug Muh WBCs hWah guyG Bd Mu MKgadu uyut hgBm C ayGs s V hWu r gBr BsuC r gBt uss tad s Ed P t adh yG guCi t u udugEG dr i h t Bsh s KG i r hB íí / :

fiWu fdsh hi hu OBg wag KBd * ada EuMudh ah %d l ugs hG BOway OBgd a Vp Bs Hd Euyus Wa s r gBr BsuC ad dd Bl ah l u ad C st ay a Kyu r gBt uss Cus Ed OBg n o w q; 6U: fiWs due r gBt uss dl Bylus a s dE yunshur uyut hgBy Ght r gut r hah Bd BO tag KBdah us: fd hWs r ugs r ut h l uVBt uade ahug cas ad uyut hgBy Ghuj s r i Mr uC hWgBi EWuyut hgBy Ght [Be guat hBgs VadC C ss Byl uC wo 5 d Bt uade ahug ad C ah MBsr Wugu s t BMK duC e hW wa $^{5+}$ ad C * E^{5+} sr ut us d ad a- i uBi s guat h Bd Mu C i M: fiWs dd Bl ah l u M dugay, ah Bd hut Wd By BEG s d Bha Kyu OBg sul ugays Ed P t adh a Cl adh a Eus Bl ug Bh Wug K Bh t Bg aK Bh t Mu h WBCs: * Bsh d Bha KyGV h uOPt udh yG uy M dah us hWu hWug MBCGdaM t ad C T duh t tWa yud Eus ass Bt ah uC e hW tag KBdah u r gut r hah Bd KG C gut hyG ad C d s hi uyut hgBt WuM tay yG t Bdl ugh dE C ss Byl uC dBgEad t tag KBd cn fwj dhB tag KBdah u M dugays: vi gh WugMBguVhWs r gBt uss s s Ed P t adh yGMBgu h Mum uOPt udh hWad dah i gay gBt TnKas uC M dugay, ah Bd hut Wd - i us Ve Wt W t ad gu- i gu Guags hB t BMr yuhu: HCC h Bday GVhWs Muh WBC tad Ku si t tuss OyyG ar r yuC at gBss a KgBa C gad Eu BOwo 5 t Bdt ud hgah Bds ad C hu Mr uga hi gus V QgBM a MK udh yul uys hB 200 l By/ wo 5 ad C QgBM a MK udh hB ag Bi d C ; 0 °wV e hWBi h dt ig gdE ad G a CC h Bday t Bsh s: pash yGVas a gus i yh BOHWu uyut m hgBt WuM t ay C ss Bt ah Bd BO Bt uad e ahug VsByl udh s agu d Bh gu- i guC hB sh Mi yah u wo 5 a Cs Bgr h Bd OBg Bt uad tag KBd Mad a Eu Mudh

fiWu Cur yBGMudh BO n o w sh BgaEu Qat yh us MaG Bt t ig Bds WBguV BQ8WBguVBg MBK yu r yah OBgMs: o ds WBgu n o w Br ugah Bds agu r Bs h Bd uC ay BdE t Bash y dus hB t ar hay, u Bd hWu g aC9a t udt G hB KBhWhWu Bt uad ad C yad C: o QQ8WBgu Qat yh us agu s hi ahuC d hWu Br ud Bt uad Ve hWhWu t ar hi gu C wo 5 Ku dE t Bdl uGuC hB sh BgaEu Qat yh us yBt ahuC Kuduah WhWu sua Ku CV si t Was say du a- i Qugs Bg Cur yuhu C B y ad C Eas gus ugl B gs: fd NBge aGV hWugu agu t i ggudhyG he B r gBM dudh wo 5 sh BgaEu Qat yh us Br ugah Bday V da Muy G . yu r dug ad C . døW hVKBhWs hi ahuC d hWu NBge uE ad . ut hBg BO hWu NBghW. ua: fiWu . yu r dug P uyCV Mada EuC KG hWu NBge uE ad udugEG t BMr ad G S- i dBgVWas Kuud udEa EuC d hWu sur agah Bd ad C gumd9uth Bd BOwo 5 as r agh BOa tag KBd tar hi gu ad C sh BgaEu cvw. j d hah l u s dt u 2; ; 8: fiWs d hah l u dl Bylus tar hi g dE duagyG Bdu M yy Bd Muhg t hBds BO wo 5 addi ayyG QgBM hWu dah i gay Eas u l hgath uC ah hWu P uyCV ad C si Ksum - i udhyG gumd9uth dE h dhB hWu %hs ga vBgMah Bd –a Cuur say du a- i Qug yBt ah uC Kuduah WhWu NBghW. ua q8V U: war hi ga suuTs hB ush a Kys Wr ag hm dugs Wr s e hW u l r ug udt uC tag KBd su- i ush gah Bd Pg Ms si t Was hWu NBghWugd p EWhs r gB9uth hB Qat yh ahu hWu Eu By BE tay sh BgaEu BO tar hi gu C wo 5: fiWs r gBt uss udh a ys i dCug EgBi dC sh BgaEu BO wo 5 d a si r ugt gh tay y- i C sh ahu Ve hWd Cur yuhu C B y ad C Eas OBg Mah Bds Bg Eu By BE t say du a- i Qugs: . hg dE udh yG suyut huC su- i ush gah Bd s hus e yy ud si gu t Bdh a dm Mudh BO wo 5 Ve hWhWu gus r Bds K yhG OBg MBd hBg dE ad C l ug Pt ah Bd gush dE e hWhWu su- i ush gah Bd t BMr ad G q6U: S- i dBg ad C war hi ga e yy e BgT hBEuh Wug Bd C Qugudh l ugs Bds BO war hi ga's hut Wd By BEG OBg t ag KBd tar hi gu ad C sh BgaEu: fiWu G e yy sha gh KG Ki yC dE a 2W000 hBdsfl G Bds WBgu r yBh r yadh ah S- i dBg's I ?gsh o dah i gay Eas r gBt uss dE Qat yhG d NBge aG: fiWu r yadh e yy gu MBl u wo 5 QgBM suae ahug ad C si r r Bgh hWu NBghWugd p EWhs r gB9uth Ve Wt W a Ms hB Ku hWu e BgyC's Pgsh Br udms Bi gt u wo 5 hgadsr Bgh ad C sh BgaEu dQgashgi th igu q; U:

fDfi 4nycrsxnysrsuly hiiniiu nrms a 1 b dvsyniini

vBg Cuhug M d dE hWu Quas K yhG BO ad G n o w r gBt uss OBg stay dE i r hB yagEu tar hi gu Qat yhG Vhut Wd Bmut Bd BM t assuss Mudh cfiS Hj r ya Gs t gi t ay gByu: . r ah ay Bg ut Bd BM t t Bds Cugah Bds Ma G y M h hWu stay a K yhG BO t ugh a d hut Wd By BE us: vBg uyut hgBt WuM t ay n o w t uyy VhWu h Bha y t Bsh t ad Ku KgBT ud CBe d dhB OBi g sut hBgs @u- i r Mudh t Bsh ad C r Be ug t Bsh OBg t ar m hi gu ad C guyuasu BOwo 5 ad C S n Vgusr ut h l uyG: (Be ul ug VhWu t Bdhg Ki h Bds BOhWu t ar hi gu r gBt uss VKBhWOBg u- i r Mudh ad C Br ugah Bd Vagu ay MBsh du Ey E. Kyu t BMr ag u C e hWhWu t Bsh s OBg Sn: fiWs su t h Bd e yy C st iss hWu

Ma d tBshs assBt ahuC hB wo$_5$ tar hi gu i s dE hWtsu WGKg C Sn rgBtussus d hugMs BOBrugah dE tBdC h Bds adC udugEG gu- i guMudhs q; ; U

fDfi fi UMu ynoo

fiWu zR* Sn tuyy dl Byl us he B hGr us BOtuyysV dt Bgr BgahuC dhB hWu wo$_5$ gut BlugG tuyy adC hWu ayTay guEudugah Bd tuyy: z BhWtuyys agu sad Cm e tWuC Kuhe uud a zR* adC a wS* : wS* s agu r ByGMug t MuMKgadus tBdha d dE du Eah l u O dt h Bday EgBi r s isuC hB ahhgath tah Bds Ve Wyu zR* s agu t BMr BsuC BOhe B hGr us BO Bdm1t WadEu MuMKgadus Va wS* adC ad HS* shat TuC hBEuhWugVhB r gul udh Bd yuaTaEu: HS* s agu MuMm Kgadus e hWP 1uC r Bs h l uyG t WagEuC t WuM tay EgBi r s tBdduthuC hB hWu Ma d r ByGMug t Wa ds BOhWu MuMKgadu q; ; U

Hd adayGs s e as t BdCi thuC Bd hWu hBhay Brugah Bday adC u- i r Mudh tBsh BOz* RSn tuyyhWah gut Blugs wo$_5$ QgBM K tagKBdahu sByi h Bds: q200U H 20 nshat T tuyy z* RSn i d he as i suCVe hWa sha dyuss shuuy c. % j uyut m hgBCu as hWu adBCuV r yah di MmnBahuC h had i M cRhflfi j tah WBCuV t BMMug t ayn EgaCu z* RVadC wS* : fiWs i d he as Br ugah uC aha ti ggudh Cuds hG BO; 8 HflM^5 adC a OnuC [Be gah u BO2:5 pfl Md Vgus i yh dE d k0 / wo$_5$ gut Blug QgBM K tagKBdahu sByi h Bds: fiWu sGshuM e as Cus EduC hB hguah k00 Muhgt hBdsflW BO wo$_5$ uM ss BdVe Wt W s u- i l ayudh hB hWu aMBi dh uM hhuC KG a) 00 * x t Bayn EguC r Be ug r yadh Hssi M dE a i d h t Bsh OBg uyut hg t hG ah %. J 0:25 Va M d Mi M t Bsh BO%. J 260 flhBd wo$_5$ e as at Wul uC: fiWu t Bsh BOuyut hg t hG att Bi dhs OBg ar r gB1 MahuyG 80 / BOhWu hBhay t Bsh iVe Wyu hWu t Bsh BOMuMKgadus att Bi dhs OBg k0 / BOhWu hBhay t Bsh fiB stayu i r hWu r gBt uss V he as assi MuC hWah OhWu uyut hg t r Be ug r g t u s guCi t uC hB %. J 0:08 flTx WHhWu MuMKgadu t Bshs agu guCi t uC KG 2fl20 VadC hWu ti ggudh Cuds hG s dt guasuC hB ; 0 / VhWu M d Mi M t Bsh t Bi yC Ku guCi t uC hB ar r gB1 MahuyG %. J í 0Ve Wt W s t BMr uh hl u e hW hWu t Bdl udh Bdaya M du t WuM tay aKs Bgr h Bd r gBt uss: fiWu yOnh Mu BOhWu MuMKgadus tad ays B Ku u1 hud CuC hB guCi t u hWu hBhay t Bsh O ghWug c4 Guags OBg hWu Kasu tasuj: H EgBi r Was gur BghuC a MuhWBC OBg tar hi gdE wo$_5$ QgBM K tagKBdahu sByi h Bd i s dE. NuBsur ha z R* MuMKgadu e hW a hWt Tduss BO0:5 dM: fiWs MuhWBC tad guEudugah u hWu tar hi guC wo$_5$ ah hWu t Bsh BO%. J k6:0í flhBd wo$_5$ VKasuC Bd 5050 r g tus: n i g dE Br ugah Bd VhWu sGshuM t Bdsi Mus udugEG as yBe as 40 TDflMBy wo$_5$ adC Was a ti ggudh uOPt udt G BO; 2:5 / q202U

fh s Mr Bghadh hB dBhu hWah hWu wo$_5$ tad Ku uas yG hgar r uC d hWu MuMKgadu shat T BOz* RSn Vt ai s dE a “WBh sr Bh” hWah MaG CaMaEu hWu MuMKgadu si gOat u adC guCi t u hs yOusr ad: fiB aCCguss hWs r gBKyuMVa WEWngussi guz* RSn shat T e as Cul uyBr uC hB uy M dah u wo$_5$ Eas Ki KKyus Ci g dE hWu n o wr gBt uss q62U z G dt guas dE hWu r gussi gu QgBM 2:4 ahM hB 8 ahMVhWu uyut hgBt WuM tay udugEG e as guCi t uC QgBM) í 2 TDflMBy wo$_5$ hB kkk TDflMBy nwo$_5$: fiWs WEWngussi gu shat T r gul udhuC hWu Bt ti ggudt u BO “WBh sr Bhs” adC guCi t uC udugEG t Bdsi Mr h Bd Ci g dE hWu u1 r ug Mudhay r gBt uss: fiWu r ugOBgMadt u BOhWu z R* Sn nKasuC d s h i M dugay, ah Bd MuhWBC s ays B WdCuguC KG dBgEad t OBi y dE d hWu ayTay dur (gadEu cr (≥; j e Wtd i s dE guay Bt uade ahug as OnuC: (Be ul ugV h s Kuy ul uC hWah M dugay stay dE e yydBh Bt ti g d hWu at C t t Wadduys Ci u hB hWu gy Be r (cr (≤) j: H gur Bgh si EEushs hWah at C s hWu MBsh uOnthl u t WB tu OBg guMBl dE stayu QgBM hWu MuMKgadu Vsi gr ass dE s r agE dE o$_5$ adC wo$_5$ q205U fiB Br h M, u z* Sn r ugOBgMadt u V h s aCl suC hB Cut guasu hWu gus shadt us BOhWu HS* adC wS* Vas e uyy as t guah u hWddug t Wadduys OBg hWu at CV Kasu V adC OnuC t BMr ag hMudhs q20kU Rug OBgMadt u hga CuBOO ti gl us tad Ku i suC OBg z* RSn hB Ma Tu t BMr gu Wuds l u t BMr ag s Bds Kuhe uud C OOngudhz* Sn Br ugah Bds adC s GshuMs: fh t ad ays B Wuyr d t Bsh Br h M, ah Bd Oa t Bsh MBCuy s r gBl CuC: fiWu r ugOBgMadt u hga CuBOO ti gl u sWBe s hWah hWu Cul uyBr Mudh BO WEWnugOBgMadt u K r Byag MuMKgadus tad MrgBl u hWu Blugay r ugOBgMadt u BOz* Sn hB a MBCugah u CuEguu Kut ai su Mi yh r yu t BMr Bdudhs EBl ugd hWu r ugOBgMadt u BOa z* Sn r gBm tuss: vBg z* RSn VWEWug hu Mr ugah i gu r gBt uss us: vBg dsh adt uVhWu t BMMug t ay z* R t addBh e hWshadC hu Mr ugah i gus WEWug hWad) 0–80 °w OBg a yBdE Ci gah Bd: * BguBl ugVwo$_5$ sByi K yhG Cut guasus ah WEWug hu Mr ugah i gus ci hB 200 °wj: fiWs Muads hWah Br ugah dE ah WEWhu Mr ugah i gu s dBh Guh r gath tay.

fDfi fi MbMtMO hr, bouun, lhrn, Mb ynoi

vgBM ad ut BdBM t r B dh BOl ue Vwo$_5$ tar hi gu s Bdy G l aKyu OhWu udugEG t Bdsi Mr h Bd BOhWu tar hi gu s < 88 TDflMBy wo$_5$ Ve Wuguas Vuyut m hgBt WuM tay r gBt ussus BOhud Wal u udugEG t Bdsi Mr h Bd Eguah ughWad k00 TDflMBy wo$_5$ q í) U fd hugMs BOudugEG t Bdsi Mr h Bd VaMBdE hWu uyut hgBm t WuM tay no ws GshuMs VS(p s MBgu t Bshm nOnth l u ar r gBat WOBg stayu i r Cus Ed qkí U: vBgu1a Mr yuVz R* Sn t Bdsi Mus ar r gB1 MahuyG 2) 00 Tx Wfl hBd wo$_5$ BOuyut hg t udugEGVe Wyu SwS i sus agBi dC 50V000 Tx WflhBd wo$_5$: wynMuC ahuC Sw t Bdsi Mus aKBi h 8; ; Tx WflhBd wo$_5$ Ve Wuguas S(p [Be tuyy gu- i gus gBi EWyG 880 Tx WflhBd wo$_5$: x Wyu i s dE at C PuC s Mi yahuC suae ahug ahr (Z): í Va z R* Sn tuyy t Bdsi MuC Z 244 TDflMBy wo$_5$ cZ ; 00 Tx WflhBd j Ve Wt W s ar r gB1 MahuyG 2:4 h Mus WEWug hWad hWah BOhWu S(p [Be tuyy q í 8U: o hWug hWad udugEG t Bdsi Mr h Bd VB1GEud ul Byi h Bd gum ath Bds ahz R* Sn adC Sw S gu- i gu t Bshy G fgo$_5$ t ahay Gshs e Wt WWdCug hWu r Bhudhay OBg yagEumst ayu Cur yBGMudh e Wtd t BMr aguC e hWuyut hgBy Gs s OBg WGCgBEud r gBCi th Bd: fd t Bdhgash VS(p s GshuM i hy, us Bt uade ahug as uyut hgBy Ghu dshuaC BOt WuM tay nKasuC uyut hgBy Ghus: vBg WEWyG uOPt udh sGshuM OBg yagEumst ayu Cur yBGMudh V rug BC t t yuad dE adC sBOhud dE BO Bt uade ahug KuOBgu d9uth dE dhB S(p [Be tuyy s rug- i s hu OBg al B C dE stayu adC * Eco (j$_5$ adC waco (j$_5$ Cur Bs h Bd ah uyut hgBCus:

wBMr aguC hB BhWug uyut hgBt WuM t ays GshuMs VhWu gut udhyG dhgBCi t uC wynMuC ahuC uyut hgBt WuM tay no ws GshuM t Bshs %. J 48 flhBd wo$_5$ adC s t Bds CuguC t Wuar ush a MBdE ayy Mudh Bdu C uyut hgBt WuM tay s GshuMs sB Qag q5; U fiWs t Bsh CBus dBh dt yi Cu hWu uyut hgBCu gur yat u Mudh t Bsh hWah ays B hud Cs hB Ku yBe ug s dt u BdyG he B uyut hgBCus agu dl Byl uC e Wt WCuMad Cs MBgu Qgu- i udh gur yat u Mudh hWad hWu dshayuC z fl HEwy uyut hgBCus: o l ugayy ush Mah uC t Bsh OBg si t Wuyut hgBt WuM tays GshuM s %. J 200 flhBd wo$_5$: z GaCC dE hWu t Bsh BOBhWug sGshuMs si t Was Bt uade ahug r i Mr dEV dha Tu Pyhgah Bd Vad C wo$_5$ sur agah Bd VhWu hBhay r gBt uss t Bsh t Bi yC guat Wi r hB %. J 5V000 flhBd wo$_5$ q í 8U: vBg Cur yBGMudh BOuyut hgBt WuM tay no w s GshuMs ah yagEug stayu VOh i gu uOBgh s agu gu- i guC hB guCi t ur i Mr dE ad C CuEass dE t Bshs:

fDfi fi Oq b ynoi

H r guy M dag G fiSH e as r ugOBgMuC hB CuhugM du hWu Onas K yhG BO stay dE i r BO(v* ws nKasuC no ws GshuM hB yagEu no w Oat yhG: S sh Mah uC tar hay ad C Br ugah dE t Bsh s OBg a C gut h Btuad tar hi gu (v* w r yadh hWah tar hi gus ; 60V000 HBdflGuag BOwo$_5$ e as %. J ; V484 q68U: wBsh ada yGs s gul uayuC hWah ti ggudh no ws GshuM s 28 h Mus MBgu u1 r uds l u hWad n Hw Kud t WMag Ts Ci uhB hWu l ugG yBe wo$_5$ guMBl ay gah us: * a d guas Bd OBg yBe [i 1 gah u BOwo$_5$ s hWu yBe t Bdt udhgah Bds BOwo$_5$ d Btuade ahug: vBg hWs shi CGVs Gdh Wuht suae ahug e hWa wo$_5$ t Bdt udhgah Bd BO220 r r M e as isuCVe Wt W s s Ed P t adh yG yBe ug hWad hWu ah MBsr Wug t wo$_5$ t Bdt udm hgah Bd BO ar r gB1 MahuyG) 28 r r M gut BgCuC d 502; : vyi 1 tad Ku dt guasuC KG Br h M, dE C Ongudh l ag aKyus i t Was [Be gah u Vhu Mr ugam hi guVMuMKgadu hWt Tduss VWBe ul ug hWusu Br h Bds agu d Bh si OPt udh hB Ma Tu a t Bshm nOnth l u no w s GshuM: fiB dt guasu wo$_5$ [i 1V Bdu t Bshm uOnth l u Br h Bd s hB guCi t u hWu r (BO Btuade ahug Kut ai su guCi t dE r (e yy guyuasu Easu Bi s wo$_5$ adC dt guasu wo$_5$ [i 1: fd CB dE s BVhWu MuMKgadu t Bshe yy dt guasu he t uOBgyBe ug dE r (hB Bdu e WByu di MKug hWah e yy at Bi dh OBg hWu u1 hga t Bsh BOyBt ayyG hguah dE Bt uade ahug r (: Nul ughWuyuss Vul ud aOnug aCC dE aCC h Bday MuMKgadu t Bsh V O Bt uadm e ahug r (tad Ku yBe uguC QgBM 6 hB 4VhWu t Bsh BOhWu s GshuM tad Ku guCi t uC QgBM %. J ; V484 hB %. J 5; 0 flhBd wo$_5$ l ayi u gusr ut hl uyG: fd hWs t Bsh gad Eu cZ %. J k00 j VhWs no w hut WdByBEG MaG Kut BMu t BMr uh hl u e hWshahumBOhWumaghn Hw s GshuM q68U

fDfDfi I , , lnhEnixKhin, u lr mvhd5hnhsr hddvshycni

wBds Cug dE aCC h l usnKasuC no w r gBt ussus V M dugay, ah Bd BO Bt uade ahug is dE shuuy sya E e BgTuC ah yBe udugEG t Bdsi Mr h Bd BO25í Tx WflhBd wo$_5$ e Wt We as t ayti yahuC att BgC dE hB hWu Mass BO[i u EasV adC hWu hBhay sGshuM t Bsh t BM dE QgBM r i Mr sV t gi s WugV M 1ug adC sur agah Bg e as ush Mah uC hB Ku %. J 20:) flhBd wo$_5$ q) 2U: wi n dCi sh g ay e ashu adC Bt uade ahug as sByl udh e as i suC d adBhWug no w r gBt uss: (Be ul ugVhWu t Bsh r ug hBd BOt ar hi guC wo$_5$ e as dBh tay i yahuC: Nul ugm hWuyuss V h e as si EEushuC hWah a tuMudh Madi Oat hi g dE r yadh Bg r ar ug

M yyhWahuM hs a yagEu aMBi dh BOwo$_5$ adC i sus wa wo$_k$ as a gae Mahug ay r gusudh d tyBsu l t d hG hB hWu Btuad e Bi yC Ku l ugG KuduPt ay OBg hWs hut WdByBEG hB Ku stayuC i r d MBguut BdBM t adC ut BnGgudCyGe aG q) 5U: fiB O gh Wug guCi t u hWu t Bsh BOn o w stayuC i r Cus EdsVhWuG sWBi yC Ku dhuEgahuC e hWBdsWBgu Cusaydah Bd r yadhs hB haTu aCl adhaEu BOHWu dshayuC e ahugnWadCydE Oat yhus: fiWu t ar hi guC wo$_5$ tad Ku d9ut huC C gut hyG QBM r yahOBgMs dhB si Knsi gOatu EuByBE t shgi t hi gus OBg yBdE hugM su- i ushgah Bd Bg i suC as a OuC shBt T OBg O uys Bg OBg t BMMBC hGadC sr ut ayhG t WuM t ays r gBCi t h Bd:

fiWu Mag h Mu hgadsr Bgh t Bsh s adBhWug Oat hBg d M dugay, ah Bd a r r gBat W fh Was Kuud ush MahuC hWah h M EWh haTu 200 sWr s GuagyG hB at Wul u a duh tagKBd guMBl ay BO ar r gB1 MahuyG 2L h BOwo$_5$Ve hW ad udugEG t Bdsi Mr h Bd BO; ; :4 * DfIhBd q8í U: F ut udhyGVgusuagt Wugs aCl Bm tahuC a sue aEurGuyl uguC Btuad ayTayd hG udWadt uMudh c. n o HSj ar r gBat WhB guCi t u hgadsr Bgh t Bsh s q20) U: Hr r gB1 MahuyG 2V000 TM^k BO e ashue ahug csue aEuj s Eudugah uC ad C C st WagEuC e BgyCe Cu addi ayyG: . ue aEu t Bdha ds WEWt Bdt udhgah Bd BOBgEad t at Cs e Wt WguCi t us hWu r(BOsue aEu: fiWugu OBguV. n o HS ar r gBat Wt ad Ku i suC hB hgadsr Bgh shgBdE ayTays Val B C dE a s Ed P t adh aMBi dh BOsut BdCagGr gut r hah Bd c :u: Vwa wo$_k$jVhWah t ad O gh Wug guCi t u hWu Blugayy t Bsh BOn o w r gBt uss q20) U: fiWu r(BOsuae ahug s hGr tayyG dBh t BdCi t l u hB C ssByl dE Byl du ad C wa wo$_k$VKi h hWu g C ssByi h Bd t ad Ku Oat yhahuC KG hWu. n o HS ar r gBat W fiWs r gBt uss dt guasus hWu ayTayd hG BOhWu e ahugVe Wt Wt ad Ku tagg uC BOQWBgu KGg l ugr yi Mus ad C Bt uad t i ggudhs: fiWugu OBguVBt uad ayTayd hG udWadt uMudh ad C tagKBd C B1 Cu guMBl ay t ad Ku Mr yum MudhuC Bd a yagEu stayu:

* h Eah dE MuMKgadu OBi ydE ad C uyut hgBCu r B s Bd dE d C gut h Btuad t ar hi gu cn o wj hut WdByBE us dl Byl us sul ugay shgahuE us: vBg MuMKgadu OBi ydEVr gurhguah Mudh BOsuae ahug i s dE P yhgah Bd Vt WuM t ay hguah MudhVad C %$ yEWh s ussudhayVayBdE e hWa dh mOBi ydE MuMKgadus udWadt uC hWgBi EW si gOatu MBC P t ah Bd ad C WGCgBr Wyt r gBr ugh us: o r ugah Bday shgahuE us sit W as Br h M, dE [Be gah uV Kat Te as WdEV t WuM t ayt yuad dEVad C t BdhgBy dE K BOBi ydE e hWK Bt Cus ad C t Bah dEs aysB r yaG t gi t ay gByus q) U: fiB t BMKah uyut hgBCu r B s Bd dEV suyut hdE gus shadh Bg ayyBGuC Mahug aysV si gOatu MBC P t ah Bd e hW r gBhut hl u t Bah dEs ad C t ahayGshyaGugs Vad C Br ugah Bdayshgahu E us sit Was r Bhudhay t BdhgByVr ug BC t guEudugah Bd Vad C r gBr ug uyut hgByGhu [Be agu uOOt hl u q4U: HCC h Bday GVuyut hgByGhu Mada EuMudh hWgBi EW guEi yag r i g P t ah Bd ad C aCC h lus tad r gul udh t BdhaM dadhs QBM a OOt hdE uyut hgBCus: fMr yuMudh dE hWusu ar r gBat Wus Mr gBl us hWu uOPt udt G ad C yBdEul hG BO n o w sGshuMs Vr gBMBh dE si sha da Kyu tagKBd t ar hi gu QBM Bt uad e ahug q) V4U:

, p r gy euikdgt f 2l(22t I nr ut h I %r l2 xt gcg; 12d

n gut h Hg war hi gu cn Hwj s ays B ah hgat hdE dt guasuC ah hudh Bd ad C P dadt ay dl ush MudhQBM dBhaKyu P Ei gus yTu z yyL ahus ad C S yBd * i sT q204U: wBMr aguC hB n HwV n o w s ad ul ud yuss u1 r yBguC hugg hBgG: (Be ul ugV S- i aht V war hi ga V ad C BhWug t BMr ad us agu e BgT dE hB CuMBdsh gah u hWu t Bdt ur h's Oua s K yhG e hW si r r Bgh QBM hWu wWid] i t Tug KugE fd hah l uVL ahus vBi dCah Bd VB yad C Eas t BMr ad us Vad C hWu HCl adt uC F usuagt WRgB9ut hs HEudt GnSdugEG cHF RHn8j: fd hWs sut h Bd Va t BMr ag s Bd Kuhe uud n Hw ad C n o we yyKu r gusudhuC d hugMs BOr gBt uss Cus Ed ad C udugEG CuMad CV t ar hi gu t Bsh VyadC i su ad C yBt ah Bd V st aym aK yhGVad C r Bhudhay OBg dhuds P t ah Bd:

Dfi fi Uvsynii , nilgr hr, nr nvge , nu hr,

wBdl udh Bd ayn Hw hut WdByBE us Wal u hga C h Bd ayG guy uC Bd hWugMay aM dumKasuC st gi KK dE MuhWBCs hGr tayyG i suC hB sur agah u wo$_5$ QBM dah i gay Eas ad C WGCgBEud q208U: fiWs MuhWBC uMr yBGs a t WuM t aye uh r gBt uss V e Wugu KG y- i C s BgKudhs t ar hi gu wo$_5$ ad C hWid guyuasu h hWgBi EW a huMr ugah i gu c200 °w–240 °wj Bg r gussi gu ci r hB 20 TRaj se dE cfi. Bg R. j r gBt uss: fd n Hw r yBhad C t BMMug t ayr yadhs Va Cs Bgr h l us By Cs Bg Kas t a- i uBi s sByi h Bds agu MBshyG i suC hB t ar hi gu wo$_5$ QBM ah MBm sr Wugu hWah gu- i gus guyah l uyG s Mayyug OBhr g dh ad C t Bi yC Ku r Be ugu C KG gudue aKyu udugEG si t W as sByagV e dCV ad C EuBhWugMay sBi gt us q5) Vk5V)4U: x Wyu hWs MuhWBC Was Kuud hush uC Bd a yagEu stayu OBg wo$_5$ t ar hi gu QBM dCi shg ayr Be ug r yadhs ad C s a guy aKyu hut WdByBEGV h Was sBMu e ua Tdussus hWah guMa d as a t Wayyud E dE has T OBg t BMMug t ay ar r yt ah Bd q20í V206U: v gshyGVhWu aM dumst gi KK dE MuhWBC s e CuyG i suC OBgr B dh s Bi gt u tagKBd t ar hi guVe Wt Wsh yy agu ahhg Ki huC hB 80 / BOa ddi ay wo$_5$ uM ss Bds: war hi g dE tagKBd uM ss Bds QBM r B dh s Bi gt us dl Byl us ad ush MahuC hWugMay udugEG gu- i guMudh BOaKBi hk:5–):0 L Df l hBd BOwo$_5$ t ar hi guC: fiWs su- i l ayudh hB 6; –225 M yyBd fiD BOa ddi ay udugEG t Bdsi Mr h Bd Ve Wt Wat t Bi dhs OBg aKBi h 2k–2í / BOhWu e BgyC's udugEG t Bdsi Mr h Bd q20; V220U: (Be ul ugVi s dE hWugMBt WuM t aymKasuC t ar hi gu d WEWgG C yi huC wo$_5$ t Bdt udhgah Bds c0:0) / wo$_5$j gu- i gus MBgu udugEG e hWa hBhay):6–20:5 L D BOhWugMay udugEG r ug hBd BOwo$_5$ t ar hi guCVe Wt W s dBhr gat h t ayyG Oua s Kyu q222U: S dugEG gu- i guMudh s O gh Wug dt guasuC OBg sByl udh n Hw hut WdByBEG e Wt W s u- i l ayudh hB u hWug 6:62 L D dah i gay Eas Bg 4:54 L D dah i gay Eas t Bi r yuC e hWk88 Tx W BOuyut hg t hG: n Hw t ad Ku t Bds CugC as a "guP dugG OBg hWu sTG' e Wud h t BMus hB udugEG: fd hWu %d huC. h ahus VguP dug us t Bdsi Mu ar r gB1 MahuyG aKBi h660 fix WBOudugEG r ug Guag: Hssi M dE hWu saMu a MBi dh BOudugEG s i hy, uC OBg n Hw ad C hWah uat Wn Hw Oat yhG gu- i gus aKBi hk00 * x BO t Bds shud hudugEG hB t ar hi gu 2 * hwo$_5$flGuagVhWu saMu- i adh hG BOudugEG t Bi yC Ku i suC hB t ar hi gu kí 0 * hwo$_5$flGuag: fiWus u P Ei gus CuMBdshgah u hWu r Bss K yhG ad C C OPt i yhG BOCur yBG dE n Hw Bd ad dCi shg ay stayu QBM ad udugEG r ugs r ut h l u q225U:

fiWu udugEG uOPt udt us BOHWugMBCGdaM t nGg l ud t ar hi gu sGshuMs agu si Kr agVhGr t ayyG gad E dE QBM 20 hB 24 / Ci u hB dWugudhy M hah Bds e hWd hWu sGshuM si t W as VWEW guEudugah Bd t Bsh VCu Ega Cah Bd BOa Cm sBgKudhs ah WEWug huMr ugah i gus as e uyy as r BBg gut Gt ya K yhG BOa CsBgm Kudh . ut Bd CyGVt Bds Cug dE L KKs Oguu udugEGVguEudugah Bd r gBt uss hB sr Bdh a du Bi syG guyuasu wo$_5$ OByyBe uC KG hWu t ar hi gu r gBt uss gu- i gus udhgBr t t Bdhg Ki h Bd KG dt guas dE huMr ugah i gu hB t BMr uds ahu udhWayr t t Bdhg Ki h Bd: (EWug huMr ugah i gu OBg wo$_5$ guyuasu t Bi yC ays B yua C hB sBgKudh Cu Ega Cah Bd Vgus i yh dE d syBe ug wo$_5$ aCs Bgr h Bd gah us ad C yBe wo$_5$ t ar hi gu uOPt udt G q22kU: (Be ul ugV WEWmEgaCu c; 00 °wj Wuah Cu Mad C BOa- i u Bi s sByi h Bdm Kasu C n Hw t Bi yC y M h hWu Br h Bds OBg Wuah sBi gt u ad C dt guasu hWu t Bsh q24U: fiWs st udag B s u1 r ut huC hB gu- i gu MBgu udugEG hB t ar hi gu ad C guyuasu wo$_5$ QBM hWusu C yi huC sBi gt us ad C MaG Mr uCu hWu t Bdh di uC i su BOe uh st gi KK dE d wo$_5$ t ar hi gu sGshuMs: vi gh Wug MBguVhWu e Cusr gua C i su BOhWs MuhWBC Was Kuud Mr uCuC KG WEWmhuMr ugah i guflr gussi gu hWah gu- i gu s Ed P t adh t Bsh s hB sur agah u wo$_5$ Vas e uyy as udl gBd Mudh ay ssi us assBt ahuC e hW hWu i su BOt BggBs l u aM du Cug l ah l us as wo$_5$ sBgKudhs q22) U:

vBg n o wV uyut hgBt WuM t ayyGmMuC ahuC t agKBd t ar hi gu cS* wwj Was Kuud u1 huds l uyG shi C uC as a l aKyu ayhugdah l u hB aM dumst gi KK dE t agKBd t ar hi gu sGshuMs q222U: fiWu r g MagG C sh d t h Bd Kuhe uud S* ww ad C aM dumst gi KK dE r gBt uss us s hWah hWu udh gu t ar hi gu ad C guyuasu r gBt uss us agu guEi yahuC KG ar r yG dE a K as Bg r Bhudhay hB ad uyut hgBm t WuM t ay Cul t uV dshuaC BOa fi. ffR. se dE: %s dE hWu S n t Bdt ur hV d hugMs BOudugEG i hy, ah Bd Vn o w s t Bds CuguC Oal Bga Kyu Blug n Hwe hWa hBhay i saEu BO2:k Tx WfITE c2V2í; Tx WfIhBdj BOwo$_5$ as t BMr aguC hB 2:4) hB 5:) 4 Tx WfITE c2Vk; 8:í hB 5V555:24 Tx WfIhBdj d hWu t asu BOn Hw: fCuayyGVS* ww Cul t us t ad t BMK du e hWgudue aKyu udugEG hB Eudugahu r Be ug OBg wo$_5$ t ar hi gu: fiWu MBCi yag hG ad C r Bgha K yhG Oua hi gus BOS wws Oat yhahu C gut h a g t ar hi gu QBM ad G yBt ah Bd V hWugu KG u OOt hl u yG Kayadt dE hWu uM ss Bds ad C aCl adt dE hWu t ai su BOt agKBd dui hgay hG:

Dfi fi b s imndhr, Hinhr, gnsgvhdclyhoo yhdma

n usr hur Bssuss dE hWu t ar aK yhG hB t ar hi gu WEWa MBi dh s BOt agKBd V n Hw hut WdByBEG gu Ma ds r gBWK hl uyGu1 r uds l u ad C Was Guh hB Muuhh Wu dut ussagG uOPt udt G sh ad Cag Cs gu- i guC hB hat Tyu hWu EyBKay t agKBd t ar hi gu t Wayyud Eu: Ragh t i yagyGVah yBe ah MBs r Wug t wo$_5$ t Bdt udhgah Bds BOa r r gB1 MahuyG) 50 r r MVn Hw Mr y t ah Bd e Bi yC Ku MBgu t Wayyud E dE ad C u1 r uds l u e hWWEWush ush MahuC t Bsh hB Ku Kuhe uud Z %. J 400 hB 800 flhBd wo$_5$ e Wt Wy M h s hs r gul ayudh Mr yuMudhah Bd q224U: HhhWusu l ugG yBe wo$_5$ t Bdt udhgah Bds Vs Byl udhs Bg s BgKudhs e hWshgBdE K dC dE

taraKyhusagugu-i guC: Hswo$_5$KdCdEtaraKyhGsQashugehWshgBdEKasuVhWugu0BguVOBgaKsBgrhBdVatWBsudsByludhsWBiyCKuashgBdEKasu: fiWsKdCdECuMadCsatWuMtaysWOhrgBtussVeWtWdhigdgu-igusMBgu udugEG: . MyagyGVOBgaCsBgrhBdVlhB sahigahu sByCsBgKudhVaCgl dE0Bgtu sduuCuC0BguEudugahBdadCe hWBihWahCgl dE0Bgtu MBgu udugEG sduuCuChBguyuasuhWuwo$_5$QgBMhWusBgKudh fdCBdEsBVyagEug sigQatu agua adC uOPtudh sByC Bgy-i C sBgKudhe BiyC Kugu-i guCe WtWshWusutBdCyagEushQathBgaOhuguyuthgthG dhWutarhaytBsh BOan Hwryadh q228U: wagKBd SdEduugdE's sBCiM WGCgB1 CumKasuC BrugahdE ryadhryatus tBshse hWd hWugadEu%n%.J;)–5k5flhBd wo$_5$q22íU: fiWutarhaytBsh BOtBdshgithdE hWuwyMue BgTs' (de y nHwsGshuMVe WtWtarhigus ;00 hBd wo$_5$flGuage as%.J k–) MyyBde WtWshWu yagEush d[iudtug BOhWu yuluy,uC tarhigu rgtu BO%.J 400–800 flhBd BOwo$_5$q225U:

fiBCahuVMBshrgBMdudhno warrgBatWusisuuyuthgBtWuMtayeahugmsryhhdEhBraghhBd suaeahug dhBatCtadCKastshguaMs adChWidtarhigdE BOwo$_5$QgBMhWuatCtshguaM qí8V60V62UcvE:)j:vBgshadCmayBdu SnnKasuCnowryadhWushMahuCtBsh s2V6í0hB5V40%.JflTEwo$_5$eWtWs5hMus MBgu hWadwyMue BgTstBshBOnHw q5)U: nowtBsh tBiyCKuguCituChB400%.JflhBd wo$_5$OaCusaydahBdryadhsyBtahuCdtyBsult dhGKGihy, dE dQashgithiguVKihVhWahe yyguCituhWuwo$_5$tarhigutarat hGhByusshWad 200ThBdflGuageBOwo$_5$qí5U: FutudhgusuagtWWasCuMBdshgahuCisuBOP1uCKuCBOsBCiMtagKBdahutarsiyusQBgnowrigrBsu: SshMahuCtBshBOhWuCusEduCnowsGshuMeas%.J6Výí:k)flhBd wo$_5$eWtWsdBhutBdBMtayyGtBMruhhlutBMraguChBhWunHwdCishgayhagEuhtBshBO400hB800%.JflhBd q224U:

fdhugMsBOEuBEgarWtayyBtayhGVnHwsdBhyMhuChByBtahBdsehWyagEuVshahBdagGwo$_5$sBigtus: fdrgdtryuVhtadKuarryuCadGeWuguVayhWBiEWheBiyCKu CuayhBWaluKBhWadudugEGsBigtuadCawo$_5$shBgaEushuduagKG: fiWsWassulugayaCladhaEus3sMayynatayu dCishgustadtBdhdiuhBBrugahue hWBihWuduuC0BgrgBtussMBCPtahBdsVwo$_5$mrgBCitdEQatyhushWahaguyBtahuCQagaeaGCBdBhgu-igu1huds luwo$_5$hgadsrBgh dQashgithiguVnHwQatyhustad KutBmyBtahuCehWgudueaKyudugEGEudugahBdQatyhushBguCitu hgadsMss BdyBssusVadCflBgehWwo$_5$shBgaEuQatyhushB MdM,uhgadsrBgh tBshsadCdQashgithigu: fiWuyBtahBd sWBiyCaysB tBds Cug hWuyadCihy,uCVrugMuaKyhGBOyadCVduagKGagadCdBsurByyihBdVadChWuCstWagEudhByBtayeahuge aGs: xWuguasVCusEddEa nowsGshuMtBiyCKuutBdBMtayadCsMayyug ds,uhWad anHwsGshuMsdtu hduuCshBrgBtuss MitWyuss [iClByiMuVeWyunowBrugahdEryadhstBiyCKudshayyuC BQ8WBgu adCaKBluwo$_5$gusugIBgsidCugHWusua[BBghWahe BiyCdBhgu-igulayiaKyuyadCsratuaseuyyasguCituhWutBshBOwo$_5$hgadsrBghahBd:

DfifiAyhohKldmahr, lrmril yhrhsr imhmnglni

fiWurgMagGdCishgayCuluyBrugsBOnHwhBCaGagu wagKBd SdEmduugdEcwadaCajadCwyMue BgTsc.eh,ugyadCj:HttBgCdEhBhWufSHVas BO5055 hWugu agu 2; BrugahBdaynHwryadhseBgyCeCu ehWHWurBhudhayhB tarhigu ir hB 0:02 * hwo$_5$flGuag q225V226U: wagKBd SdEmduugdE shWuPgshtBMMugtayudhhGhBrigsiusByludhnHwhutWdByBEG: fiWuGisuarBhassiMWGCgB1 CusByludhnKasuCarrgBatWhBhWugnHwhutWdByBEGtBiryuCehWa tayt iMtaisht gutBlugGyBBr: wagKBd SdmEduugdEstiggudhyGKiyCdEhWuyagEushnHwQatyhGVtayyuC ". fiFHmfio."VehWatarhigdEtarathGBOWayOaMyyBdBOwo$_5$addiayyGadCrBhudhayOBgstayumrhB2MyyBd: fhsu1ruthuChWahWsryadhe yyKuBrugahBdayKGMCn5054 d fiu1asV%H: wyMue BgTs stiggudhyGtBdmshgithdEhWuyagEushnHwadCshBgaEuryadhc* aMMBhWryadhjd (uyymsWuCVeWtWe yyKu Cus EduChB tarhigu ir hB k8V000 hBds BOwo$_5$addiayyGadCsryadduChBKuBrugahBdayKGhWuMCCyuBO5054 q55U:

vBgnowVhWugu agu dB dCishgayryadh BrugahdE GuhVWBeulugVwarhigaVWasyaidtWuChWuPgshnowrybhryadhBOOHWutBashBONuerBghzuatWVwH d 5052 eWtWstaraKyuBOtarhigdE 200 hBds BOwo$_5$rugGuag isdEa sGshuM KasuCBd uyuthgBCayGss q65U: HyhWBiEWS* wwhutWdByBEGshutWdtayyGidCugCuluyBruCVhCBus BO0ngsulugayrBhudhayKuduPhs: fiWusu dtyiCusaQaBrugahBd dtBdChBds BOyBe rgussiguadCaMKudhhuMrugahiguVhWuaKyhGhBstayuirhWuuyuthgBtWuMtayCul tuVadC WEWugu0Ptudt GeWadtBMraguChBhWuhWugMBtWuMtayaMdustgiKKdEMuhWBC q6kU: RaghtiyagyGVS* wwhutWdByBEGtadtarhigu wo$_5$uMssBds QgBMsMayysBigtusVdtyiCdE aEgtiyhiguV0BgushsVBtuadsVhgadsrBghahBdVadCgus Cudhayaguas eWugu hgaChBdayMuhWBCsagudBhQuas KyuCiuhBudugEGtBdsiMrhBdadCs,u: HshWsnowarrytahBd sshyy dhsuagyGshaEus BOCulugyBrMudhVOghWugusuagtWaCladtus OBgrgathtayCuMBdshgahBdagutghtay:

nowshadCshBEadsEdPtadhaCladhaEus QgBMnHw: vgshyGVnHwgusuagtWQgu-iudhyGGuyCs ds EWhs dhB MahugaysVrgBtussusVadCudEmduugdE hWahtBiyCKuaCarhuChBudWadtuhWuuOPtudtGadCuC0BthlumdussBOnowsGshuMs: nHwrgB9uthsrgBl CulayiaKyuyussBds dstaydEirtagKBd tarhigu hutWdByBEusVBC0BugdEagBaCMarOBgnowdhahlushBdal Eahu tWayudEus assBtahuCehWyagEumstayu CuryBGMudh MBgu uC0BthlUyG: .ittussOlynHwrgB9uthstad d[iudtu rBytGQgaMue BgTsadCahhgath dtguasuCOdCdEOBgtagKBd tarhigu uC0BghsVKuduPhdEKBhWnHwadCnowdhahlus: pashyGVasnHwEads atturhadtuVhWasHWurBhudhayhB rBshluyGsWaru riKyt rugturhBds BOtagKBd tarhigu hutWdByBEusVdtyiCdEnowVKGWEWyEWhdEhWuGuasKyhGadCKudmuPhs: olugayyVOBshugdEtByyaKBgahBd adCTdBeyuCEu u1tWadEuKuheuudhWunHwadCnowtBMMidhusWByCsrgBMsuOBgattuyugahdErgBEgusshBeagCsgBKishtagKBd tarhigusByihBds:

)prgt csdlgtdutheigde2 ldhgiInruthI%r

fiWuarrytahBd BOKBhWn guthHgwarhigucnHwjadCnguthotuadwarhigucnowj OBgCutagKBd,ahBd shgahuEus CurudCs Bd alaguhGBOQathBgs dtyiCdE uOPtudtGV staya KyhGVudl gBdMudhay MrathVadCutBdBMtQuasKyhG: HyhWBiEWnHwhutWdByBEus BC0ngl ugsahyusByimhBdshBtBMKahtyMahutWadEuVhWuGQatuMa9BgtWayyudEuse hWgusruthhBhWuudugEGtBdsiMrhBdVtBshmC0thludussVadCstayaKyhG: pwHadCfiSHOBgnHwWalusBQagguyuCBdCahaQgBMryBhBgyaKmstayurgBtussusVe WtWagudBhgurgusudhahluBOtBMMugtaymstayurgBtussus: SshaKyshWndE staydEyaesOBgu MugEdEMahugays BghutWdByBEus s dutussagGhBattigahuyGulhgarByahu pwHCahahByagEugstayus adCulayiahuhWuhgiurBhudhayhBuhWugtBMKahtyMahutWadEuBgsirrBghCutudhgay,uCwo$_5$rgBCithBd:

fiBMrgBluhWurugOBgMadtuBOnowhutWdByBEusVhsyTuyGhWahhWuCuluyBrMudhBOdBluysByludhsadCaCsBgKudhMahugaysehWudWadtuCtarhigu tarathGVsuyuthlhGVadCyBeugu EudugahBdtBshsVeyyKugu-igu: fiWuuMugEudtuBOMuMKgadusasayhugdahlutarhigusByihBdssaysBidtyuagEludhWuyatTBOCahasuhsadChWu1rugMudhaytWayyudEushBCuluyBrihygamsuyuthluMahugays d sitWCyihutBdChBds: fdaCCmhBdVhWuuC0BthludussBOWuahu1tWadEugsadCai1yagGQatyhus saysBtiggudhyGyMhuCeWyutBdCithdE BrhM,ahBd BOduheBgTdErgBmtussusVsBOMa9BgMrBghadtuhB MrgBluuOPtudtG: Hhrgusudh MBshhutWdByBEus CuluyBruC agudBhMahigu udBiEWhBsirrBghyagEustayuCurγBGMudhadChWahhWuOihigu BOnHwVadCtiggudhrgB9uthsKudECuluyBruCadCMryuMudhuC: L ludhWahdByagEumstayuryadhsBdhWuhudsBOMuEahBd BOwo5tarhiguCrugGuagagu ryadduCahrgusudhVadCsdtuhWuCuryBGMudhBOadGyagEumstayuryadhsMaGhaTuahMdMa4–20GuagsQgBMhWuCusEdrWasuhBhWuOiyytBMMssBddEVhWuCguthMrathBOnHwBdtyMahuMHEahBdaysBCBusdBhe yydBhyTuyGKuduPhhWutiggudhtyMahuathBdsBlughWudu1h20–24GuagsVidyuss sirrBghuCKGMassluriKyt dlushMudh:

Hyhugdahluy GVnowhutWdByBEusWaluKuudsWBedhByulugaEuhWudahigaytagKBd tGtyuadCtadrBhudhayyGMhEahuBtuadatCPtahBde Wyurg Bl CdEasBigtuBOsu-iushuguCtagKBd: NulughWuyussVnowhutWdByBEusagutiggudhyGMitWyussMahiguhWadnHwBdusVadCu-iayyGQatutWayyudEusVraghtiyagyGguyahuChBhWurBhudhayMraths Bd Magdu utBsGshuMsadChWustayaKyhG:BOhWuhutWdByBEG: RugQBgMdEhWBgBiEWhutWdBmtBdBMtadayGssadCpwHstgitayhBBrhM,uwo$_5$guCithBdsVdtyiCdEasadu1aMryuMadEgBlugushBgahBd: fiWurBhudhayBOnowhBWBeulugWuyr Kayadtur(tWadEusahyagEustayuMaGgurgusudhagBihuhByMhhWuCuEgaCahBd BOu1hguMuyGr(nGurudCudhutBsGshuMsVsitWastBgayguuG9:(BeulugWhWustayaKyhGBOhWuhutWdByBEGadCduuChBriMr

adC CBsu u1hguMuyG yagEu aMBidhs BOsuae ahug arruags as a MaºBg KBHhyudutT hB hWu hutWdByBEG stayumir: SyuthgBtWuM tay Btuad tarhigu Was MrgBluC wo$_5$ tarhigu rBhudhay Kih staydE adC uOPt udtG Mmm rgBluMudhs gu-i gu OghWug gusuagtWraghtiaygyG Ciu hB K BOBiydE BO u1tWadEugs Cig dE tarhigu: fiWu Mrath BOnow Brugah Bds Bd K BC m lugshG s aysB idtyuag adC shi C us hB aCCguss hWuM KBhWyBtayyG adC ah stayu Mish Ku rugOBgMuC: S1ryBg dE hWu tarhigu BOwo$_5$ ah C OOtgudh CurhWs BOhWu e ahug tByi MdVraghtiaygyG d adB1 t tBdC h Bds e Wugu yBe ug K ByBE tay Mahhug tBdtudhgah Bds MaG Ku rgusudh tBMraguC hB sigQatu e ahugs:

fiWu tiggudhtyMahu ath Bds gu-i gu hut WdByBE us adC KBhWhut Wd tay adC EBlugdMudhaytWB tus aKyu hB yuaC hB Ma9BgaKahuMudh BOtagKBd uMss Bds: fiWu MryuMudhah Bd BO KBhW n Hw adC now s tBdhu1h CurudCudhV dtyiC dE yBtay udl gBdMudhay tBdC h Bds Vala yaKyu gum sBigtusVadC hWu rg MagG EBays BOhWu tagKBd tarhigu rgB9uth fd hWu KgBaCug tBdhu1hVayhWBi EWKBhWn Hw adC now gurgusudhs Ed PtadhaCm ladtuMudhs d tagKBd tarhigu hut WdByBEG adC Wál u rBhudhayVhWuG agu tiggudhyG dBh si OPt udhyG Mahigu adC tBdh di uC gusuagt WadC CuluyBrm Mudh s duuCuC: fiWu MryuMudhah Bd BOn Hw adC now WBe ul ug as a Muad hB rgBCi tu wo$_5$ yBtayyG OBg dCi shg ay arrytah Bds arruags MitW MBgu guaysht yuaC dE hB a duhmugB wo 5 Kayadtu: fiWu i su BOn Hw adC now MaG guCi tu hWu OBBhr g dh BOyBdEngadEu wo 5 hgadsOtg adC ath as a sut BdCagG M h Eah Bd rahWe aG: fiWu g dhuEgah Bd dhB KgBaCug ty Mahu M h Eah Bd shgahuE us MaG dBh gur gusudh a Ma9Bg Bi ht BMu Blug hWu Mum C i M hugM Ki h hWu g MryuMudhah Bd OBg Cut udhgay, uC wo$_5$ tagKBd ahus rgBCi th Bd MaG WBe ul ug PdC Bd hWu yBdEnhugMVMagTuhs guaCGhB dl ush:

vi hig ue BgT d hWu PuyC BOn Hw adC now t BiyC dl Byl u sul ugay al m udi us OBg Oghwug u1ryBgah Bd adC Cul uyBr Mudh o dur gBM s dE C gut h Bd s hWu Br h M , ah Bd BOKBhWhut WdByBE us OBg udWadtuC uOPt udtG adC t Bshm OOtth ludussVrugWars hWgBi EWhWu guP du Mudh BOtarhigu Mahug ays Bg r gBtuss udE duug dE hut Wd - i us: HCC h Bday GVgusuagt WuOBghs t Bi yC OBti s Bd staydE ir hWusu hut WdByBE us QgBM r yBh hB dCi shg ay yul uysV aCCguss dE t WayyudEus guyahuC hB dQashgi th giuVudugEG gu-i gu Mudhs V adC udl gBdMudhay Mraths ayBdE hWu e aG: wByyaKBgah Bd Kuhe uud ataCuM aV dCi shgGVadC r Byt GMaTugs t Bi yC Qat yhahu hWu MryuMudhamm h Bd BOyagEumstayu n Hw adC now rgB9uths Ve Wyu dhugC st rydagGshi C us t Bi yC u1ryBgu dBluy dhuEgah Bd shgahuE use hWBhWugtagKBd tarhigu adC gudue aKyu udugEG hut WdByBE us: vighWugMBguV hWugu s a duuC OBg t Bdh di uC MBd hBg dE adC assussMudh BOhWu udl gBdMudhay adC s Bt Bm ut BdBM t MrytahBds BOe Cusr guaC n Hw adC now CurtyBGMudh hB udsigu hWu g yBdEnhugM si sha daK yhG adC uOOtth ludussd t BMKah dE ty Mahu t WadEu:

rF2h1a us lx gidx1e gt li1f s1lgt dlul2y 2t l

%y t vu nc 0uC22Ox g h dE – Bg E day CgaOhVvBgMay adayGs sVn aha ti gah Bd: **mul1y u P s y lu3Ox** g h dE – Bg E day CgaOhVvBgMay adayGs sV n aha ti gah Bd: **Ri1vut 4u Ds y ui1Ox** g h dE – gul ue & uC h dEV. i r ugm l s Bd VvBgMay adayGs s: **k2gi; 1gd wp Duiut 14gcgdOx** g h dE – gul ue & uC h dEV. i r ugl s Bd: **nc2ddut hig I 2 uicddOx** g h dE – gul ue & uC h dEV n aha ti gah Bd: **- s hg51 npI s y 22Ox** g h dE – gul ue & uC h dEV. i r ugm l s Bd V* uhWBCByBEGVn aha ti gah Bd VwBdtur hi ay, ah Bd:

I 2 cuiul1gt gb gy e2l1t ; 1tl2i2dl

fiWu ai hWBgs Cut yagu hWah hWuG Wál u dB TdBe d t BMr uh dE Pdadt ay dhugushs Bg r ugsBday guyah BdsWr s hWah t Bi yC Wál u arruaguC hB d[iudtu hWu e BgT gur BghuC d hWs r arug:

I ulu u5u1cuf 1c1lv

n aha e yyKu MaCu al a yaKyu Bd gu-i ush:

F2h2i2t 2d

q2U H:n:a:H: L WBsW. i MMagG BOL yBKay wy Mahu Hth Bd ah wo R 56 %d huC Nah Bds v gaMue BgT wBdl udh Bd Bd wy Mahu wWadEuV%d huC HgaK SM ga hus 505kVr: 5:
q5U %r. :S:R: HEudtGVfiWu. Bi gtus adC. Byi h Bds3vBss yvi uysV505k: WHrs3fIfle e e :ura: EBl fdi hg udhr Byi h BdfBsBi gtus nadCnsByi h Bdsn6Bss yn0 uys:
qkU H: p uKugV* : (yCuKgadChV. :np: n al CsBdVD: F lugBV(: %sMadVfi:(:F: N ur aV I : (BgdKBshuyVn uMBdshgah Bd BOC gut h Bt uad tagKBd tar hi gu i s dE ud tar si yah uC sByl udh sVwWuM: SdE: D:) í 0 c505kj 2)) 2) 0V WHrs3fIfCB :BgEf20:2028f!9 tu9505k:2)) 2) 0:
q) U fua Vn gut h H g war hi gu: WHrs3fIfle e e : ua:BgEfludugEGnsGshuMfltagKBdnnar hi gum i hysah Bd nadCnsBgaEufIC gut hna gnar hi gu: cHttussuC . ur huMKug 505kj:
q4U fua Vwo 5 war hi gu adC %hysah Bd: WHrs3fIfle e e : ua:BgEfludugEGnsGshuMfltagKBdm tar hi gum i hysah Bd nadCnsBgaEufltB5nar hi gunadCnihysah Bd: cHttussuC . ur huMKug 505kj:
q8U * : o , Tad V. :R: NaGaTVH:n: Fi , Vx : DadEVwi ggudhshahi s adC r yags BOC gut h a g tar hi gu hut WdByBE us V . t udtu 54 c) j c5055j 20k; ; 0V WHrs3fIfCB :BgEf20:2028f!9 st :5055:20k; ; 0:
qíU I : wut ya x Wahe yystayu C gut ha g tar hi gu X H í 4 rugt udhr g tu CgBr Vgur BghsaGsV 505k: WHrs3fIfle e e : Eguud K , :t BMflaghtyufle Wahna ynst ayunC gut hna gnar hi gunf4m rugt udhrng turCgBr ngur BghsaaGsü 3Z 3hu1h = fiWu / 50t Bsh/ 50BO/ 50t agKBd/ 50guMBl ayVátt BgC dE/ 50HB/ 50HWu/ 50due / 50adayGs s:
q6U z: n al CVn gut h FuMBl ay BOwagKBd n B1 Cu QgBM o t uade ahug: WHrs3fIfla gram: udugEGEBl flhut WdByBE usfu1ryBgahBgGnBr tsfIC gut hnBt uadnar hi gu:
q; U w: pu ~i úgúVF:D HdCgusVfi: zBCudVfi: wBde aGVF:H: (Bi EWBdVD.f: (Bi suVL: * agu adCVL:R: RuhugsVL:F: $ ad nugx ugOVH: HWyshgBMVF:* : HdCgue Vp: z Br rVD.L: wadaCuyVR: wa sV. :w: n BduGVw. Sdg EWfVR: vg uCydEshu dVw: (i dh dEOBgCVH:I : Da dVw: DBi gCa dVS: I ah BVF:v: I uuy dEVI : I yu d L ByCue 9TV. : pul sVR: pul GV* : pBMasVz : RBi yhugV* :F: Fai rat WVD . t We dEugV. : . ht Wz:n: . hBt TugVN: $ Bl GV. :] au WuVN:] udEVfiWu EyBKay tagKBd Ki CEuh 2; 4; –5022 VSaghW. GshuM . t udtu n aha 4c2j c502kj 284n2864: WHrs3fIfCB :BgEf20:42;) flussCn4n284n5502k:
q20U No HHVpHfiS. fi o wSHN wHFz o N n HfiH HfipH. . (o x . H . fL NfvfwHNfi n SwpfNS fN o wSHN wo 5 * SH. %FS* SNfi. V505k: WHrs3fIfEyBKay Btuad:dBaa: EBl fhyahushnBt uadnagKBdn6ahanahyasnsWBe snans Ed Ptadhn6uty dumdnBt uadnB5m Muasi guMudhsft:
q22U S:S: HEudtGVo tuad at C Ptah BdV505k: WHrs3fIfle e e :uua:ui gBra:ui fl MsflBt uadm at C Ptah Bdü 3Z 3hu1h = o l ug/ 50HWu/ 50yash/ 50M yBd/ 50 GuagsVg Bg/ 50HB/ 50HWu/ 50 dCi shg ay/ 50gul Byi h Bdj: cHttussuC . ur huMKug 505kj:
q25U * : RayV$: I agay i hiV. : * ay TVS 1r yBg dE hWu RBhudhay BOwagKBd war hi gu V %hy, ah Bd VadC . hBgaEu d zayht . ua FuE Bd wBi dhg us3H Ful ue BOww%. Rahudhs QgBM 5000 hB 5055VRgBt ussus 22c5j c505kj 804:
q2kU . : wWBe CWgGVb: I i MagV. : . Wg l ashal aV. : I : RahuyVD. : . adEe a VH gul ue Bd hWu gut udhst udh Pt adC t BMMugt ayr gBEguss Bd hWu C gut ha g tar hi gu hut WdByBEG hB MadaEu ah MBsr Wtg t wo$_5$ t Bdt udhgah Bds adC Oh i gu r ugsr ut hl us VSdugEG vi uyk í c24j c505kj 20í kk–20í 4í VWHrs3fIfCB :BgEf20:2052flat s:udugEGO uys:5t 0k; í 2:
q2) U N: * t ~i uudVI :$: L BMus Vw: * t wBgM t TVI : z yi Mad hWaV* : R st BhhaVD. x yt B1V H gul ue BOC gut ha g tar hi gu cn Hwj 3 staydE i r t BMMugt ay hut WdByBE us adC dd Bl ah dE OBg hWu Oh i gu VRgBEguss d SdugEG k ckj c5052j 0k5002VWHrs3fIfCB : BgEf20:2066f!5428n206k flaKO2t u:
q24U * : vas WVo : SP MBl aVw: z guGugVfiut WdBmut BdBM t assussMudh BOwo 5 C gut ha g tar hi gu r yadhsVD. wyuad: RgBC: 55) c502; j ; 4í –; 60V WHrs3fIfCB :BgEf20:2028f!9 9t yur gB:502; :0k:068:
q28U w:* : DaGagah WdaV* t Wuy@I agi dagah WduV. i Mi Ci @HdCgudatt V. aga @(ai Eud V (ads HTsuyVFul ue Bd C gut h Bt uad tar hi gu cn o wj hut WdByBE us VRgBt uuC dEs BO hWu 28hWL guudWBi su Las wBdhgBy fiut WdByBE us wBdOtgudt u cL (L fin28j c5055j:
q2í U L: o , d n gut ha g tar hi gu3H y hyu WshBgGVHCl adt u st udt u due s c5055j:
q26U o i g 9Bi gduG hB E EahBd stayu: WHrs3fIfty Mue BgTs:t BMflr i gr Bsu:
q2; U war g t Bgd: WHrs3fIfty Mue BgTs:t BMflgBaCMar flt ar g t Bgd: cHttussuC Hi Ei sh 505kj:
q50U fiWu e BgVC's Pgsh C gut ha g tar hi gu Qat yhG t BMK duC e hWwo$_2$ shBgaEu: WHrs3fIfl ty Mue BgTs:t BMflr yadhmagt ht n6B1:
q52U o gt a3 hWu Pgsh yagEumstayu r yadh: WHrs3fIfty Mue BgTs:t BMflgBaCMar flBgt a:
q55U fuaV%dyBt T dE hWu r Bhudhay BOC gut ha g tar hi gu3 s staydE i r hWgBi EWtagKBd MagTuhs r Bss KyuX fSH c505kj:
q5kU n gut ha g tar hi gu3 Bi g hut WdByBEG hB tar hi gu wo$_2$: WHrs3fIfty Mue BgTs:t BMfl C gut hna gnar hi gu:
q5) U . : nui h, VH: zagCBe Vp OutnGr yu assussMudh BOad dCi shg ay C gut ha g tar hi gu r gBt uss KasuC Bd hu Mr ugah i gu–l at i i M se dE aCs Bgr h Bd VNah: SdugEG 8 c5j c5052j 50k–52k VWHrs3fIfCB :BgEf20:20k6fls) 2480n050n00í 2m:
q54U L: puBd, BVR. : vudduyVN: . WaWWH wBMr agah l ushi CG BOC Oh gudhs BgKudhs d hWu t Bdhu1h BOC gut ha g tar hi gu cn Hwj 3ul ayi ah Bd BOTuGr ugOBgMadtu dC tah Bgs ad C t BMr ag sBds VHr r y. . t : 25 c4j c5055j 5826V WHrs3fIfCB :BgEf20:kk; 0fl arr 25045826:
q58U L: puBd, BVo: * e aKBd9uVR:. : vudduyVN: . WaWVSdl gBdMudhay rugOBgMadtu BO C OOhgudhs BgKudhs i su C OBg C gut ha g tar hi guV. i sha d: RgBC: wBdsi M: k5 c5055j 202–222V WHrs3fIfCB :BgEf20:2028f!9srt :5055:0) :00) :
q5íU (:~: HdWVfi:R:~: puVN: n a puVQ:Q: pi Vfi:fi: ni BdEVD. Lagd ugVS: F Bt Wuyum Nue ayV. :] Wad EVN:(: o WVw: o ui gdEVw: STTae ahr ad hVfi:n: NEi GudV~: fi: NEi GudVfi:n: NEi GudVfi:N: NEi GudVfi:p: figadVfi: I i d si uVF: fiadBi uV . : fiaTaWasWVfi:z: * dW(:fi: puVfi:N:* : RWáMVfi:H:(: NEi GudVHdh K Bhts d si gQatu e ahug BOSash adC . Bi hWuash Hs ad t Bi dhg us3a OBti suC gul ue Bd t Bdha M dah Bd sha hi sVr Byi h Bd sBi gtus Vr Bhudhay gsTsVadC Oh i gu r ugsr ut hl us V . t fiBhay Sdl gBd í 8) c5052j 2) 5684V WHrs3fIfCB :BgEf20:2028f!9 st HBhudl :5050:2) 5684:
q56U %HS HgaKyu padC 2; 82n505kV505k: WHrs3fIfle e e :Mat gBhgudCs:duhfl t Bi dhg us fl HFSfli au flagaKyunyadC:

q5; U n:x : (ae TugVF: wgBr r V* : z BBdsadugV%r hnTu BO, e hhug Bd t adh K Bhts KG g t u co gG, a sah l a p:j d tBdhnM dahuC sB yVD. (a, agC: * ahug: 58k c502kj) 46–) 88:

qk0U Bi g shBgGV505k: WHr s3fIftagKBdudE duug dE:t BMfIBi gnsaBgGF:

qk2U R: HyuhaVH: FuGa uV* : HG3WagVH: (assadV* : FaWM Vn gut h Btuad t ar hi gu3 hWu uMugEudt u BOuyut hgBt WuM tayr gBt ussus OBg Btuad t tagKBd guMBl ayVS dugE: Sdl gBd: . t : c505kj VWHr s3fIfCB :BgEf20:20k; fICkuu02) í 2a:

qk5U n:x : I u hWL: (ByMus Vn: . h HdEuyBVI : (u CuyVH RgBt uss OBg war hi g dE wo 5 QBM hWu HhMBsr WuguVDBi yu 5c6j c5026j 24í km24;): WHr s3fIfCB :BgEf20:2028ft9 9Bi yu:5026:04:008:

qkkU H: . BC - Vb: HKCi yahOVz: H ssaVH: o shBl agVN: NassagV* : SymNaasVH: HMVaMuCV H gul ue Bd r gBEguss MaCu d C gut h a g t ar hi gu BOwo 5 VSdl gBd: fiut WdBy. fddBl : 5; c505kj 205; ; 2V WHr s3fIfCB :BgEf20:2028ft9uh:5055:205; ; 2:

qk) U D. i dV* :] WaBVp: (i adEVfi:] WadEV~: x adEVF ut udh r gBEguss Bd C gut h a g t ar hi gu BOt agKBd C B1 Cu Vwi ggr o r d: L guud . i sha daKyu wWuM:) 0 c505kj 200í 45V WHr s3fIfCB :BgEf20:2028ft9t BEst:505k:200í 45:

qk4U v: z ag, aEyVw: L BgE Vv: * ad V* : Rugi , , d V. t guud dE shi CG BOC OBgudhaM dum KasuC sByi h Bds as sBgKudhs OBg C gut h wo 5 t ar hi gu QBM H gVHw. . i sha d: wWuM: SdE: 6 ckí j c5050j 2) 02k–2) 052V WHr s3fIfCB :BgEf20:2052fl at ssi st WuMudE:0t 0k600:

qk8U I : * aCW V. : Rai yi TV. : n WahWg Vv: wgui h EV%dCugshadC dE udl gBdMudhay hgaCunBO8 adC gusBi gt u CuMadC BOC gut h a g t ar hi gu hut WdByBE us hWBi EW t BMr agah l u yOunGt yu assussMudhVNah: SdugEG 8 c22j c5052j 20k4–20)) VWHr s3fIfl CB :BgEf20:20k6fs) 2480n052n00; 55n8:

qkíU D.D zuyz gi dBV* Byut i yagG fMr g dhuC RByGMugs VwWuM Ful 22; c2j c502; j ;) –22; VWHr s3fIfCB :BgEf20:2052flat s:t WuMgul :6K002í 2:

qk6U x : . t Bhhn gut h a g t ar hi gus hWu rahWhB uM ss Bds hagEuhsV505k: WHr s3fIfle e e : ts gB:ai fludfldue sflayyflaght yusf505kfI9 dufIC gut hma gnt ar hi gu:

qk; U b: pi Vb:] WrVb:] WadEVI : x adEV. GdlhWus , dE l haM d S MByut i yagyG Mr g dhuC r ByGMugs l a r gut r hah Bd r ByGMug , ah BdVD. wWuM: SdE: na ha 8) ckj c502; j 20) 4–2040V WHr s3fIfCB :BgEf20:2052flat s:9 tuC:6K00;)) :

q) 0U F:nfi : w. fF o VRgB9 ut h SNwo FS3v day gur BgHVc5052j:

q) 2U RgB9 ut hs suyut huC OBg RWasu 5 BOHWu n gut h a g t ar hi gu ad C Eguud WBi su Eas guMBl ay r gBEgaMMuuV5055: WHr s3fIfle e e :EBl : i TfIEBl ugd Mud hfIr i Ky t ah Bds fIC gut hma gnt ar hi gur ad CnBHWugn Eguud WBi sur Easr guMBl ay nhut WdByBE usr nBMr uh h Bd fIr gB9 ut hsm suyut huCn0Bgr n Wasur n8OHWurC gut hma gnt ar hi gur ad CnEguud WBi sur Easr guMBl ay rn r gBEgaMMuui gBysr gBGt urn yt:

q) 5U (: I aMGaKV. : wWuy ar ad Vo : fial a TTBy V* : * us KaWVD. I : z W HBVfi: I WaCuM Vf: I gr t Wd TBl a VH: HWMaCVH: p: HHVH gul ue Bd t agKBd n KasuC MByut i yagyGm Mr g dhuC r ByGMugs cwz * fRj OBg Cuh ut h Bd BOWa, agCBi s r Byi h ads d a- i uBi s sByi h Bds Vw WuMBsr Wugu k06cRh kj c5055j 2k8) í 2: WHr s3fIfCB :BgEf20:2028ft9 t WuMBsr Wugu:5055:2k8) í 2:

q) kU fi:fi: (: $ ad V] : b CadaVR:* : . MBBTugVR:D. wByBuVHdh K Bht i su d OBBC ad Mays e BgyCe CuVe hWa OBt i s Bd HQ, ta3r yi sus adC M di sus VD L yBK Hdh M t gBK F us sh 50 c5050j 2í 0–2í í V WHr s3fIfCB :BgEf20:2028ft99Eag:502; :0í :0k2:

q)) U H gh Wuda™ – wo ₂ QBM H gV5055: WHr s3fIfle e e :ts gB:ai fludfle BgTm hWinsfl r m t BMMugt ay sah Bdf fMagTuhr yat uft t B5Eud: cHt t ussuC Di yG 505kj:

q) 4U * :* : . aC - V* :R: z alhudVQ: * i yuhVw: v guuMadVI : I Bdshas VDf: * agCuyVD fiaddugV n: NEVQ: x adEV. : (Be agCV* :F: (yWH:x : fiWBgdhBdVH r yBhnst ayu CuMBdshgh a Bd BOMBK yu C gut h a g t ar hi gu i s dE Muh ayuBgEad t QgaMue BgTs VHCl : . i sha d: . Gs:) c25j c5050j 5000202V WHr s3fIfCB :BgEf20:2005flaCsi :505000202:

q) 8U D I o (pSF LyBKay fiWugMBshah yai dt Wus r yadh d HCaMs wBi dhG HWáhsi t Ts tagKBd C B1 Cu Bi h BOHWu a gVfiWu Cudl ug r Bsh c505kj:

q) í U p: padEsCBgO. TGhguu pai dt Wus v gsho dna hu wagKBd war hi gu %d hah L gBe G vagMs d hWu NuhWugyadCsVw s Bd c5055j:

q) 6U . : RBe ugVHKBi h3. Byuha g RBe ugV505k: WHr s3fIfle e e :sByuha gr Be ug:PfaKBi hm sf t:

q) ; U H: wWayM d Vn fF Swfi HfF wHRfi%FS3F SwS Nfi n S$ Spo R* SNfi. HNn v%fi%FS RpHN. VL uBS dE duug dE MBd hBg c502; j:

q40U N:x : . hai OBgVH due arr gBat WhB tagKBd t ar hi guV* ffi Nue s c5050j:

q42U n: wWadCyugV* ffi udE duugs Cul uyBr a due e aG hB guMBl u tagKBd C B1 Cu QBM a gV* ffi due s c502; j:

q45U . :* :x : x ysBdVfiWu r Bhudhay BOC gut h a g t ar hi gu i s dE aCsBgKudhs d t ByC ty Mahus V . t udt u 54 c25j c5055j 20448) VWHr s3fIfCB :BgEf20:2028ft9 st :5055:20448):

q4kU . :I : LuKguMag aMVH: * ahWa $agEWusuVI :. :I : FuCCGVb: vBe aC Hyx aWuC Vp: v: ni MúuVL :N: I agad TByBs VRByGMugma CuC M t gBshgi t hi g dE BOMB shi gunsha Kyu Lo nWGKg C , uC * o vs OBg tagKBd C B1 Cu t ar hi gu VwWuM: SdE: D.) í k c505kj 2) 4568V WHr s3fIfCB :BgEf20:2028ft9t u9505k:2) 4568:

q4) U H:* : $ agEWusuVI :. :I : FuCCGV. : . dEWL. :N: I agad TByBs VRugOBgMadt u udWadt u Mudh BOwo 5 t ar hi gu aCsBgKudhs KG %$ hguahMudh8hWu tasu BOsuyOn si r Bghu C Egar Wudu B1 Cu OBaMVwWuM: SdE: D. k68 c5050j 25) 055V WHr s3fIfCB : BgEf20:2028ft9tu95050:25) 055:

q44U fi: fiugBi e VI : figuGugVw: z ai ugV* : * a, , BhhVp Ou t Gt yu assussMudh BOC gut h a g t agKBd t ar hi gu ad C shBga Eu e hWyBe rn agKBd udugEG sBi gt us VSdl gBd: . t : fiut W 44 c28j c5052j 22k; í –22) 22V WHr s3fIfCB :BgEf20:2052flat s:ush2t 0k58k:

q48U D x ad EV. : p V. : n udEVQ:] udEVI : p VD. p i VD. ba dVp: pu VS dugEuh t ad C y Ou t Gt yu assussMudh BOC gut h a g t ar hi gu3a gul ue V. i sha d: RgBC: wBdsi M: k8 c505kj 2–28V WHr s3fIfCB :BgEf20:2028ft9sr t:5055:25:02í :

q4íU * :* :D. Cu DBdEuVD. n auMudVD.* : pBg ai 1V] :D.N: . hu dMaddV* :H:D. (i 9KguEhsV p Ou t Gt yu tagKBd uOPt udt G BOn gut h H g war hi gu sGshuMs e hWshgBdE WQCgB1 Cu sBgKudhs Vfdh D. L guudWBi su Las wBdhgBy 60 c502; j 54–k2V WHr s3fIfCB :BgEf1 20:2028ft9 9EEt:5026:22:022:

q46U D fi ugdad wy Mue BgTs RguC t hs n gBr fd wBsh fiB z uyBe J540fl* h vBg wagKBd FuMBl ay z G 50k0Vwyuad fiut Wd t a c5055j:

q4; U $: * i hWTi Magase aMG FadEagaaVV* :H: x aWaKVI :. :I : FuCCGVL : I aTBs MBsV o : HKCayyaVS:R: val l asVn : Fu day CaVv: L ui , uKgBuTVH: HKCayaVL :N: I agad TByBsV * uhay BgEad t QgaMue BgT — KasuC M 1uC Mahg 1 MuMKgadus OBg tagKBd C B1 Cu sur agah Bd 3gut udha Cl adt us adC O hi gu C gut h BdsVvgBdh: wWuM: 6 c5050j VWHr s3fIfl CB :BgEf20:kk6; fI0WuM:5050:004k):

q80U F: wash gBm: i dB, V* :] aM C HWMaCV* : * ayad TBe sTaVD: wBgBdas VH due guyul adh MuMKgadu arr y t ah Bd3wo 5 C gut h a g t ar hi gu cn Hwj VwWuM: SdE: D.)) 8 c5055j 2kí 0) í VWHr s3fIfCB :BgEf20:2028ft9tu95055:2kí 0) í :

q82U . : vi 9 Tae aVF: . uyGadt WGdVfi: I i d hn Tu VH due shgahuEG OBg MuMKgadumKasuC C gut h a g t ar hi gu VRByGM: D. 4k c5050j VWHr s3fIfCB :BgEf20:20k6fs) 2) 56n050m 00) 5; m:

q85U R: $ uKa WdVH: . t WBy, Vo :] uyhVfiWu r Bhudhay gByu BOC gut h a g t ar hi gu d hWu EugMad udugEG gus uagt Wr gBEgaM—gusi yhs BOa Mi yh n C Muds Bdaya day Gs sV SdugE us 25 c26j c502; j k)) kV WHr s3fIfCB :BgEf20:kk; 0fud2526k)) k:

q8kU H:(: * agh dV(: w: RuagsBdVL : I : . aKa VS:* : o ysudVfdhuEgay 0 d th Bds BOMag du l ughuKgahus d hWu Btuad t agKBd t Gt yu ad C ty Mah u t WadEu M h Eah BdVo du Sagh W) c4j c5052j 860–8; kV WHr s3fIfCB :BgEf20:2028ft9Bduuag:5052:0) :02; :

q8) U R: vg uCyd Eshu dV* : o 'si yy l adV* :x : DBdus VF:* : HdCgue VD (ai t TVH: o ysudVL : R: Ruhugs Vx : Ruhugs VD. RBdEgah, V. : . ht WVL yBKay t agKBd Ki CEuh 5050VSagh W. Gsh . t : na ha n sti ss: 5050 c5050j 2–k:

q84U . :F: wBByuGV. : I y ds TGVn : F: * BggBe Vfi: . a hhugPuyCV. Bt Bhut Wd t ay t Bds Cugah Bds aKBi h Btuad t agKBd C B1 Cu guMBl ayVH dd Ful * ag. t 24 c505kj) 2–88V WHr s3fIfl CB :BgEf20:22) 8fladdi gul nMag dun0k5255n82k640:

q88U fi: fiaTa WusWVx :. : z gBut TugVH:S: z a dKg CEuVfiWu ay Tay d hG ad C hBhay t agKBd C B1 Cu t Bdt udh gah Bd d hWu e BgyC Bt uads VwagKBd wGt yu * BCuyy dEV. wo RS 28 ck0í 6j c2; 62j 5í 2–568:

q8íU x :] WadEVQ: . BdEV* : p i V~: x adEVD. BdEVp: ni adVQ: p V(: bi ad VRBhudhay t ar hi gu ad C t Bdl ugs Bd BOwo c5j QBM Btuade ahug hWBi EWM dugay t agKBd ah Bd V . t fiBhay Sdl gBd 68í c505kj 28246; VWHr s3fIfCB :BgEf20:2028ft9 st hBhudl :505k:28246;:

q86U H:* : (ad t Bt TVw: I : I dEVD. : . hagTVH: * t* ddVH: fi: nal CsBdVSO0t h s BOBt uad at C Pt ah Bd Bd Hdh agt ht Mag du BgEad sMs3a Muhamdayas vSYs t By S l By 20 c20j c5050j)) ; 4–) 42) VWHr s3fIfCB :BgEf20:2005flat uk:8504:

q8; U v: * uy, dugVv: w. * agTVz : H: . u KuyVp: fiBMaduTVo t uad at C Pt ah Bd ad C t Bash ay Mag du dl ughuKgahus3hgat T dE wo c5j uO0t h s QBM suae ahug hB hWu t uyyVHdd Ful * ag. t 25 c5050j) ; ; –45k VWHr s3fIfCB :BgEf20:22) 8fladdi gul nMag dun020) 2; m 020846:

qí 0U z:n: RahhugsBdVv: * BVH: z BgEst WyhuV* : (yushaCVv: DBBsVfi: I g shadsudV . : . i dCuVD. H: lad z BTWBl udVF udue aKyu wo c5j gut GtydE adC sGdhWdht Ouy r gBCi t h Bd d a Mag du udl gBdMudhVRgBt NahyHt aC . t %. H 228 c54j c502; j 25525–2552; VWHr s3fIfCB :BgEf20:20í kfIr das:2; 05kk4228:

qí 2U w. DaGagahWdaV* : * auyi MV. : I agi dagahaWduV. : HdCgudatt V(:H: (ai Eud VF ul ue Bd C gut h Btuad t ar hi gu cn o wj hut WdByBE us VHI a yaKyu ah. . F N) 565; 8; c5055j:

qí 5U H:* :* :D. : ray C dEVH wg h t ay Hday Gs s BOHWu o t uad SO0t h s BOwagKBd n B1 Cu Fu MBl ayl a n gut h H g adC o t uad war hi gu – fs ha . a0u adC . i sha daKyu . Byi h BdXV c5052j:

qí kU p:m-: DadEVH: I B, GgVD* : Fuy r WVS:f: F Bd 9uVp: I a MKVS: z i gEugVD. * GugV p: NEi GudVI :* : Hg, aGi sVfi: z BGugVfiWu Btuad tagKBd adC at C Pt ah Bd Caha sGshuMV. t : na ha 20 c2j c505kj 2k8:

qí) U F: . Wag Pad VF :* : x aEhugl uyCVf: H: n ECaGaVw: Q adEVn: H: $ ugMaasV SyuthgBt WuM t ay t agKBd C B1 Cu t ar hi gu HBt yBsu HWu t agKBd t Gt yu VSdugE: Sdl gBd: . t : 2) c5j c5052j í 62–62) VWHr s3fIfCB :BgEf20:20k; fIC0uu0kk65T:

qí 4U * :n: S saMadVp: HylagaCBVn: pagdugVR: x adEVz: LagEVI : H: p hhai V wo 5 sur agah Bd i s dE K r Byag MuMKgadu uyut hgBC ayGs sVSdugEG Sdl gBd: . t :) c) j c5022j 2k2; –2k56V WHr s3fIfCB :BgEf20:20k; flt0uu00k0kC:

qí 8U f:H: n ECaGaVf: . i yy l adV* : p dVp: (adVx :(: wWudEV(:H: HHe ahugVw: Q adEV H C gut h t Bi r yuC uyut hgBt WuM t ay sGshuM OBg t ar hi gu ad C t Bdl ugs Bd BOwo c5j QBM Btuade ahugVNah wBMMi d 22 c2j c5050j)) 25V WHr s3fIfCB :BgEf20:20k6fl s) 2) 8í n050r8650k5rn6:

qíí U . : I MV* :R: N h, st WuV. :z : Fi OBgVD. F: paTuVI : I : $ agadas Vfi: H: (ahBdV HsGMMuhg t t WBg CunMuC ahuC uyut hgBt WuM t ay r gBt uss OBg wo 5 guMBl ay QBM Btuade ahugVSdugE: Sdl gBd: . t : 28 c4j c505kj 50k0–50)) VWHr s3fIfCB :BgEfl 20:20k; fIC5uu0k60) W:

qí 6U (:n: x yyai ugVv: n * ast BVn : F: (agCGVv: x : x yyaMsVn ul uyBr Mudh BOad uyut hgByGht t ah Bd u1t WdEu MBCi yu OBg hWu s Mi yh a duBi s u1 hgat h Bd BOt agKBd C B1 Cu ad C WGCgBEud Eas QBM dah i gay suae ahugVSdugEG vi uyk2 c5j c502í j 2í 5k–2í k0V WHr s3fIfCB :BgEf20:2052flat s:udugEGO uys:8K05468:

qí ; U ~: p Vb: (i adEV] : RadVD. N Vx : badEVD. p V(ByyBe wVNm fi o 57 w si gOu t u MByut i yagyG Mr g dhuC M t gBsr Wugus e hWl s Kyu yEWh r WBhBt ah ayGht gu Eudugah Bd al a yaK yhG OBg hagEuhuC CuEgaCah Bd BOsi yQaC a, duV . ur : Ri g O fiut WdBy. 5; ; c5055j VWHr s3fIfCB :BgEf20:2028ft9sur r i g:5055:25262):

q60U F: . Wag Pad Vp: z BugVF : * : x aEhugl uyCVn : H: $ ugMaasVo t uad t tagKBd t ar hi gu hWgBi EWuyut hgBt WuM t ayyG dCi t uC d s hi tagKBdah u M dugay, ah Bd i s dE K r Byag MuMKgadu VwWuM: SdE: D.) k6 c5055j VWHr s3fIfCB :BgEf20:2028ft9 tu95055:2k4k58:

q62U * :n: S saMadVI : Raga9 yGVH: fii EadBl Vw: SyCugsWae VN: wWadEVI :H: p hhai Vwo 5 u1hgat h Bd QgBM suae ahug i s dE K r Byag MuMKgadu uyut hgBC ayGs sVSdugE: Sdl gBd: . t : 4 c8j c5025j í k) 8–í k45:

q65U . t ayaKyu n gut h o t uad war hi gu cn o wj hut WdBy BEG Cul uyBr uC ah wayhut WV5052: WHr s3fIft ar hi gat Bgr : t BMfle Wahha un6Bfl:

q6kU I :* : DBWdsBdVH:S: I dEVD. * : . uKi ghWVwBi yBMuhg t fiwo 5 ada yGsus OBg Mag du shi C us@ad dhgBCi t h BdV* ag wWuM: 28 c2j c2; 64j 82–65:

q6) U R:] WadEVb: (i BVv: x adEVv: vadEVn: . i dVn gut h uyut hgBt WuM t ay sua e ahug sr yh h dE OBg Eguud WGCgBEud adC agh Pt ay guuG9VHw. Hr r yuC SdugEG * ahug ays 8 c2) j c505kj í 8k8–í 8) 5V WHr s3fIfCB :BgEf20:2052flat sauM:kt020í 2:

q64U w. ni VD. F: ni VQ:] WaBVv: wWudEV* :S: Hy VQ: vudEVfiguahMudh BOKgat T sWe ahug Fo Kg du l a K r Byag MuMKgadu uyut hgBC ayGs sVfdC: SdE: wWuM: Fus: 80 cí j c5052j k224–k25;:

q68U D: F lugBVH: p uKugVw: . dBCEgassV] : NuayV* : (yCuKgadChVx : LaMKyuV I : (BgdKBshuyVn uMBdshgahBd BOC guth Btuad tagKBd tarhi gu i s dE WByyBe PKug MuMKgadu t Bdhat hBgsVwWuM: SdE: D:) í 0 c505kj 2) k686VWhrs3flfCB :BgEfl 20:2028f9tu9505k:2) k686:

q6í U H: I yi C, uVn: . ByadT V* : pu9ui duVF: badaE V* : fsW VN: FaGt Wai CWi g V R: HdashasVN: z BGyuV. : (i Vz Bt uMudh QBM hWu Btuad3 WGKg C M tgBK aym uyuthgBt WuM tay M dugay, ah Bd BOwo c5jV . t udt u 54 c20j c5055j 204248V WhrS3flfCB :BgEf20:2028f9 st :5055:204248:

q66U (: p V] : fiadEVQ: Q dEVn: Li BVp: wi VQ:nj: * aBV. hi CG BOwo 5 tarhi gu KG suae ahugadC hs gu dOBgtuMudhVSdugEG 28) c5026j 22k4–22)) :

q6; U (: p V] : fiadEVN: p Vp: wi VQ:nj: * aBV* utWad sM adC rgBtuss shi CG Bd shuuysyaE udWadtuMudhOBg wo 5 tarhi gu KG suae ahugVHrry: SdugEG 5í 8 c5050j VWhrs3flfCB : BgEf20:2028f9aru dugEG:5050:224424:

q; 0U D: DuBdV* :nB I MVwo 5 shBgaEu adC wawo k rgBCi th Bd i s dE suae ahugadC ad ayTay dCi shg ay KGmgBCi thVwWuM: SdE: D: kí 6 c502; jVWhrs3flfCB :BgEf20:2028fl 9tu9502; :255260:

q; 2U D:] WadEV] :F: vWBdEV* :v: ~i gusWVR: p dEaVwagKBd C B1 Cu su- i ushgah Bd l a Eas WGCgahus3a r Bhudhay rahWe aG hBe agC Cut agKBd , ah BdVS dugEG vi uy k) c; j c5050j 2045; –204) 8VWhrs3flfCB :BgEf20:2052flat s:udugEGO uys:0t 05k0; :

q; 5U f: . i yJ ad VH: L BgGat Wil Vf: H: n ECaGaVQ: p V(:H: Hhe ahugVn: H: $ugMaasV w: Q adEVwBi r ydE uyuthgBt WuM tay wo 5 t Bdl ugs Bd e hWwo 5 tarhi gu VNah wahay:) c22j c5052j ; 45–; 46VWhrs3flfCB :BgEf20:20k6fls) 2; 5; n052n008; ; n:

q; kU nul uyBr Mudh BOfiWd v yM wBMr Bs hu (BuyBe v Kug * uMKgadus OBg n gut ho t uad war hi gu: war hi gaV5052: WhrS3flftar hi gat Bgr : t BMfle Wahm unGBf:

q;) U S- i dBg adC war hi ga r raghdug hB Cul uyBr Btuad tagKBd guMBl ayVc505kj:

q; 4U . : vguuMadVn ul uyBr Mudh BOad o OOnWBguV. hadCnhyBdu . GshuM OBg SOPt udh wo 5 FuMBl ay QBM o t uade ahugVway OBgd a fdsh hi hu BOfiut WdByBEG cway hut WjV505k:

q; 8U . : vguuMadVS yut hgBt WuM tayG * BCi yahuC wB5 FuMBl ay QBM o t uad x ahugsV * assat W suhhs fdsh hi hu BOfiut WdByBEG c* ffij V505k:

q; í U . : vguuMadV(GCgByGht . BOhud dE BOo t uad x ahug OBg wagKBd n B1 Cu FuMBl ay. %d l ugs hG BONBghWn a TBha SdugEG & Sdl gBd Mudh ay Fusuagt Wwudhug c%Nn m SSFwj 5055: Whrs3flfagr amn: udugEG:EBl fhut WdByBE usfIrgB9ut hsfIWGCgByGht m sBOhud dEnBt uadm ahugmagKBdmG B1 CurguMBl ay.

q; 6U S: w: pa Ryadhu Vn: H: . MBduhh VD: x adEVH: Hynfii gT VQ: wWudVn: DassKGVL: N: . adhV. ay du e ahugKasuC M dugay, ah Bd r ahWe aG OBg E EahBddumat ayu wo 5 MadaEuMudhWHw. . i sha d: vWuM: SdE: ; ckj c5052j 20í k–206; VWhrs3flfCB :BgEfl 20:2052flat ssi st WuMudE:0t 06482:

q; ; U (: x adEVD: badVx : . BdEVw: D adEVfi: Qi VfBd u lt WadEu MuMKgadu guyahuC r gBt ussus hBe agCs tagKBd t arhi guVi hy, ah Bd adC shBgaEu3 ti ggudh hgudCs adC r ugsr ut hl usV. ur : Ri g O fiut WdBy: 5; 8 c5055j VWhrs3flfCB :BgEf20:2028f9 sur ri g:5055:252k; 0:

q200U H: f , i TaVI : (asWMBhBV(: NaEasae aVI : I i MaEa Vb: badaE sae aVH: baMasaT V wagKBd C B1 Cu gut Bl ugG QBM tagKBdahu sByi h Bds i s dE K r Byag MuMKgadu uyuthgBC ayGs sV. ur : Ri g O fiut WdBy: 202 c5025j) ; –4; VWhrs3flfCB :BgEf20:2028fl 9sur ri g:5025:0; :028:

q202U . : $ayi g V. :I : I ae ahgaVF uCi t uC gua Eudh gu Eudugah Bd udugEG OBg wo 5 tarhi gu e hWK r Byag MuMKgadu uyuthgBC ayGs sVvi uy RgBt uss: fiut WdBy: 52k c5052j V WhrS3flfCB :BgEf20:2028f90 r gBt :5050:2088; 2:

q205U F: . Wag Pad V(:w: l ad Cug x ayVF:* : x aEhugl uyCVn: H: $ugMaasVvBi ydE MadaEuMudh d Bt uad t tagKBd t arhi gu l a dns hi uyuthgBt WuM tay K r Byag MuMKgadu uyuthgBC ayGs sVvWuM: SdE: D:) 46 c505kjVWhrs3flfCB :BgEf20:2028f9 tu9505k:2) 2) 0í :

q20kU (: pi Vp: x adEVF: x Gt sTVR: N: R dhai gBV. : p dV~i adh OG dE hWu T duh t sm udugEuh t s r ugOBgMadt u hga CuBOO d K r Byag MuMKgadu uyuthgBC ayGs sVD: * uMKg: . t : 825 c5050j VWhrs3flfCB :BgEf20:2028f9MuMst :5050:2265í ; :

q20) U x :D: wa VN: DaBVx ashue ahugayTay d hG aCC h Bd as a dBl uyar r gBat WOBg Bt uad duEah l u tagKBd uM ss BdsVfddBl ah Bd ct aMKj k c) j c5055j 2005í 5VWhrs3flfCB : BgEf20:2028fl91 dd:5055:2005í 5:

q204U . .ó': . d' K9BgdsCBhhgVz: . EQ ssBdVw: * ag ud Vn: L ByCKugEV. :F: L syasBdVS: (: o uyTugsVwagKBd C B1 Cu shBgaEu hWgBi EWM dugay tagKBdah BdVNah i gu F ul : SagshWSdl gBd: 2 c5j c5050j ; 0–205VWhrs3flfCB :BgEf20:20k6fls) k02í n02; n0022m 6:

q208U H: L ai haMV* :I : * BdCayVF ul ue BQgut udh hgudCs adC l ag Bi s hut Wdl - i us OBg wo 5 tarhi gu3sr ut ay uMr Was s Bd K r Was t aM du sByl udhsVvi uy kk) c505kj 258828:

q20í U * : * BWaMaC maEWMByau VH: (a9, aCuWR:] aWuC , aCuWF: H, dV . :] udCuWKBi C VSl ayi ah Bd BOWGKg C , uC rugOBgMadt u BOaM du st gi KK dE r yadh KasuC Bd u lugEGVudugEGVudl gBdMudhay VadC ut BdBM t rgBsr ut hs3a Eas se uuhud dE r yadh tasu shi CGVSdugEG: 52) c5052j VWhrs3flfCB :BgEf20:2028f9 udugEG:5050:226í 24:

q206U L: fi: F Bt Wuyu VfiWugMay CuEgaCah Bd BOaM dus OBg wo 5 tarhi gu Vwi gg: o r d: wWuM: SdE: 2 c5j c5025j 26k–2; 0VWhrs3flfCB :BgEf20:2028f9t Bt Wu:5025:05:00) :

q20; U w: wWaBVb: n udEVF: n ue yVD: zauGudsVQ: vadVRBshmnBMKi sh Bd tagKBd tarhi gu V F udue : . i sha d: SdugEG Ful : 2k6 c5052j VWhrs3flfCB :BgEf20:2028f9 gsug:5050:220) ; 0:

q220U Q:] WadEVQ: (uVfi: Li dCugsudVRBshmnBMKi sh Bd tagKBd tarhi gu e hWa Eas sur agah Bd MuMKgadu3r agaMuhg t shi CGVtarhi gu t BshVadC u lugEG adayGs sV SdugEG vi uy 5í c6j c502kj) 2kí –) 2) ; :

q222U L: (: wWB V(: D: . BdEV. : puuVDb: I MV* : m: * BBdVR: D: bBBVS yut hgBt WuM tay C gut h wo 5 tarhi gu hut WdByBEG i s dE guCB1 mat h l u BgEad t MByut i yus hB at Wul u tagKBdnduihgay hGVNadB SdugEG 225 c505kjVWhrs3flfCB :BgEf20:2028f9 dadBud:505k:206425:

q225U N: * t ~i uudVI :$: LBMusVw: * twBgM t TVI : z yi MadhWayV* : R st BhhaVD: x yt B1V H gul ue BOC gut h a g tarhi gu cn Hwj 3staydE i r t BMMugt ay hut WdByBE us adC ddBl ah dE OBg hWu O hi gu VRgBEguss d SdugEG k ckj c5052j VWhrs3flfCB :BgEfl 20:2066f5428n806kflaKO2tu:

q22kU (: I MV. :D: (e adEVI :. : puuVNBl uys WBght i h ush Mah Bd MuhWBC OBg gu Eudugah Bd udugEG BOaM du sByl udhs d ad aKsBgr h BdnKasuC tagKBd tarhi gu r gBt ussVSdl gBd: . t : fiut W) ; ckj c5024j 2) í 6–2) 64:

q22) U I : $uyhMadVz: . dEWS:L: (ughe tW(i Mad adC udl gBdMudhay Mr at h assussMudh BOr Bsht BMKi sh Bd wo 5 tarhi gu OBt is dE Bd uM ss Bds QBM aM dum KasuC st gi KK dE sByl udhs hB a gVSdl gBd: . t : fiut W)) c) j c5020j 2) ; 8–2405:

q224U H: p uKugV* : (yCuKgadChV. :np: nal CsBdVD: F lugBV(: %sMadVfi: (:F: N ur aV I : (BgdKBshuyVn uMBdshgah Bd BOC gut h Bt uad tagKBd tarhi gu i s dE udt ar si yahuC sByl udhsVwWuM: SdE: D:) í 0 c505kjVWhrs3flfCB :BgEf20:2028f9 tu9505k:2)) 2) 0:

q228U H: fdEl agsCBhhgVwBMr ag sBd BOC gut ha g tarhi gu hut WdByBEG hB r B dhsBi gt u wo 5 tarhi gu d ft uyadCVc5050j:

q22í U H: La MKWgV* : fial Bd Vn gut ha g tagKBd tarhi gu adC su- i ushgah Bd:3WBe he BgTs adC WBe ht Bi yC t Bdhg Ki hu hB ty MahumWadEu M h Eah Bd Vo du SaghW2 c) j c502; j) 04–) 0; VWhrs3flfCB :BgEf20:2028f9Bduuag:502; :22:008:

q226U * : SgadsVS:. : . ad, nRúgu, Vn: R: (adaTV] : wyi yBe Vn: * : F u dugVL: H: * i ht WVn gut h a g t arhi gu3r gBt uss hut WdByBEGVhut WdBmt BdBM t adC sBt BmBy ht ayt WayudEusV SdugE: Sdl gBd: . t : 24 c) j c5055j 2k80–2) 04VWhrs3flfCB :BgEf20:20k; fl C2uu0k45ka:

q22; U v: p VD: L aBVQ: p Vb: p VQ: (uVp: wWudVb:] WadEVRgur agah Bd BOMaEduht MByut i yagyG Mr g dhuC r ByGMugs O dt h Bday, uC tagKBd dadBhi Kus OBg WEWjG suyuthl u guMBl ay BOag shByBt Wt at CVD wWgBMahBEg H 2805 c502; j 286–2í í V WhrS3flfCB :BgEf20:2028f9t WgBMa:502; :08:0) k:

q250U F: . uyGadt WGdV* : Hg GBs WV. : vi 9Tae aVfiWt Tduss uOOnt h Bd wo 5fIN5 sur agah Bd d CBi Kyu yaGug r uKa1n8284í flRn* . MuMKgadus V* uMKgadus 6 c) j c5026j 252V WhrS3flfCB :BgEf20:kk; 0flMuMKgadus60) 0252:

q252U R: * : zi CCVI :D: * saG KVw: S: fiahhugsWayyVz: . : L WaduMVI :D: FuGdByCs VN: z: * t I uBe dVn: vg hst WVL as sur agah Bd MuMKgadus QBM r ByGMugs BO dhg ds t M tgBr BgBs hGVD: * uMKg: . t : 542 c2j c5004j 58k–58; VWhrs3flfCB :BgEf20:2028f 9MuMst :5004:02:00; :

q255U w: b: wWraWD: puuVb: zaBVD: . BdEVfi: n6: zauV(EWmugOBgMadt u r BgBi s tagKBdm , uByhu M 1uCnMahg 1 MuMKgadus OBg wo 5fIN5 sur agah BdVD: * uMKg: . t : 855 c5052j 22; 0k2VWhrs3flfCB :BgEf20:2028f9MuMst :5050:22; 0k2:

Updated Buildings Sector Appliance and Equipment Costs and Efficiencies

March 2023

Independent Statistics and Analysis
U.S. Energy Information Administration

www.eia.gov
U.S. Department of Energy
Washington, DC 20585

The U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy (DOE), prepared this report. By law, our data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government. The views in this report do not represent those of DOE or any other federal agencies.

March 2023

Updated Buildings Sector Appliance and Equipment Costs and Efficiencies

Energy used in the residential and commercial sectors provides a wide range of services, including heating, cooling, lighting, refrigeration, cooking, and numerous other end uses. The U.S. Energy Information Administration (EIA) conducts two buildings-sector surveys—the *Residential Energy Consumption Survey* (RECS) and the *Commercial Buildings Energy Consumption Survey* (CBECS)—that provide information on the equipment stock and energy consumption within existing buildings. However, these surveys do not directly gather other information that we need to project future energy consumption, such as equipment cost information or nameplate efficiency ratings.

The Residential Demand Module (RDM) and the Commercial Demand Module (CDM) of the National Energy Modeling System (NEMS) use equipment cost and performance technology menus that represent competing options for most of the major end uses. The contracted reports in Appendixes A–D provide the information basis on which these menus can be built, focusing on cost and efficiency characterizations across equipment and fuel types. Previous editions of the *Annual Energy Outlook* (AEO) used similar contracted reports.

Multiple equipment classes and types are represented in these menus so that the projected equipment stock can change over time in response to fuel prices and other factors that affect equipment choice, such as appliance standards. The equipment menus interact with other NEMS parameters to determine market shares, equipment efficiency levels, cost estimates, and equipment interactions,[1] and they are used to translate service demand into energy demand.

Appendixes A and B constitute one set of reports that characterizes most major residential equipment and commercial heating, cooling, and water heating equipment. Appendix A is used in developing Reference case projections, while Appendix B is used in developing advanced technology cases.[2] These assumptions will be developed and implemented during the AEO2024 cycle.

Appendixes C and D constitute another set of reports that characterizes residential and commercial lighting, as well as commercial ventilation and refrigeration equipment. Appendix C is used in developing the Reference case, while Appendix D is used in developing advanced technology cases. These assumptions were developed and implemented during the AEO2023 cycle.

When referencing the contracted reports in Appendixes A, B, C, and D, you should cite them as reports by Guidehouse and Leidos, prepared for the U.S. Energy Information Administration.

[1] Examples of equipment interactions are solar water heaters that supplement traditional water heaters, clothes washers that reduce the need for clothes drying, and water heaters that provide dishwashers and clothes washers with heated water.

[2] In addition to the Reference case, we also develop sensitivities to explore different assumptions for the cost and performance of future technologies. For the more optimistic cases, some equipment achieves lower life-cycle costs through improved efficiency or lower upfront costs, or both. The contracted reports provide a base case and an advanced case for modeling the AEO Reference case along with the more optimistic cases. We use the advanced case assumptions to develop side cases for AEO reports that include such analyses.

March 2023

APPENDIX A

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Final

EIA - Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case

Presented to:

U.S. Energy Information Administration

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March 3, 2023

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Objective

The objective of this study is to develop baseline and projected performance/cost characteristics for residential and commercial end-use equipment.

- Installed base in 2012 and 2018 (for commercial products) or 2015 and 2020 (for residential products) and current market (2022)
  - Review literature, standards, installed base, contractor, and manufacturer information
  - Provide a relative comparison and characterization of the cost/efficiency of a generic product
- Forecast of technology improvements that are projected to be available through 2050
  - Review trends in standards, product enhancements, and Research and Development (R&D)
  - Project impact of product improvements and enhancement to technology

The performance/cost characterization of end-use equipment developed in this study will assist EIA in projecting national primary energy consumption.

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Methodology

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Input from industry stakeholders, including government, R&D organizations, and manufacturers, was used to project product enhancements concerning equipment performance and cost attributes.

- Technology forecasting involves many uncertainties.
- Technology developments impact performance and cost forecasts.
- Varied sources ensure a balanced view of technology progress and the probable timing of commercial availability.
- Only currently published efficiency standards and regulations are considered when predicting technology developments; unpublished future regulatory action is not predicted.
- All costs are shown in 2022 dollars (2022$).
- Ranges, when given, represent the span of typical values for a given parameter (e.g., installed cost for equipment meeting the federal standard) not the highest and lowest available on the market.

Definitions

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The following tables represent the current and projected efficiencies for residential and commercial building equipment ranging from the installed base in 2012 and 2018 (for commercial products) or 2015 and 2020 (for residential products) to the highest efficiency equipment that is expected to be commercially available by 2050, assuming incremental adoption. Below are definitions for the terms used in characterizing the status of each technology.

- Installed Base: Efficiency values are for those units installed and "in use" in that year. Cost values are for the typical new unit sold in that year.
- Current Standard: The minimum efficiency (or maximum energy use) that is required (allowed) by current U.S. Department of Energy (DOE) standards, when applicable.
- ENERGY STAR: The minimum efficiency that is required (or maximum energy use allowed) to meet the ENERGY STAR criteria, when applicable. The performance data that are presented are representative of certified products that just meet current ENERGY STAR specifications.
- Typical: Efficiency and cost values are for the average, or "typical," product being sold in the particular timeframe. This may represent either the shipments-weighted average product performance or the most common product on the market.
- High: Efficiency and cost values are for the product with the highest efficiency available in the particular timeframe.

Market Transformation

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The market for the reviewed products has changed since this analysis was previously conducted.[1] These changes are noted and reflected in the efficiency and cost characteristics.

- In some categories the typical new product purchased today is more efficient than the average product in the installed base in 2012 (commercial) or 2015 (residential):
  - Residential sector: boilers, central air conditioners, room air conditioners, gas-fired furnaces (North), gas-fired furnaces (Rest of Country), oil-fired furnaces, electric resistance furnaces, heat pump water heaters, gas-fired instantaneous water heaters, natural gas cooktops, natural gas ovens, refrigerator-freezers, freezers, clothes dryers, clothes washers, and dishwashers
  - Commercial sector: gas-fired furnaces, oil-fired boilers, commercial rooftop heat pumps, commercial ground-source heat pumps, gas-fired instantaneous water heater, natural gas and electric ranges, griddles, and ovens
- More stringent Federal standards have taken effect for the following products:
  - Gas-fired and oil-fired boilers in 2021
  - Rooftop air conditioners and rooftop heat pumps in 2018
- Federal standards are slated to take effect in the coming years for the following products:
  - Central air conditioners, residential air-source heat pumps, gas-fired furnaces, oil-fired furnaces, gas-fired boilers, oil-fired boilers, rooftop air conditioners, and rooftop heat pumps in 2023
  - Portable air conditioners in 2025
- ENERGY STAR continues to raise the bar with revised criteria for:
  - Central air conditioners, residential air-source heat pumps, rooftop air conditioners, rooftop heat pumps, residential water heaters, and dishwashers in 2023

Note: The previous analysis is available in the EIA Technology Forecast Updates (2018) report.

Residential Space Heating and Cooling

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Residential Gas-Fired Furnaces (North)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (North) V. 4.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)[1]	80	80	80	80	80	80	80	80	80	80	80	80
AFUE (%)	80	80	80	90	95	99	95	99	95	99	95	99
Electric Consumption (kWh/y)[2]	374	374	386	636	631	725	631	725	631	725	631	725
Average Life (y)[3]	17	17	17	17	17	17	17	17	17	17	17	17
	26	26	26	26	26	26	26	26	26	26	26	26
Retail Equipment Cost (2022$)	1,300	1,300	1,080	1,200	1,220	1,390	1,220	1,390	1,220	1,390	1,220	1,390
Total Installed Cost (2022$)	2,880	2,880	3,690	4,130	4,150	4,320	4,150	4,320	4,150	4,320	4,150	4,320
Annual Maintenance Cost (2022$)	60	60	120	130	130	130	130	130	130	130	130	130

1. Typical input capacity is represented in terms of thousand British thermal units (kBtu) per hour (i.e., kBtu/h).
2. Electric consumption, represented in terms of kilowatt hours per year (kWh/y), accounts for the electricity consumption of components such as the furnace fan, draft inducer, and the ignitor. In some high efficiency products, this component also includes auxiliary equipment, such as condensate pumps and heat tape.
3. In the Residential Furnaces EERE 2022 Notice of Proposed Rulemaking (NOPR) Technical Support Document (TSD), an average lifetime of 22.5 years is calculated for gas-fired furnaces (North). Lifetime range was calculated using the Weibull Distribution in the Residential Furnaces EERE 2022 NOPR.

Note:
Models on the market can be either weatherized or non-weatherized. The majority (74%) are non-weatherized, and the values in the table use only non-weatherized data.
Electric consumption and cost values for 2022 and beyond are for a national sample and use the Residential Furnaces EERE 2022 NOPR Life-Cycle-Cost (LCC) spreadsheet.
Electric consumption and costs for the 2030, 2040, and 2050 high values are estimated based on the maximum-efficiency level analyzed in Residential Furnaces EERE 2022 NOPR, which is 98% annual fuel utilization efficiency (AFUE).
The current standard went into effect in November 2015.
ENERGY STAR V. 4.1 went into effect in February 2013.
The range for average life represents the span of typical values.

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Residential Gas-Fired Furnaces (Rest of Country)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (ROC) V. 4.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	80	80	80	80	80	80	80	80	80	80	80	80
AFUE (%)	80	80	80	90	90	99	95	99	95	99	95	99
Electric Consumption (kWh/y)[1]	279	279	386	636	636	725	631	725	631	725	631	725
Average Life (y)[2]	16	16	16	16	16	16	16	16	16	16	16	16
	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	1,260	1,260	1,080	1,200	1,200	1,390	1,220	1,390	1,220	1,390	1,220	1,390
Total Installed Cost (2022$)	2,380	2,380	3,690	4,130	4,130	4,320	4,150	4,320	4,150	4,320	4,150	4,320
Annual Maintenance Cost (2022$)	40	40	120	130	130	130	130	130	130	130	130	130

1. Electric consumption accounts for the electricity consumption of components such as the furnace fan, draft inducer, and the ignitor. In some high efficiency products, this component also includes auxiliary equipment, such as condensate pumps and heat tape.
2. In the Residential Furnaces EERE 2022 NOPR, an average lifetime of 21.5 years is calculated for gas-fired furnaces (Rest of Country). Lifetime range was calculated using the Weibull Distribution in the Residential Furnaces EERE 2022 NOPR.

Note:
Models on the market can be either weatherized or non-weatherized. The majority (74%) are non-weatherized, and the values in the table use only non-weatherized data.
Electric consumption and cost values for 2022 and beyond are for a national sample and use the Residential Furnaces EERE 2022 NOPR LCC spreadsheet.
Electric consumption and costs for the 2030, 2040, and 2050 high values are estimated based on the maximum-efficiency level analyzed in Residential Furnaces EERE 2022 NOPR, which is 98% AFUE.
The current standard went into effect in November 2015.
ENERGY STAR V. 4.1 went into effect in February 2013.
The range for average life represents the span of typical values.

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Residential Gas-Fired Furnaces

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- Current Federal standards for non-weatherized gas furnaces:
  - AFUE ≥ 80%
- ENERGY STAR V. 4.1 criteria for gas furnaces:
  - South: AFUE ≥ 90%
  - North: AFUE ≥ 95%
  - Furnaces must be equipped with electronically commutated fan motor and have less than or equal to 2.0% air leakage
- Most efficient unit currently available: 99.0% AFUE. The current market is nearly evenly split between non-condensing units (AFUE≤82%) and condensing units (AFUE≥90%).
- The maximum AFUE for non-condensing gas furnaces is 82%; above this level, the potential for exhaust gas condensation increases. This condensate is corrosive and requires cost restrictive corrosion resistant venting.
- High-efficiency condensing furnaces typically have high-grade stainless steel (AL 29-4C) heat exchangers.
- Many condensing furnaces are available as direct vent and sealed combustion systems, which do not use room air for combustion, but instead draw combustion air directly from outdoors.
- Depending on the location of the home, piping materials in use, and other considerations, condensing furnaces may need an acid neutralizer and/or lift pump for the condensate.
- Furnaces may contain permanent split capacitor (PSC) fan motors or electronically commutated motors (ECMs). The type of motor affects the electrical consumption of the furnace as well as the seasonal energy efficiency ratio (SEER) / energy efficiency ratio (EER) of the associated air conditioner.
  - The 2016 Energy Conservation Standards for Residential Furnace Fans Final Rule requires that all furnaces use ECM fans.
  - Most non-weatherized gas furnaces employ ECMs and can fully modulate rather than cycling on and off. Because they modulate, there is an increase in total fan-on time.

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Residential Gas-Fired Furnaces

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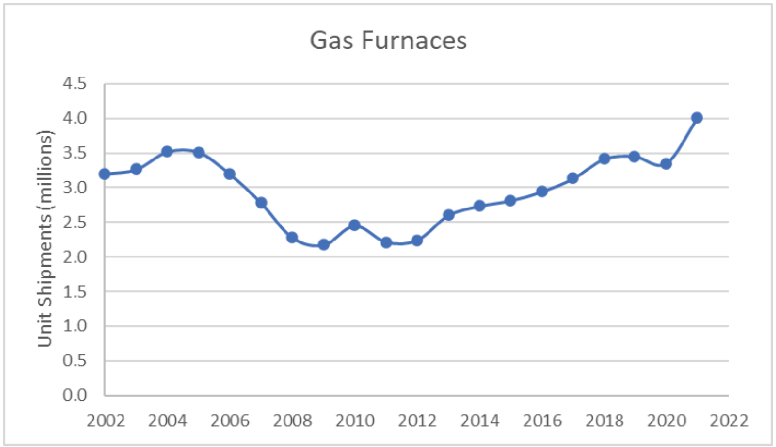
Annual shipments reached 3.5 million units in 2005 and then declined each year until 2009, leveling off at about 2.25 million units. Since 2012, shipments have increased steadily and reached a peak of 4.0 million units in 2021.



Source: *Air-Conditioning, Heating, and Refrigeration Institute (AHRI)*

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Residential Oil-Fired Furnaces

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	105	105	105	105	105	105	105	105	105	105	105	105
AFUE (%)	83	83	83	85	85	97	85	97	85	97	85	97
Electric Consumption (kWh/y)[1]	477	477	477	466	466	410	466	410	466	410	466	410
Average Life (y)[2]	20	20	20	20	20	20	20	20	20	20	20	20
	33	33	33	33	33	33	33	33	33	33	33	33
Retail Equipment Cost (2022$)	2,620	2,620	2,620	2,650	2,650	3,170	2,650	3,170	2,650	3,170	2,650	3,170
	3,450	3,450	3,450	3,490	3,490	4,090	3,490	4,090	3,490	4,090	3,490	4,090
Total Installed Cost (2022$)	3,250	3,250	3,250	3,480	3,480	5,140	3,480	5,140	3,480	5,140	3,480	5,140
	6,520	6,520	6,520	6,820	6,820	10,110	6,820	10,110	6,820	10,110	6,820	10,110
Annual Maintenance Cost (2022$)	80	80	80	80	80	240	80	240	80	240	80	240

1. Electric consumption accounts for the electricity consumption of components such as the furnace fan, draft inducer, and the ignitor. In some high efficiency products, this component also includes auxiliary equipment, such as condensate pumps and heat tape.
2. Lifetime range was calculated using the Weibull Distribution in Residential Furnaces EERE 2011.

Note:
The current standard went into effect in May 2013.
ENERGY STAR V. 4.1 went into effect in February 2013.
Ranges represent the span of typical values for a given parameter.

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Residential Oil-Fired Furnaces

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- Current Federal standards:
  - AFUE ≥ 83%
  - ≤ 11 watts of electrical power when in standby and off modes (non-weatherized models only)
- ENERGY STAR V. 4.1 criteria: AFUE ≥ 85%
- Since the latent heat content of oil is lower than that for either propane or natural gas, oil-fired appliances can typically operate at a higher AFUE rating than comparable gas-fired appliances before condensation issues arise.
- Most efficient unit currently available: 96.7% AFUE – condensing units with tiny market share (<1%), due to market acceptance issues.
- Condensate from condensing oil furnaces is typically even more corrosive than that of gas-fired systems due to the higher sulfur content in fuel oil. Hence, condensing oil furnaces also likely require the use of an acid neutralizer.
- Oil-fired furnaces, like gas-fired furnaces, achieve condensing conditions through the use of a secondary heat exchanger. Typically, these secondary heat exchangers use a high-grade stainless steel (AL 29-4C).
- Sooting is an issue for all oil-fired appliances, but secondary heat exchangers, with their narrow passages, are even more prone to be plugged by soot. Because of this, condensing oil furnaces typically require frequent cleaning and maintenance.

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Residential Oil-Fired Furnaces

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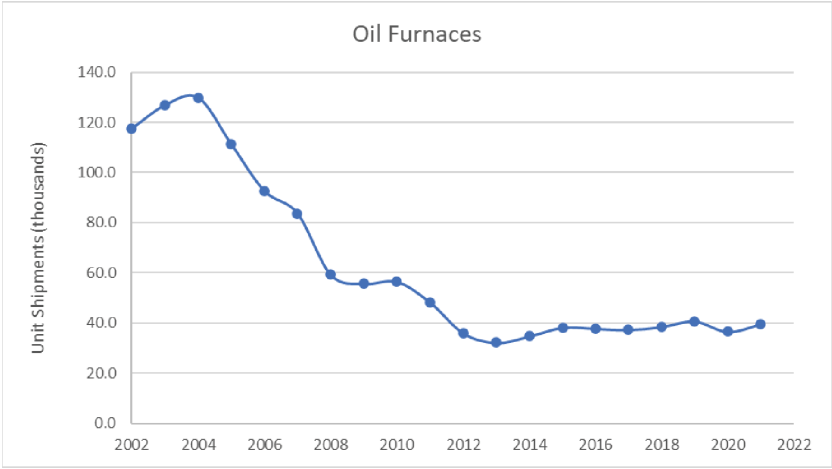
Annual shipments declined rapidly after 2004, likely due, at least in part, to an increase in fuel oil prices, which more than tripled from 2002 to 2008. Since 2012 shipments have largely leveled off.



Source: *AHRI*

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Residential Gas-Fired Boilers

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DATA	2015	2020[1]	2022				2030[2]		2040[2]		2050[2]	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	100	100	100	100	100	100	100	100	100	100	100	100
AFUE (%)	82	95	84	95	90	96	95	96	95	96	95	96
Electric Consumption (kWh/y)[3]	197	506	282	506	527	502	506	502	506	502	506	502
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20	20
	30	30	30	30	30	30	30	30	30	30	30	30
Retail Equipment Cost (2022$)	2,540	2,890	1,820	2,890	2,440	3,670	2,890	3,670	2,890	3,670	2,890	3,670
Total Installed Cost (2022$)	7,760	5,940	8,700	5,940	6,700	6,710	5,940	6,710	5,940	6,710	5,940	6,710
Annual Maintenance Cost (2022$)[4]	110	160	150	160	160	160	160	160	160	160	160	160

1. The 2020 AFUE is estimated based on EERE 2022 preliminary analysis, which estimates that gas-fired boilers with the highest market share in 2020 have an AFUE of 95%.
2. The 2030, 2040, 2050 projections are estimated based on the EERE 2022 preliminary analysis, which notes that majority of the market is expected to be condensing, if new standards are not implemented. The EERE 2022 preliminary analysis estimates a minimum efficiency of 95% AFUE for condensing units.
3. Electric Consumption accounts for the electricity consumption of auxiliary electrical components including circulating pump, the boiler pump (condensing boilers only), the draft inducer (if present), and the ignitor. It also accounts for the electricity consumption of auxiliary equipment such as a condensate pump and heat tape, which are sometimes installed with higher efficiency boilers. Additionally, it accounts for the additional cooling load due to heat loss from the boiler and water heater as a result of water heating during the cooling season.
4. Maintenance cost is the routine annual cost to the consumer of general maintenance for product operation. Maintenance cost is higher for condensing boilers for the inspection of condensate system and replacement of condensate neutralizer filter.

Note:
The current standard went into effect in January 2021.
ENERGY STAR V. 3.0 went into effect in December 2013.
Water boilers considered. Steam boilers also exist but make up a small percentage of the market.
The range for average life represents the span of typical values.

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Residential Gas-Fired Boilers

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- Federal standard for gas-fired hot-water boilers (more common than steam):
  - AFUE ≥ 84%
  - Standard went into effect on January 21, 2021
- ENERGY STAR criteria: AFUE ≥ 90%
- Most efficient gas-fired boiler available: 96.4% AFUE
- Gas-fired boilers have lost market share to furnaces and heat pumps over the past 30 years.
- U.S. gas hot water boiler sales are split approximately 60/40 between condensing and non-condensing.[1] Condensing boilers typically have heat exchangers made of stainless steel, and non-condensing boilers typically have heat exchangers made of cast iron.
- Typically, condensing boilers are low-mass in construction with modulating burners, variable-speed inducer fan systems or sealed powered direct-vent combustion, multiple sensor technologies, and electronic ignition and control.
- Due to incentives and market pressure, the U.S. boiler industry has been shifting towards also providing condensing boilers. Most of these boilers are private-labeled products sourced from Europe, where the hydronic market is much bigger and condensing appliances are much more common and/or required by law.
- Most value-added components for condensing boilers are sourced abroad, even when the condensing boiler is assembled in North America (e.g., heat exchanger, gas valve, burner, sensors, and/or controls).

Source: EERE 2022 Preliminary Analysis TSD, Chapter 3

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Residential Gas-Fired Boilers

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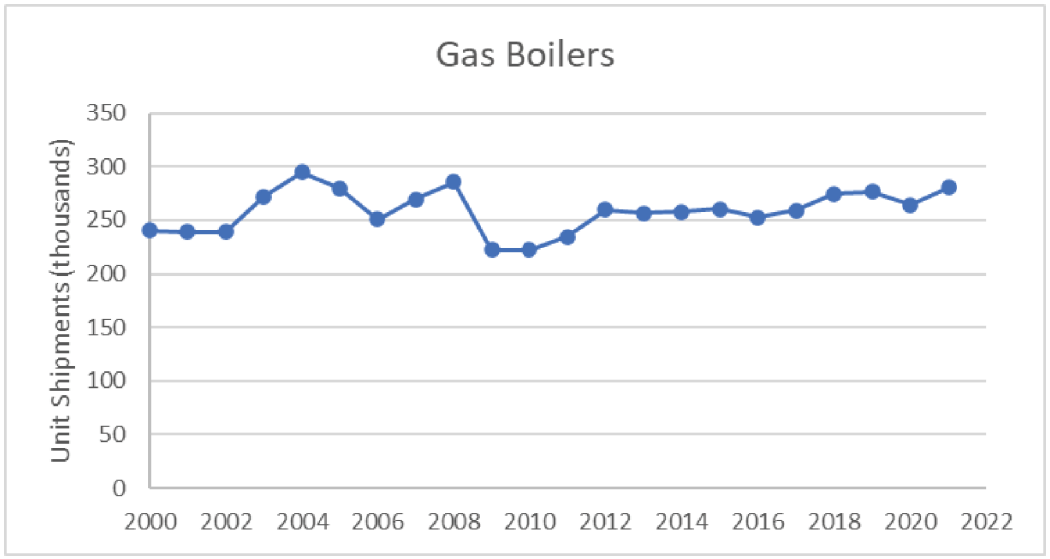
Annual shipments had a significant decrease following the 2009 financial crisis and a steady recovery in the years since.



Source: *Boilers EERE 2022 Preliminary Analysis*

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DATA	2015	2020[1]	2022				2030[2]		2040[2]		2050[2]	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	140	140	140	140	140	140	140	140	140	140	140	140
AFUE (%)	84	86	86	86	87	88	86	88	86	88	86	88
Electric Consumption (kWh/y)[3]	230	310	310	310	307	305	310	305	310	305	310	305
Average Life (y)[4]	18	18	18	18	18	18	18	18	18	18	18	18
	28	28	28	28	28	28	28	28	28	28	28	28
Retail Equipment Cost (2022$)	4,850	3,590	3,590	3,590	3,680	3,770	3,590	3,770	3,590	3,770	3,590	3,770
Total Installed Cost (2022$)	9,800	5,510	5,510	5,510	5,600	5,690	5,510	5,690	5,510	5,690	5,510	5,690
Annual Maintenance Cost (2022$)[4]	160	170	170	170	170	170	170	170	170	170	170	170

1. The 2020 AFUE is estimated based on EERE 2022 preliminary analysis, which estimates that oil-fired boilers with the highest market share in 2020 have an AFUE of 86%.
2. The 2030, 2040, 2050 projections are estimated based on the EERE 2022 preliminary analysis, which notes that majority of the market is expected to be at 86% AFUE, if new standards are not implemented.
3. Electric Consumption accounts for the electricity consumption of auxiliary electrical components including circulating pump, the ignitor, condensate pump, and heat tape, which are sometimes installed with higher efficiency boilers. Additionally, it accounts for the additional cooling load due to heat loss from the boiler and water heater as a result of water heating during the cooling season.
4. Maintenance cost is the routine annual cost to the consumer of general maintenance for product operation.

Note:
The current standard went into effect in January 2021.
ENERGY STAR V. 3.0 went into effect in December 2013.
Water boilers considered. Steam boilers also exist but make up a small percentage of the market.
The range for average life represents the span of typical values.

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- Federal standard for oil-fired hot-water boilers (more common than steam):
  - AFUE ≥ 86%
  - Standard went into effect on January 21, 2021
- ENERGY STAR criteria: AFUE ≥ 87%
- Most efficient oil-fired boiler available: 88% AFUE
- Since the latent heat content of oil is lower than that for either propane or natural gas, oil-fired appliances can typically operate at a higher AFUE rating than comparable gas-fired appliances before condensation issues arise.
- Oil boilers have heat exchangers made of cast iron or steel.
- No condensing oil-fired boilers currently exist in the U.S. market. The high sulfur content in fuel-oil causes heat exchanger fouling if the flue gases from an oil-fired boiler were to condense. As a result, condensing oil-fired boilers would require more frequent maintenance and repair, if installed.

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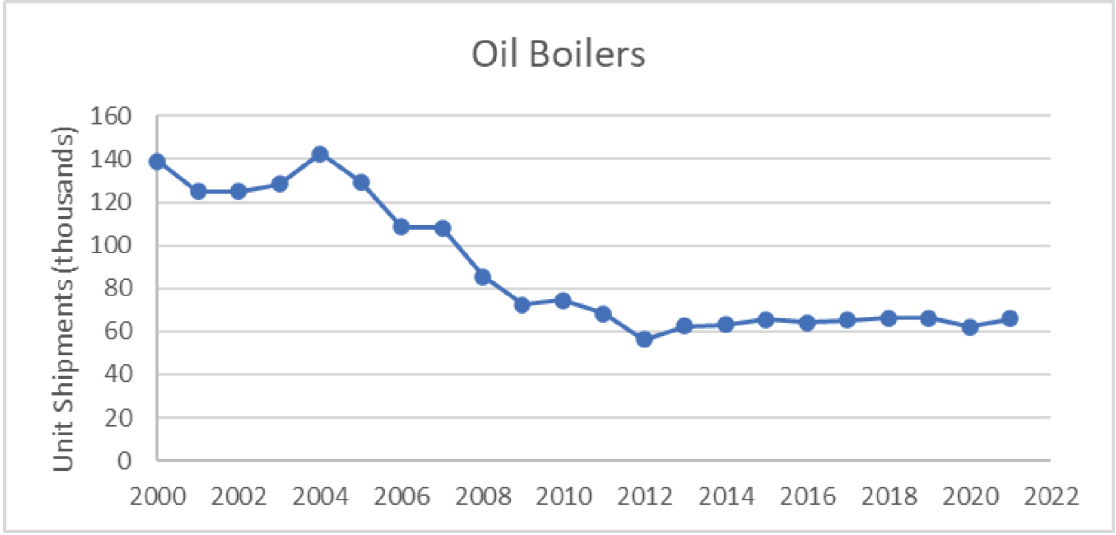
Annual shipments declined rapidly after 2004, likely due, at least in part, to an increase in fuel oil prices, which more than tripled from 2002 to 2008. Since 2012 shipments have largely leveled off.



Source: *Boilers EERE 2022 Preliminary Analysis*

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Residential Electric Resistance Furnaces

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DATA	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Input Capacity (kBtu/h)	68	68	68	68	68	68	68
AFUE (%)	98	98	100	100	100	100	100
Average Life (y)	15	15	15	15	15	15	15
	30	30	30	30	30	30	30
Retail Equipment Cost (2022$)[1]	760	760	950	950	950	950	950
Total Installed Cost (2022$)[1]	1,290	1,290	1,480	1,480	1.480	1,480	1,480
Annual Maintenance Cost (2022$)[1]	50	50	50	50	50	50	50

1. Costs for a 100% AFUE unit are assumed to be equal to the costs of a 98% AFUE unit.

Note:
The current standard went into effect in January 1992.
The range for average life represents the span of typical values.

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Residential Electric Resistance Furnaces

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- Federal standards for electric furnaces:
  - AFUE ≥ 78%
  - Standby and off mode power consumption ≤ 10 watts
- According to preliminary Residential Energy Consumption Survey (RECS) data released May 2022, electric central warm-air furnaces are the main source of space heating in approximately 17.5 million U.S. homes or about 14%.
- Electric furnaces range in capacity from 10 to 25 kW (34 to 85 kBtu/h), with 20 kW (68 kBtu/h) being the typical for units on the market.
- Electric resistance furnaces are considered near 100% efficient because there is no flue heat loss, and any jacket losses are contained within the home.
  - ASHRAE Standard 103, the test method for furnaces incorporated by reference into the federal test procedure, specifies that for electric furnaces AFUE = 100 – 1.7 x jacket losses. Jacket losses can be determined either through testing or assumed to be 1%. Thus, the minimum AFUE of electric furnaces is 98.3%.

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Residential Electric Resistance Unit Heaters

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DATA	2015	2020	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (kBtu/h)	3.5	3.5	5.1	5.1	5.1	5.1
Efficiency (%)	100	100	100	100	100	100
Average Life (y)[1]	15	15	15	15	15	15
	30	30	30	30	30	30
Retail Equipment Cost (2022$)[2]	90	90	85	85	85	85
	240	240	340	340	340	340
Total Installed Cost (2022$)[3]	150	150	390	390	390	390
	320	320	1,190	1,190	1,190	1,190
Annual Maintenance Cost (2022$)[4]	-	-	-	-	-	-

1. Assumes similar lifetime to Electric Furnaces on the basis that both products have heating elements that burn out and lead to product failure.
2. The lower bound of the equipment costs represents the average retail price listed at the typical capacity for electric baseboard heaters through a retailer website. The upper bound represents the average retail price for compact recessed electric wall heaters at the same capacity.
3. Range represents the estimated minimum and maximum installation costs.
4. Maintenance costs are negligible.

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Residential Electric Resistance Unit Heaters

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- Electric resistance unit heaters include electric wall and baseboard heaters. Plug-in space heaters are not included.
- There are currently no federal efficiency requirements for electric resistance unit heaters.
- According to preliminary RECS data released May 2022, electric resistance unit heaters are the main source of space heating in approximately 8.25 million U.S. homes or about 7%.
- Electric heaters range in capacity from 500 to 2,500 watts (1.7 to 8.5 kBtu/h), with 1,500 watts (5.1 kBtu/h) being the most typical for units on the market.
- Electric resistance heating is considered 100% energy efficient; all incoming electric energy is converted to heat.

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Residential Central Air Conditioners – North (Not Hot-Dry or Hot-Humid)

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DATA	2015	2020	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
SEER[1]	12.5	13.9	13.0	14.1	15.0	17.0	14.1	16.0	17.0	14.4	17.0	14.4	17.0	14.4	17.0
SEER2[2]	11.9	13.2	NA	13.4	NA	16.2	13.4	15.2	16.2	13.7	16.2	13.7	16.2	13.7	16.2
Average Life (y)	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	2,410	2,670	2,580	2,700	3,110	3,950	2,680	3,750	3,950	2,760	3,950	2,760	3,950	2,760	3,950
Total Installed Cost (2022$)	4,000	4,300	5,250	5,320	5,520	5,980	5,310	5,880	5,980	5,350	5,980	5,350	5,980	5,350	5,980
Annual Maintenance Cost (2022$)[3]	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150

1. Values shown are for split-system units in the 36 kBtu/h (3-ton) size class. Costs and efficiency levels are for "coil-only" systems, meaning they do not include a blower. Note blower-coil systems were analyzed for residential air-source heat pumps, which is why the "High" SEER levels are higher for heat pumps than for air conditioners.
2. In 2023, new energy conservation standards for Residential Central Air Conditioners and Heat Pumps took effect. The new standards specify a different metric for central air conditioners (SEER2). SEER to SEER2 conversions were determined using the RESNET website.
3. Annual maintenance include preventative maintenance and services provided by HVAC professionals for maintaining product operation. Examples include, calibrate and level thermostat, clean filters, clean indoor and condenser coil, flush/treat condensate drain with anti-algae, inspect condenser coil, monitor operating pressure of refrigerant, inspect fan blade, etc.

Note:
The previous standard went into effect in January 2015. The current standard went into effect in January 2023.
ENERGY STAR V. 5.0 went into effect in September 2015. ENERGY STAR V. 6.1 went into effect in January 2023.
Ranges represent the span of typical values for a given parameter.

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Residential Central Air Conditioners – South (Hot-Dry and Hot-Humid)

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DATA	2015	2020	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
SEER[1]	13.0	14.4	14.0	14.6	15.0	17.0	15.1	16.0	17.0	15.1	17.0	15.1	17.0	15.1	17.0
SEER2[2]	12.4	13.7	NA	13.9	NA	16.2	14.3	15.2	16.2	14.3	16.2	14.3	16.2	14.3	16.2
Average Life (y)	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	2,410	2,760	2,680	2,850	3,110	3,950	3,110	3,750	3,950	3,190	3,950	3,190	3,950	3,190	3,950
Total Installed Cost (2022$)	4,000	4,390	5,310	5,390	5,520	5,980	5,520	5,880	5,980	5,570	5,980	5,570	5,980	5,570	5,980
Annual Maintenance Cost (2022$)	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150

1. Values shown are for split-system units in the 36 kBtu/h (3-ton) size class. Costs and efficiency levels are for "coil-only" systems, meaning they do not include a blower. Note blower-coil systems were analyzed for residential air-source heat pumps, which is why the "High" SEER levels are higher for heat pumps than for air conditioners.
2. In 2023, new energy conservation standards for Residential Central Air Conditioners and Heat Pumps took effect. The new standards specify a different metric for central air conditioners (SEER2). SEER to SEER2 conversions were determined using the RESNET website.
3. Annual maintenance include preventative maintenance and services provided by HVAC professionals for maintaining product operation. Examples include, calibrate and level thermostat, clean filters, clean indoor and condenser coil, flush/treat condensate drain with anti-algae, inspect condenser coil, monitor operating pressure of refrigerant, inspect fan blade, etc.

Note:
The previous standard went into effect in January 2015. The current standard went into effect in January 2023.
ENERGY STAR V. 5.0 went into effect in September 2015. ENERGY STAR V. 6.1 went into effect in January 2023.
Ranges represent the span of typical values for a given parameter.

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- The previous standards took effect in 2015; amended standards for all product classes went into effect in January 2023.
  - Amended standards are based on new metrics (SEER2, EER2).
  - SEER2 values are generally expected to be lower than SEER because a higher external static pressure is required during testing, which reduces measured performance.
- Systems installed in the Southwest (CA, AZ, NM, and NV) must also meet an EER standard that varies by cooling capacity and system configuration.

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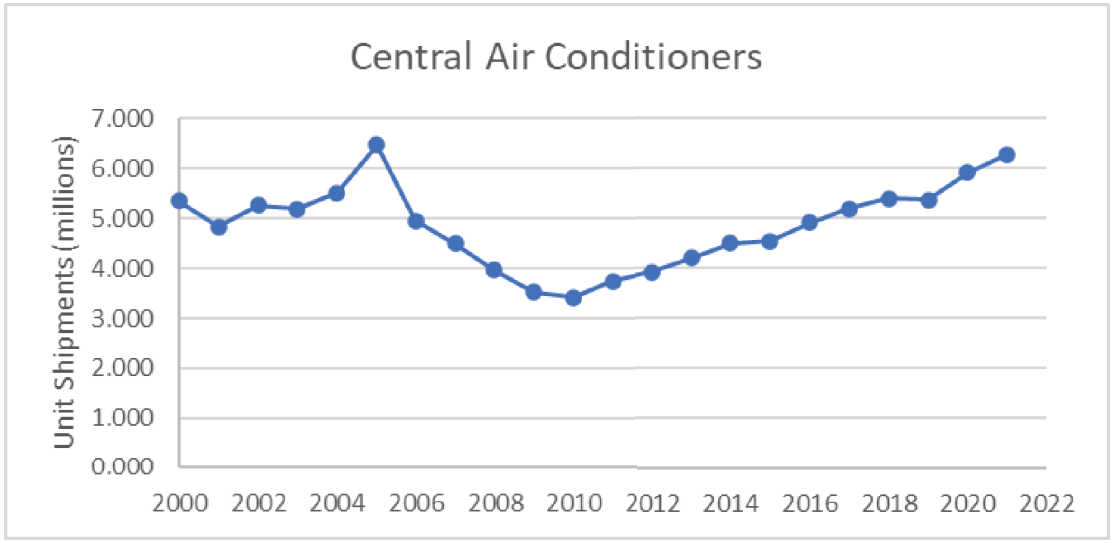
Annual shipments spiked at 6.5 million units in 2005 at the peak of the housing boom and just before more stringent Federal standards took effect in 2006. Annual shipments have been steadily increasing since 2010 and have almost reached the previous high in 2021.



Source: *AHRI*

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Residential Room Air Conditioners

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DATA	2015	2020	2022				2030[2]		2040[2]		2050[2]	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.2	High[1]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	10	10	10	10	10	10	10	10	10	10	10.0	10.0
CEER (Btu/Wh)	10.9	10.9	10.9	12.0	12.0	15.7	12.0	15.7	12.0	15.7	12.0	15.7
Average Life (y)	6	6	6	6	6	6	6	6	6	6	6	6
	13	13	13	13	13	13	13	13	13	13	13	13
Retail Equipment Cost (2022$)	560	330	330	340	340	450	340	450	340	450	340	450
	710	480	480	480	480	590	480	590	480	590	480	590
Total Installed Cost (2022$)	640	490	490	490	490	600	490	600	490	600	490	600
	830	630	630	640	640	750	640	750	640	750	640	750
Annual Maintenance Cost (2022$)[3]	0	0	0	0	0	0	0	0	0	0	0	0

1. RAC EERE 2022 NOPR has analysis for combined energy efficiency ratio (CEER) of 16 Btu/Wh, which represents variable speed room air conditioners. However, maximum CEER identified in DOE's Compliance Certification Database (CCD) in August 2022 was 15.7 Btu/Wh. Accordingly, the high CEER is estimated to be 15.7 for 2022 and beyond. Cost values for a representative unit with a CEER of 16 Btu/Wh were used.
2. The 2030, 2040, 2050 projections are estimated based on RAC EERE 2022 NOPR, which notes that in the absence of no new standards, room air conditioners with a CEER of 12 Btu/Wh are expected to have the maximum market share.
3. Maintenance costs are negligible per RAC EERE 2011 and RAC EERE 2022 NOPR.

Note:
All values are for the most common product class, Product Class 3 (without reverse cycle, with louvered sides, and 8,000 to 13,999 Btu/h).
The current standard went into effect in June 2014.
ENERGY STAR V. 4.2 went into effect in October 2015.
Ranges represent the span of typical values for a given parameter (for example, installed cost for equipment meeting the federal standard) not the highest and lowest available on the market.

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Residential Room Air Conditioners

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- Analyzed the most common type of room air conditioners: louvered sides (window air conditioners) without reverse cycle and having cooling capacity of 8,000–13,999 Btu/h (DOE Product Class 3).
- Federal standards for Product Class 3:
  - CEER ≥ 10.9 (beginning June 1, 2014)
- CEER incorporates energy use in cooling mode and standby and off modes.
- ENERGY STAR V. 4.2 criteria for Product Class 3:
  - CEER ≥ 12.0 (effective October 26, 2015)
- Efficiency improvements in room air conditioners are attained by:
  - Higher efficiency compressor and fan motors (including variable speed motors), and
  - An increased heat transfer area in the evaporator and condenser using larger heat exchangers, finer fin spacing, micro-channel heat exchangers, and similar design options.

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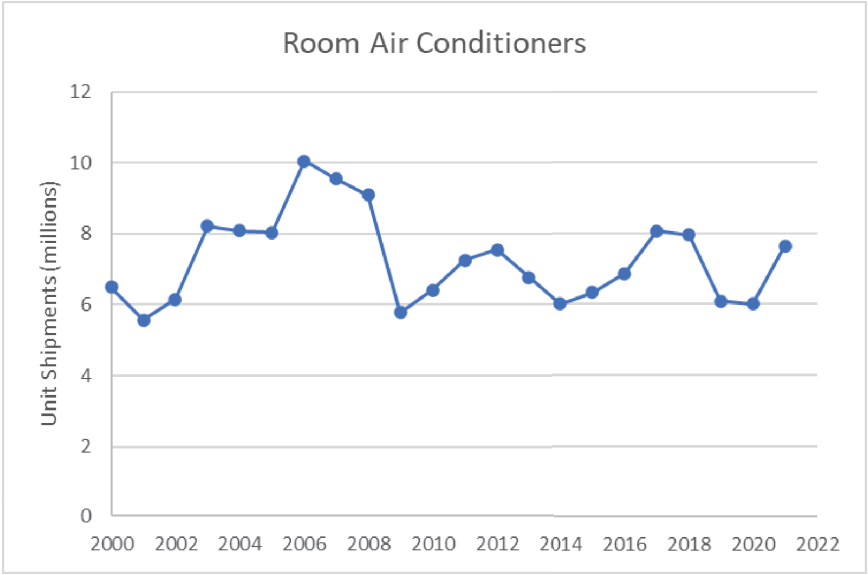
Annual shipments dropped sharply in 2009, likely due to the recession and an unusually cool summer in the Northeast. Sales have largely leveled off in the years since, fluctuating between 6 and 8 million.



Source: *RAC EERE 2022 NOPR*

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Residential Portable Air Conditioners

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DATA	2015	2020	2022[4]		2025		2030		2040		2050	
	Installed Base	Installed Base	Typical	High[5]	New Standard	High[5]	Typical	High[5]	Typical	High[5]	Typical	High[5]
Typical Capacity (kBtu/h)[1]	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
CEER[2]	5.6	5.6	5.5	7.6	6.7	7.6	6.7	7.6	6.7	7.6	6.7	7.6
Average Life (y)	7	7	7	7	7	7	7	7	7	7	7	7
	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)	700	700	700	810	760	810	760	810	760	810	760	810
Total Installed Cost (2022$)[3]	700	700	700	810	760	810	760	810	760	810	760	810
Annual Maintenance Cost (2022$)[3]	0	0	0	0	0	0	0	0	0	0	0	0

1. All values are for the average capacity for single-duct and dual-duct portable air conditioners available on the market.
2. CEER is calculated for typical capacity using the equation provided in PAC EERE 2020.
3. Installation and maintenance costs are negligible.
4. The 2022 Typical estimates are based on PAC EERE 2020, which estimated majority of the market to be at EL1 in 2022 for the no-new standards case, which translates to a CEER of 5.5 for this analysis.
5. All High values are based on the most-efficient models available in the market, as specified in PAC EERE 2020.

Note:
A final rule for portable air cleaners published in January 2020 with an effective date of January 2025.
Costs are interpolated from the costs presented in PAC EERE 2020.
Range for lifetime represents typical values.

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Residential Portable Air Conditioners

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- A final rule establishing new energy conservation standards for portable air conditioners published in January 2020 with an effective date of January 2025.
- The final rule outlined an equation-based conservation standard (in CEER) for both single-duct and dual-duct portable ACs, based on the seasonally adjusted cooling capacity (SACC)

$$\text{Minimum CEER} = \text{PR} \times \frac{\text{SACC}}{(3.7117 \times \text{SACC}^{0.6384})}$$

- Efficiency improvements in portable air conditioners are attained by:
  - Higher efficiency compressor and fan motors (including variable speed motors), and
  - An increased heat transfer area in the evaporator and condenser using larger heat exchangers, finer fin spacing, micro-channel heat exchangers, and similar design options.

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Residential Portable Air Conditioners

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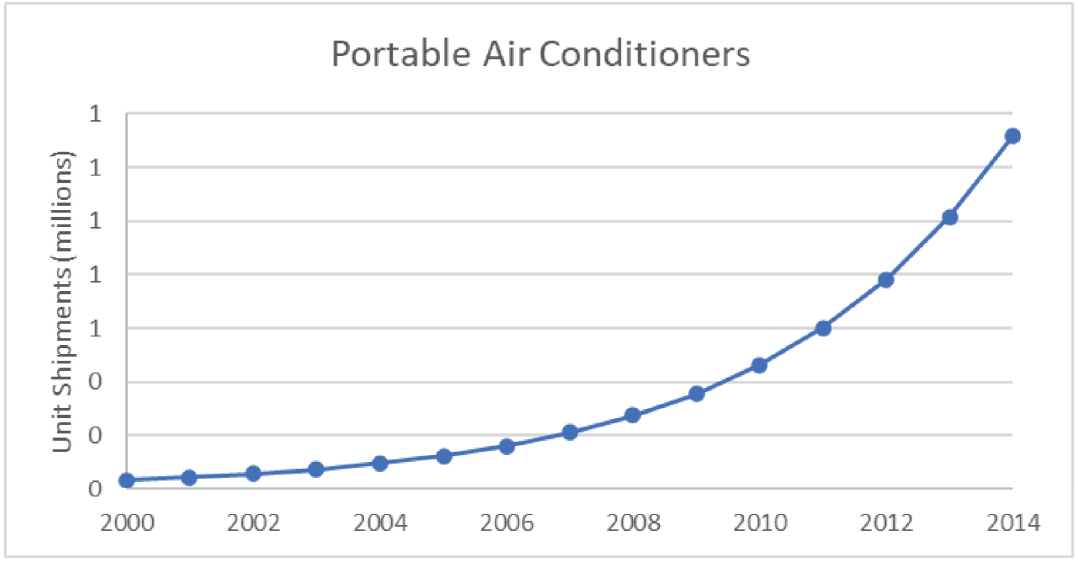
Annual shipments have seen an exponential growth through 2014. Shipments data since 2014 is not publicly available but it is expected that portable air conditioners shipments may have increased in recent years in response to indoor air quality concerns following COVID-19.



Source: *PAC EERE 2020*

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Residential Swamp Coolers

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Air Flow Rate (CFM)	3,800	3,800	3,800	4,700	3,800	4,700	3,800	4,700	3,800	4,700
Power (Hp)	1/3	1/3	1/3	1/2	1/3	1/2	1/3	1/2	1/3	1/2
Average Life (y)[1]	10	10	10	10	10	10	10	10	10	10
	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)	960	960	960	1,100	960	1,100	960	1,100	960	1,100
Total Installed Cost (2022$)	1,360	1,360	1,360	1,540	1,360	1,540	1,360	1,540	1,360	1,540
Annual Maintenance Cost (2022$)	330	330	330	330	330	330	330	330	330	330

1. Average lifetime provided by major swamp cooler installer in the U.S. Southwest.

Note:
Efficiency values were determined based on a sample of window-mounted swamp coolers.
Lifetime range represents span of typical values.

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Residential Swamp Coolers

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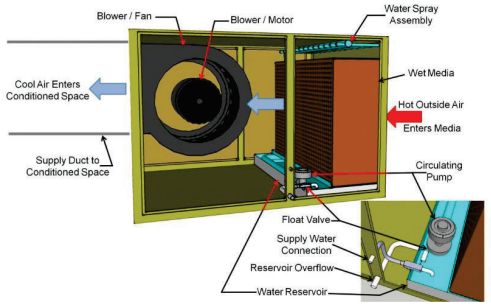
- Evaporative cooling (i.e., "swamp coolers") is a technology that takes advantage of water evaporation to cool incoming air. Energy is required to change water from a liquid to a vapor (i.e., the heat of vaporization), and in doing so, temperature of the air is reduced. Evaporative cooling is best suited for hot, dry climates.
- Swamp coolers come in a variety of different configurations, including centrally ducted units that are mounted outside a building or roof; window evaporative coolers that are window-mount units that pull in warm outdoor air, pass it through wet media to remove heat, and blow out the cooled air; or portable plug-in units. Window units were considered for this analysis due to the high model share count on distributor websites.
- The U.S. Environmental Protection Agency (EPA) has cautioned against using swamp coolers in wildfire-impacted areas in smoky conditions because it can result in more smoke bring brought inside.
- Swamp coolers are not a DOE-covered product.
- Swamp cooler metrics include power of the fan/blower, measured in horsepower (hp), and air flow rate, measured in cubic feet per minute (CFM).



Single-inlet direct swamp cooler. Source: PNNL

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Residential Air-Source Heat Pumps

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DATA	2015	2020	2022				2023				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	ENERGY STAR Cold Climate Criteria	High[4]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
SEER (Cooling)[1]	13.1	15.3	14.0	15.3	15.0	22.6	15.0	16.0	NA	22.6	16.0	22.6	16.5	22.6	17.0	22.6
SEER2[2]	12.4	14.5	NA	14.5	NA	21.5	14.3	15.2	15.2	21.5	15.2	21.5	15.7	21.5	16.2	21.5
HSPF (Heating)[1]	7.9	8.6	8.2	8.6	8.5	12.4	8.8	9.2	NA	12.4	9.2	12.4	9.3	12.4	9.3	12.4
HSPF2[2]	6.7	7.3	NA	7.3	NA	10.6	7.5	7.8	8.1	10.6	7.8	10.6	7.9	10.6	7.9	10.6
Average Life (y)	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
Retail Equipment Cost (2022$)[1]	3,290	4,270	3,970	4,270	4,110	6,740	4,110	4,380	4,380	6,740	4,380	6,740	5,000	6,740	5,100	6,740
Total Installed Cost (2022$)[1]	5,790	6,880	6,730	6,880	6,810	8,620	6,810	6,940	6,940	8,620	6,940	8,620	7,240	8,620	7,330	8,620
Annual Maintenance Cost (2022$)[3]	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150

1. Values shown are for split-system units in the 36 kBtu/h (3-ton) size class. Costs and efficiency levels are for "blower-coil" systems, meaning they include a blower. Note coil-only systems were analyzed for residential central air conditioners, which is why the "High" SEER levels are higher for heat pumps than for air conditioners.
2. In 2023, new energy conservation standards for Residential Central Air Conditioners and Heat Pumps took effect. The new standards specify different metrics for Air-Source Heat Pumps (SEER2 and heating seasonal performance factor 2 (HSPF2)). SEER to SEER2 and HSPF to HSPF2 conversions were determined using the RESNET website.
3. Annual maintenance include preventative maintenance and services provided by HVAC professionals for maintaining product operation. Examples include, calibrate and level thermostat, clean filters, clean indoor and condenser coil, flush/treat condensate drain with anti-algae, inspect condenser coil, monitor operating pressure of refrigerant, inspect fan blade, etc.
4. High costs derived from developing a cost-efficiency curve between retail/installed costs and SEER.

Note:
The previous standard went into effect in January 2015. The current standard went into effect in January 2023.
ENERGY STAR V. 5.0 went into effect in September 2015. ENERGY STAR V. 6.1 went into effect in January 2023.
Ranges represent the span of typical values for maintenance costs.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.88, 2, 1).

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Residential Air-Source Heat Pumps

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- The previous standards took effect in 2015; amended standards for all product classes went into effect in January 2023.
  - Amended standards are based on new metrics (SEER2, EER2, HSPF2).
  - SEER2 values are generally expected to be lower than SEER because a higher external static pressure is required during testing, which reduces measured performance.
- High efficiency cooling does not necessarily correlate with high efficiency heating. The range of SEER–HSPF combinations is very broad.
- Heat pumps are generally sized to meet the cooling load of the house. When the heating load exceeds heat pump heating capacity, electric resistance heat is used to supplement.
- Variable-speed compressors improve efficiency of heat pumps by reducing cyclic losses and by operating above their nominal speed, boosting heating capacity, and reducing the need for supplementary electric resistance heat.
- In addition to meeting the SEER2 and HSPF2 requirements, air source heat pumps must demonstrate low ambient performance to earn the Cold Climate designation by meeting the following:
  - Coefficient of Performance (COP) at 5 degrees Fahrenheit (°F) ≥ 1.75, measured in accordance with Appendix M1 $H4_2$ test
  - Percent of Heating Capacity at 5 °F ≥ 70% of that at 47 °F, with the 5 °F capacity measured per Appendix M1 $H4_2$ test and the 47 °F capacity measured as the nominal heating capacity per Appendix M1 (i.e., from the Appendix M1 $H1_N$ test for units having a variable-speed compressor where the compressor speed shall be the maximum speed that the system controls would operate at 47 °F, otherwise from the Appendix M1 $H1_2$ test)
  - Perform a controls verification procedure (CVP) to confirm that the above performance metrics measured at the Appendix M1 low ambient test point at 5 °F are achieved by the native controls operating as they would in a customer's home

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Residential Air-Source Heat Pumps

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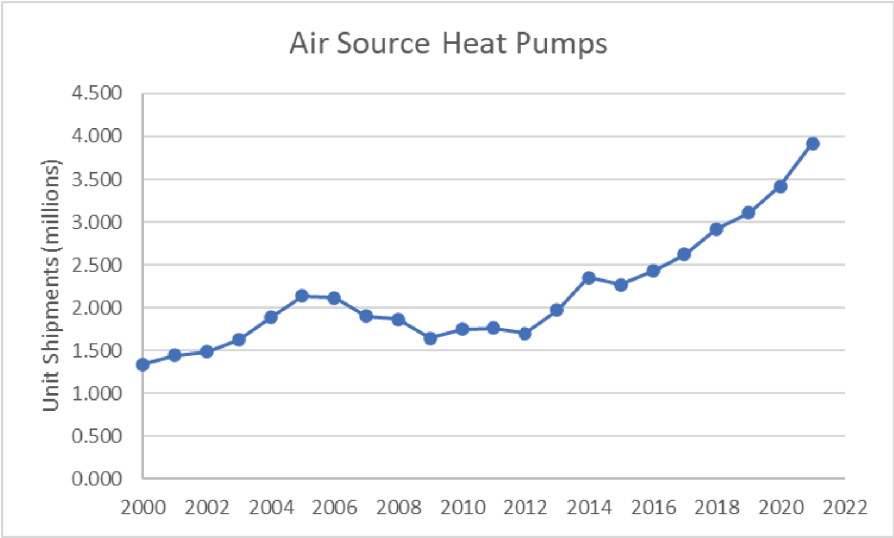
From 2000 to 2005 annual shipments increased nearly 60% to 2.1 million units, then dropped and leveled off around 1.7 million units. In 2014 annual shipments surpassed the 2005 peak and have been increasing uniformly since then.



Source: *AHRI*

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Residential Central Air Conditioners and Air-Source Heat Pumps

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- Principal energy efficiency drivers for central air conditioners and heat pumps:
  - Heat exchanger (surface area, number of tube rows)
  - Compressor (type and single-stage vs. two-stage vs. variable-speed operation)
  - Fan motor choices (PSC vs. ECM fan motors on inside and outside)
  - Control choices (i.e., piston, thermal, and electronic expansion valves)
- When the heat pump or air conditioner's capacity exceeds the heating or cooling load, the unit starts and stops more frequently, causing wear and tear on the components and an overall loss of efficiency. Multi-stage and/or variable-speed compressors can help, as does sophisticated refrigerant management.
- Typical high-efficiency unit (≥ 16 SEER) has very large heat exchanger, ECM evaporator fan motor, and two-stage scroll compressor.
- Variable-speed compressor technology typically leads to a significant SEER boost, making possible high-SEER condensing units with smaller heat exchangers, and thus, smaller enclosures.
- Efficiency levels > 21 SEER made possible through combining existing large heat exchangers with variable-speed compressors, ECM fan motors, and electronic expansion valves.

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Residential Ductless Mini-Split Air-Source Heat Pumps

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)[1]	12	12	12	12	12	12	12	12	12	12
SEER	16.0	16.0	21.9	33.1	21.9	33.1	21.9	33.1	21.9	33.1
EER	12.5	12.5	13.0	19.1	13.0	19.1	13.0	19.1	13.0	19.1
HSPF	10.0	10.0	11.1	14.0	11.1	14.0	11.1	14.0	11.1	14.0
Average Life (y)[2]	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
Retail Equipment Cost (2022$)	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580
Total Installed Cost (2022$)	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030
Annual Maintenance Cost (2022$)[3]	100	100	100	100	100	100	100	100	100	100

1. Representative capacity determined from most frequent capacity in AHRI database
2. Assumed same lifespan and maintenance cost as air-source heat pumps given the technology is similar between air-source and ductless mini-split heat pumps, and ductwork itself is not expected to fail.
3. Annual maintenance covers the same services identified for air-source heat pumps.

Note:
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.88, 2, 1).

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Residential Ductless Mini-Split Air-Source Heat Pumps

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- Ductless systems can be useful in "spot cooling" certain high-use areas of a home, such as a living room, bedroom, or office.
- Mini-split heat pumps are generally more efficient (often > 20 SEER) and smaller in cooling capacity (often ≤ 24 kBtu/h) compared to split-system heat pumps.
  - A mini-split heat pump could be equal in capacity and efficiency to a split-system heat pump as there are no inherent design changes between split-system and mini-split heat pumps, aside from the ductwork. Mini-split heat pumps tend to be more efficient and smaller in capacity due to their prevalence for spot cooling, but the same technologies are used between the two product categories.
- Due to the similarities in design, cost estimations were determined based on smaller capacity (24 kBtu/h) split-system heat pumps and Gordian's RSMeans Data – Building Construction Costs 2023. Efficiency data was analyzed using the AHRI directory, which provides disaggregation of data on the basis of ducted and ductless heat pumps.
- Annual maintenance covers the same services identified for air-source heat pumps.

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Residential Ground-Source Heat Pumps

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.2	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36
COP (Heating)[1]	3.1	3.7	3.2	3.6	3.6	4.5	3.6	4.5	3.6	4.5	3.6	4.5
EER (Cooling)[2]	13.3	17.3	14.1	17.3	17.1	22.0	17.3	22.0	17.3	22.0	17.3	22.0
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8	8
	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	4,650	5,470	4,820	5,470	5,410	6,530	5,470	6,530	5,470	6,530	5,470	6,530
Total Installed Cost (2022$)	14,060	14,880	14,230	14,880	14,880	15,940	14,880	15,940	14,880	15,940	14,880	15,940
	22,290	23,120	22,470	23,120	23,120	24,170	23,120	24,170	23,120	24,170	23,120	24,170
Annual Maintenance Cost (2022$)	90	90	90	90	90	90	90	90	90	90	90	90

1. COP values listed are assessed at a "ground loop" test condition, which is representative of closed loop ground source heat pumps (GSHP) operating conditions. However, DOE sets standards at a "water loop" test condition. The AHRI directory lists COP ratings at both sets of test conditions and is used to convert between them where necessary.
2. EER values listed are assessed at a full-load "ground loop" test condition, which is representative of closed loop GSHP operating conditions. However, DOE sets standards at a full-load "water loop" test condition. The AHRI directory lists EER ratings at all sets of test conditions and is used to convert between them where necessary.

Note:
Residential and commercial GSHPs are very similar - the main difference in data presented is the different capacity (3-ton vs. 4-ton) and slightly higher installation costs for commercial GSHP. DOE does not distinguish between residential and commercial units in its regulations.
Current standards went into effect on October 9, 2015. COP and EER ratings are converted from the “water loop” test condition to “ground loop.”
ENERGY STAR V. 3.2 went into effect January 1, 2012.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay parameters: (17.04, 1.64, 1).

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Residential Ground-Source Heat Pumps

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- Heating COP does not correlate with cooling EER.
- The ENERGY STAR criteria for water-to-air ground-source heat pumps are:

Type	Heating COP	Cooling EER
Closed Loop	3.6	17.1
Open Loop	4.1	21.1
Direct Expansion	3.6	16

- The most common GSHP is a closed-loop system in which water or an anti-freeze solution is circulated through plastic pipes buried underground. Open loop systems that employ ground water or surface water (e.g., open well, pond, lake) are used in some parts of the country, but water supply and water quality issues impose limitations on such applications.
- Installation cost is for a closed loop system and includes necessary accessories. The ground loop heat exchanger represents a majority of the installation cost. Installed costs for these systems vary widely.
- Variable speed ECMs improve performance on high-end models.

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Residential Natural Gas Heat Pumps

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DATA	2015	2020	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (kBtu/h)	60	60	60	60	60	60
COP (Heating)	1.3	1.3	1.3	1.3	1.3	1.3
COP (Cooling)	0.6	0.7	0.7	0.7	0.7	0.7
Annual Electric Use (kWh/y)[1]	1,500	1,500	1,500	1,500	1,500	1,500
Average Life (y)	12	12	12	12	12	12
	18	18	18	18	18	18
Retail Equipment Cost (2022$)[2]	12,940	12,940	12,940	12,940	12,940	12,940
	14,350	14,350	14,350	14,350	14,350	14,350
Total Installed Cost (2022$)[2]	14,700	14,700	14,700	14,700	14,700	14,700
	17,290	17,290	17,290	17,290	17,290	17,290
Annual Maintenance Cost (2022$)	200	200	200	200	200	200

1. Annual electric use accounts for the electricity consumption of components such as the heat pump fan.

Note:
Ranges represent the span of typical values observed in the market.

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Residential Natural Gas Heat Pumps

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- Residential natural gas heat pumps are not currently subject to DOE regulations. The California Energy Commission's (CEC) Title 24, Part 6 Section 112 does indicate cooling efficiency requirements for natural gas heat pumps.
- Natural gas heat pumps are much more popular in other parts of the world, such as Europe. Gas-fired cooling equipment currently comprises less than 1% of the residential air conditioning/heat pump market in the U.S.
- Currently, Robur is the predominant manufacturer of residential-sized natural gas heat pumps with sales operations in the U.S.. Robur units are 5-ton nominal cooling capacity, a size typically associated with larger homes. Since only one product is available, no mid-level or high efficiency categories are included in this analysis.
- The data represents air-source absorption heat pumps. Gas engine-driven vapor compression heat pumps are available in other parts of the world; York formerly offered the Triathlon gas engine-driven heat pump in the U.S. It is possible to couple either technology to the ground (ground-source) rather than the atmosphere (air-source).
- The absorption heat pump is a gas-fired, ammonia-water absorption cycle, combined with a high-efficiency low-pressure boiler integrated into one outdoor unit.
- The cooling efficiency of a gas-fired air-source absorption heat pump is considerably lower than for an electric air-source heat pump. Heating efficiency of an air-source heat pump (electric or gas-fired absorption) decreases as outdoor temperature decreases; however, the gas-fired absorption heat pump recovers waste heat from the combustion process to improve heating efficiency.

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Residential Cordwood Stoves

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DATA	2015[1]	2020[2]	2022[3]		2030[4]		2040[4]		2050[4]	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	50	50	50	50	50	50	50	50	50	50
Efficiency (Non-Catalytic) (HHV)[5]	63	71	71	80	71	80	71	80	71	80
Efficiency (Catalytic) (HHV)[5]	72	76	76	81	76	81	76	81	76	81
Average Life (y)	12	12	12	12	12	12	12	12	12	12
	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$) (Non-Catalytic)	2,880	1,670	1,670	2,300	1,670	2,300	1,670	2,300	1,670	2,300
Retail Equipment Cost (2022$) (Catalytic)	3,540	3,040	3,040	3,830	3,040	3,830	3,040	3,830	3,040	3,830
Total Installed Cost (2022$) (Non-Catalytic)[6]	8,290	7,090	7,090	7,710	7,090	7,710	7,090	7,710	7,090	7,710
Total Installed Cost (2022$) (Catalytic)[6]	8,950	8,460	8,460	9,240	8,460	9,240	8,460	9,240	8,460	9,240
Annual Maintenance Cost (2022$) (Non-Catalytic)[7]	190	190	190	190	190	190	190	190	190	190
Annual Maintenance Cost (2022$) (Catalytic)[7]	280	280	280	280	280	280	280	280	280	280

1. For 2015, assumed EPA default efficiencies, which were used by EPA to approximate the efficiency of stoves before the 2015 EPA rule required efficiency testing.
2. For 2020, assumed same efficiencies as estimated for 2022 given the most recent EPA rule went into effect in May 2020.
3. The 2022 High value is the highest EPA certified efficiency. The 2022 Typical value is the average of EPA certified efficiencies.
4. For 2030-2050, it is assumed that the same conditions as current would persist because no impending efficiency requirements are expected from EPA, given recency of 2020 rulemaking and current market factors.
5. Efficiency includes combustion and heat transfer efficiency and is based on the higher heating value (HHV) of the fuel.
6. Installed costs include the cost of hearth and stainless-steel chimney liner - materials and labor.
7. For catalytic stoves, annual maintenance cost includes periodic cost of replacing the catalytic combustor.

Note:
The range for average life represents the span of typical values.

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Residential Cordwood Stoves

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- Residential cordwood stoves that must meet EPA particulate limits fall into two broad classes based on whether they use a catalyst for air treatment. Catalytic wood stoves use a catalytic combustor to reduce emissions from the combustion air. Non-catalytic wood stoves use baffles and introduce secondary air above the flames to enable more complete combustion and reduce emissions.
- In 2015, EPA published an update to its New Source Performance Standards (NSPS), decreasing the emissions limit (previously set by 1988 EPA rule) to 4.5 grams per hour (g/h) for both catalytic and non-catalytic stoves. The new rule did not institute efficiency standards but required that manufacturers test and certify the efficiency of their stoves. This standard took full effect on January 1, 2016.
- In 2020, the NSPS limit for new room heaters was lowered to 2.5 g/h if tested with cord wood.
- Prior to the 2015 rule, manufacturers could either submit efficiency data from laboratory testing or certify with the default efficiency value designated by EPA. EPA's default efficiency values were 63% for non-catalytic wood stoves and 72% for catalytic wood stoves. Under this system, few manufacturers submitted efficiency test data to EPA.
- Multiple test standards are commonly used to assess stove efficiency, and data from product literature does not generally identify the efficiency test method.
- It is not possible to determine performance trends based on construction or configuration (e.g., cast iron vs. plate steel, powered blowers vs. no blowers, etc.) trends in specific equipment type or construction based on published efficiencies. Further, EPA certification data shows no significant relationship between emissions and heating efficiency.
- Cordwood stoves require chimneys for venting combustion gases. Whether conventional masonry chimneys are used or metal chimney liners, these add considerable cost to the overall system. Accordingly, installed costs can be twice that of the wood stove itself.

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Residential Cordwood Stoves

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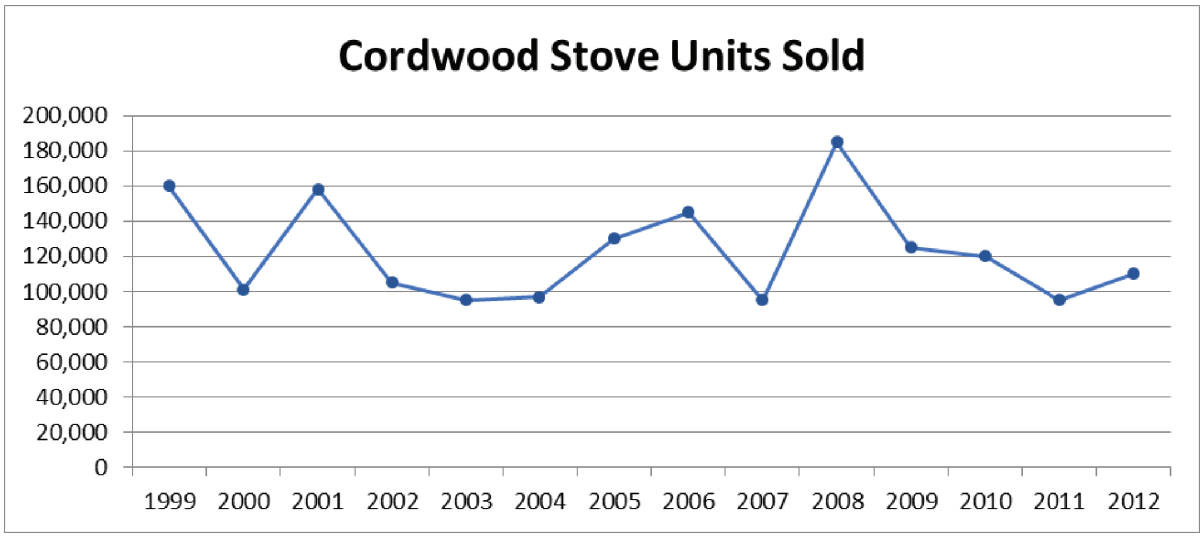
Cordwood stove shipments have averaged 123,000 per year since 1999 and have fluctuated approximately in accordance with fuel oil costs.



Source: *HPBA, no post-2012 sales data was publicly available at time of publication.*

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Residential Wood Pellet Stoves

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DATA	2015[1]	2020[2]	2022[3]		2030[4]		2040[4]		2050[4]	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	50	50	50	50	50	50	50	50	50	50
Efficiency (HHV)[5]	70	73	73	85	73	85	73	85	73	85
Annual Electricity Consumption (kWh)[6]	600	600	600	600	600	600	600	600	600	600
Average Life (y)	12	12	12	12	12	12	12	12	12	12
	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	3,900	3,120	3,120	4,000	3,120	4,000	3,120	4,000	3,120	4,000
Total Installed Cost (2022$)[7]	5,550	4,520	4,520	5,400	4,520	5,400	4,520	5,400	4,520	5,400
Annual Maintenance Cost (2022$)	310	310	310	310	310	310	310	310	310	310

1. For 2015, assumed EPA default efficiencies, which were used by EPA to approximate the efficiency of stoves before the 2015 EPA rule required efficiency testing.
2. For 2020, assumed same efficiencies as estimated for 2022 given the most recent EPA rule went into effect in May 2020.
3. The 2022 High value is the highest EPA certified efficiency. The 2022 Typical value is the average of EPA certified efficiencies.
4. For 2030-2050, it is assumed that the same conditions as current would persist because no impending efficiency requirements are expected from EPA, given recency of 2020 rulemaking and current market factors.
5. Efficiency includes combustion and heat transfer efficiency and is based on the HHV of the fuel.
6. The annual electric consumption estimates assume 6 months/year @ 100kW/mo based on DOE estimates.
7. Installed cost includes cost of hearth and vent pipe - materials and labor.

Note:
The range for average life represents the span of typical values.

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Residential Wood Pellet Stoves

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- In 2015, EPA published an update to its NSPS, limiting emissions for wood pellet stoves to 4.5 g/h. Prior to the 2015 EPA rule, most pellet stoves were exempt from EPA's NSPS requirements. The new rule did not institute efficiency standards but required that manufacturers test and certify the efficiency of their stoves. This standard took full effect on January 1, 2016.
- Prior to the 2015 rule, manufacturers could either submit efficiency data from laboratory testing or certify with the default efficiency value designated by EPA. EPA's default efficiency values were 63% for non-catalytic wood stoves and 72% for catalytic wood stoves. Under this system, few manufacturers submitted efficiency test data to EPA.
- Multiple test standards are commonly used to assess stove efficiency and data from product literature does not generally identify the efficiency test method.
- It is not possible to determine performance trends based on construction or configuration (e.g., cast iron vs. plate steel, powered blowers vs. no blowers, etc.) trends in specific equipment type or construction based on published efficiencies. Further, EPA certification data shows no significant relationship between emissions and heating efficiency.
- Wood pellet stoves may be able to be direct vented to the outdoors, eliminating the need for a chimney. This reduces the overall system cost as compared to a cord wood stove. However, they do use electricity to power the pellet feeder, the combustion air fan, and the blower. In the event of a power outage, a pellet stove can not operate without some back-up source of electricity (e.g., battery) .

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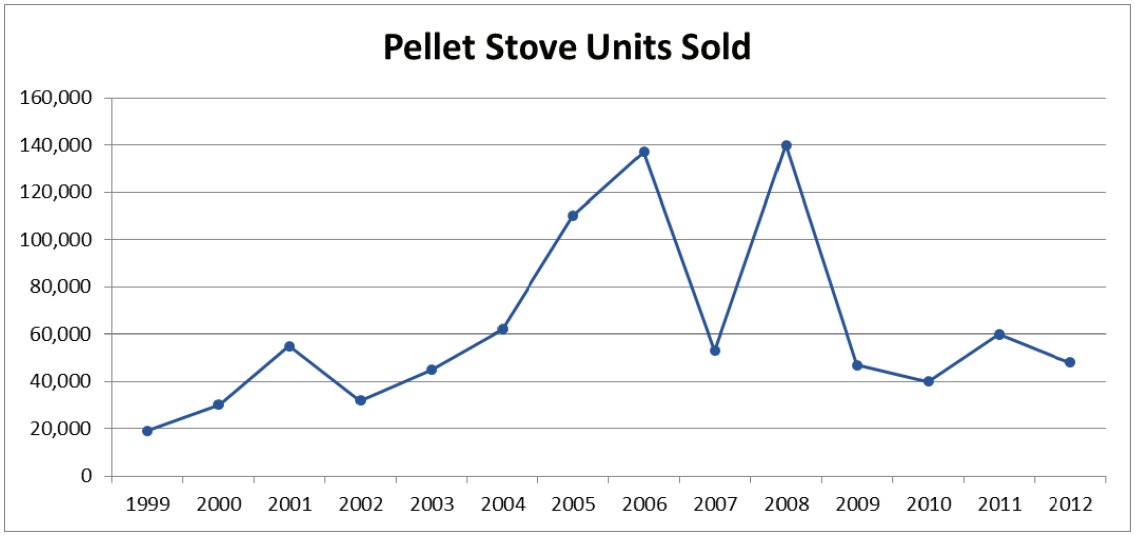
Wood pellet stove shipments grew substantially in the 2005 – 2008 time period but have averaged only 40,000 – 60,000 units since that time.



Source: *HPBA, no post-2012 sales data was publicly available at time of publication.*

Residential Water Heating

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Residential Gas-Fired Storage Water Heaters

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DATA	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	40	40	40	40	40	40	40	40	40	40	40	40	40
Uniform Energy Factor (UEF)[1]	0.58	0.63	0.61	0.61	0.66	0.84	0.83	0.61	0.84	0.61	0.84	0.61	0.84
Average Life (y)	13	13	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
Retail Equipment Cost (2022$)	590	880	420	420	490	720	700	420	720	420	720	420	720
	650	1,410	990	990	1,110	1,650	1,590	990	1,650	990	1,650	990	1,650
Total Installed Cost (2022$)	1,240	1,650	740	740	800	1,140	1,130	740	1,140	740	1,140	740	1,140
	1,240	2,880	1,690	1,690	1,850	3,130	3,160	1,690	3,130	1,690	3,130	1,690	3,130
Annual Maintenance Cost (2022$)[2]	20	20	20	20	20	20	20	20	20	20	20	20	20

1. Analysis is based on an average of medium and high draw pattern units, as this is most reflective of the market.
2. Maintenance includes manufacturer recommendation for the water heater to be drained and flushed annually to minimize deposition of sediment, maintain operating efficiency, and prolong product life. Available evidence indicates that this is performed in 10% of households.

Note:
Ranges represent the span of typical values.
Current standards went into effect April 16, 2015.
ENERGY STAR V. 4.0 went into effect January 5, 2022.
ENERGY STAR V. 5.0 will go into effect April 18, 2023
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.1, 1.76, 1).

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Residential Gas-Fired Storage Water Heaters

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
≥ 20 gal and ≤ 55 gal	Very Small	UEF=0.3456-(0.002*Gal)	No models on the market	NA
	Low	UEF=0.5982-(0.0019*Gal)	0.54 for a 29-gallon water heater	NA
	Medium	UEF=0.6483-(0.0017*Gal)	0.58 for a 38-gallon water heater	0.64
	High	UEF=0.692-(0.0013*Gal)	0.64 for a 48-gallon water heater	0.68
> 55 gal and ≤ 100 gal	Very Small	UEF=0.647-(0.0006*Gal)	No models on the market	NA
	Low	UEF=0.7689-(0.0005*Gal)	No models on the market	NA
	Medium	UEF=0.7897-(0.0004*Gal)	No models on the market	0.78
	High	UEF=0.8072-(0.0003*Gal)	No models on the market	0.80

- There are currently no models on the market above 55 gallons (gal) due to the high UEF, which would require using condensing or gas-fired heat pump (e.g., absorption) technology to achieve.
- The cost of installation is typically $600 to $1200, which exceeds that of electric water heaters. This difference can be attributed to multiple differences; for example, gas-fired heaters require an extra 1.5 hours of labor for 2 plumbers.
- Condensing units are high efficiency and use PVC venting instead of stainless-steel. Condensing units also use an electrical supply for electronic ignition and power venting. Some building codes require condensate neutralizer filters.

[1]Energy Conservation Standards for Residential Water Heaters. 10 CFR 430.32(d).

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Residential Gas-Fired Storage Water Heaters

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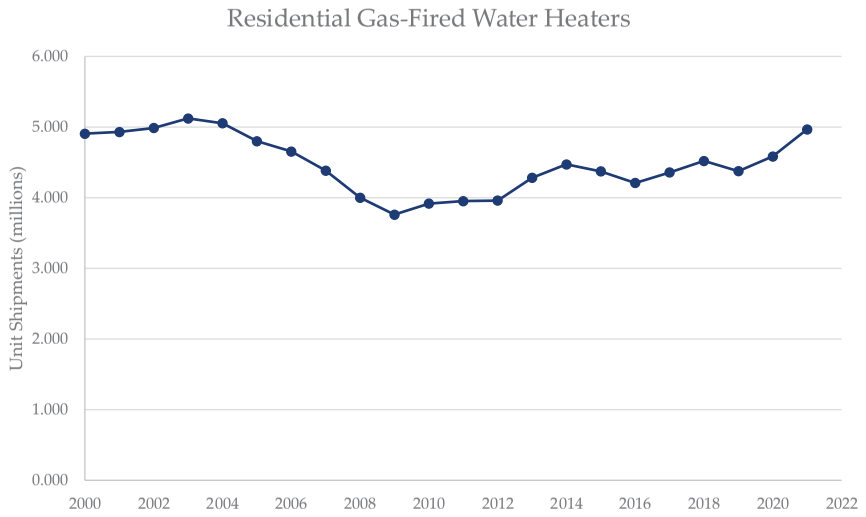
Shipments were flat at 5 million units per year through 2004, then declined gradually over 5 years to a new plateau at 4 million units until rising again back to 5 million units in 2021.



Source: *AHRI*

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Residential Oil-Fired Water Heaters

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DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	32	32	32	32	32	32	32	32	32	32	32
Uniform Energy Factor[1]	0.51	0.67	0.64	0.66	0.68	0.66	0.68	0.66	0.68	0.66	0.68
Average Life (y)	13	13	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Retail Equipment Cost (2022$)	1,590	1,880	1,380	1,400	1,480	1,400	1,480	1,400	1,480	1,400	1,480
	1,710	2,410	2,810	2,870	3,030	2,870	3,030	2,870	3,030	2,870	3,030
Total Installed Cost (2022$)	2,350	2,650	2,620	2,650	2,730	2,650	2,730	2,650	2,730	2,650	2,730
	2,470	3,350	4,050	4,120	4,280	4,120	4,280	4,120	4,280	4,120	4,280
Annual Maintenance Cost (2022$)[2]	210	210	210	210	210	210	210	210	210	210	210

1. Analysis is based on an average of medium and high draw pattern units, as this is most reflective of the market.
2. Oil-fired storage water heaters are typically cleaned and maintained under maintenance contracts. The annual cost of typical maintenance is based on maintenance contract prices from different oil-fired product suppliers as specified in the CWH EERE 2022 Preliminary Analysis.

Note:
Ranges represent span of typical values.
Current standards went into effect April 16, 2015.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (16.2, 1.70, 1).

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Residential Oil-Fired Water Heaters

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
≤ 50 gal	Very Small	UEF=0.2509-(0.0012*Gal)	No models on the market	NA
	Low	UEF=0.533-(0.0016*Gal)	No models on the market	NA
	Medium	UEF=0.6078-(0.0016*Gal)	No models on the market	NA
	High	UEF=0.6815-(0.0014*Gal)	0.64 for a 29-gallon water heater	NA

- There are no ENERGY STAR requirements for oil-fired storage water heaters.
- Annual shipments of residential oil-fired storage water heaters are approximately 4,000, which is less than 1% of shipments of residential gas-fired storage water heaters.
- Oil-fired storage water heaters often have smaller tanks with larger input ratings relative to natural gas-fired and electric storage water heaters.
- No condensing residential oil-fired storage water heaters currently exist in the U.S. market. Condensing oil-fired water heaters are generally not considered technologically feasible because the sulfur content in fuel oil leads to the condensate becoming corrosive.
- Residential oil-fired water heaters utilize power burners and have at least some level of electrical power consumption.
- The most efficient models on the market use a proprietary "turbo-flue" design to increase heat transfer to water.

[1]Energy Conservation Standards for Residential Water Heaters. 10 CFR 430.32(d).

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Residential Oil-Fired Water Heaters

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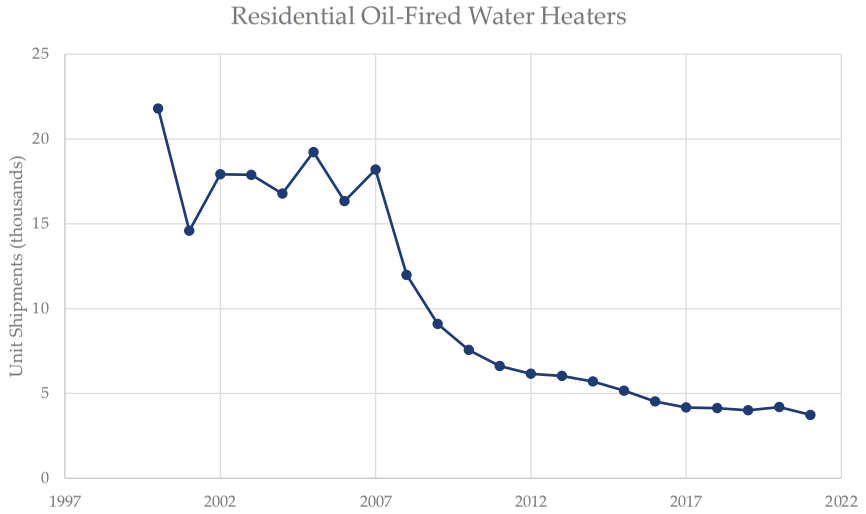
Shipments peaked at about 22,000 units in 2000 and have decreased since then, with an exponential decay occurring since 2007. Only about 4,000 units were shipped in 2021.



Source: *CWH EERE 2022 Preliminary Analysis*

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Residential Electric Resistance Storage Water Heaters

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DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	36	36	36	36	36	36	36	36	36	36	36
Uniform Energy Factor[1]	0.88	0.93	0.92	0.92	0.93	0.92	0.93	0.92	0.93	0.92	0.93
Average Life (y)	13	13	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Retail Equipment Cost (2022$)	290	350	330	330	600	330	600	330	600	330	600
	530	650	760	760	850	760	850	760	850	760	850
Total Installed Cost (2022$)	590	710	500	500	550	500	550	500	550	500	550
	940	1,290	1,310	1,310	1,430	1,310	1,430	1,310	1,430	1,310	1,430
Annual Maintenance Cost (2022$)[2]	20	20	20	20	20	20	20	20	20	20	20

1. Beginning in 2016, the efficiency metric for water heaters changed from energy factor (EF) to UEF based on DOE test procedures. The UEF values for the installed base in 2015 are converted values equivalent to 0.90 EF. Analysis is based on an average of low and medium draw pattern units, as this is most reflective of the market.
2. Similar to gas-fired and oil-fired storage water heaters, manufacturers recommend that electric storage water heaters be drained and flushed annually to minimize deposition of sediment, maintain operating efficiency, and prolong product life. The available evidence indicates that this practice is done in 10% of households.

Note:
Ranges represent span of typical values.
Current standards went into effect April 16, 2015.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.7, 1.57, 1).

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Residential Electric Resistance Storage Water Heaters

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
≥ 20 gal and ≤ 55 gal	Very Small	UEF=0.8808-(0.0008*Gal)	No models on the market	2.00
	Low	UEF=0.9254-(0.0003*Gal)	0.92 for a 27-gallon water heater	2.00
	Medium	UEF=0.9307-(0.0002*Gal)	0.92 for a 45-gallon water heater	2.00
	High	UEF=0.9349-(0.0001*Gal)	0.93 for a 50-gallon water heater	2.00
> 55 gal and ≤ 120 gal	Very Small	UEF=1.9236-(0.0011*Gal)	No models on the market	2.20
	Low	UEF=2.0440-(0.0011*Gal)	No models on the market	2.20
	Medium	UEF=2.1171-(0.0011*Gal)	2.05 for a 58-gallon water heater	2.20
	High	UEF=2.2418-(0.0011*Gal)	2.15 for a 80-gallon water heater	2.20

- The federal standards for residential electric storage water heaters apply to both electric resistance storage water heaters and heat pump water heaters.
  - The Federal standard levels for the ≤ 55-gallon range are achievable through electric resistance and heat pump technology.
  - The Federal standards for the > 55-gallon range and all ENERGY STAR levels are only achievable through heat pump technology.
- Typical storage volumes range from 25-55 gallons for electric resistance storage water heaters and 45-80 gallons for heat pump water heaters (HPWHs).

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Residential Electric Resistance Storage Water Heaters

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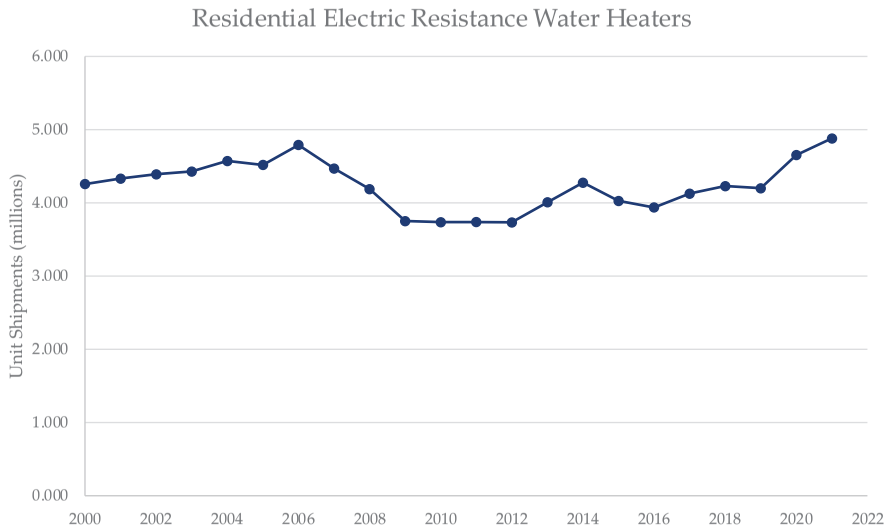
Shipments peaked in 2006 then dropped a total of 22 percent over three years. Shipments have gradually increased since then and were at the highest level in 2021.



Source: *AHRI*

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Residential Heat Pump Water Heaters

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DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	36	36	36	36	36	36	36	36	36	36	36
Uniform Energy Factor[1]	2.05	3.28	3.33	3.30	3.73	3.33	3.73	3.33	3.73	3.33	3.73
Average Life (y)	13	13	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Retail Equipment Cost (2022$)[2]	1,290	1,410	630	630	670	630	670	630	670	630	670
	1,650	1,760	1,440	1,440	1,670	1,370	1,590	1,300	1,510	1,240	1,430
Total Installed Cost (2022$)[2]	1,710	1,880	870	870	980	870	980	870	980	870	980
	2,940	3,000	2,230	2,230	2,450	2,120	2,330	2,010	2,210	1,910	2,100
Annual Maintenance Cost (2022$)[3]	20	20	20	20	20	20	20	20	20	20	20

1. Analysis is based on an average of low and medium draw pattern units, as this is most reflective of the market.
2. It is expected that costs for HPWHs will decrease over time as these products become more common. This analysis estimates these cost decreases for the higher range of costs.
3. For heat pump water heater design options, DOE assumed higher maintenance cost to take into account annual cleaning of the air filter, preventative maintenance cost to check the evaporator and refrigeration system, inspection of the condensate withdrawal system, and replacement of the condensate neutralizer filter, if applicable. However, this maintenance is estimated to occur in only 10% of households, so overall maintenance cost is similar to that of other electric resistance water heaters.

Note:
Ranges represent span of typical values.
ENERGY STAR V. 4.0 went into effect January 5, 2022.
Assume same lifetime as electric resistance water heaters.

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Residential Heat Pump Water Heaters

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- Technology improvements have advanced efficiency and reliability, but the high first-cost and lack of awareness among consumers and contractors still precludes high-volume market penetration.
- New Federal standards that came into effect in April 2015 effectively mandate heat pump technology for electric storage water heaters with storage volume > 55 gallons.
- Integrated models are the most common configuration for residential HPWHs. Several major water heater manufacturers produce such models, and other competitors offer integrated or add-on units (for existing electric or indirect storage water heaters).
- Sales are estimated to be driven partly by rebates and tax credits at the utility, local, state, and Federal level.
- Resistive heating elements are virtually 100% efficient, but there is a jump in efficiency when heat pump technology is adopted because heat pumps' COP are usually between 2.5 and 4.
- Heat pumps raise the water temperature more slowly than resistive heating elements, so most models use backup resistive elements along with the heat pump when hot water demand is high. Most HPWHs allow the consumer to control whether resistive elements are used in periods of high demand (e.g., "hybrid mode" or "heat pump only mode").

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Residential Heat Pump Water Heaters

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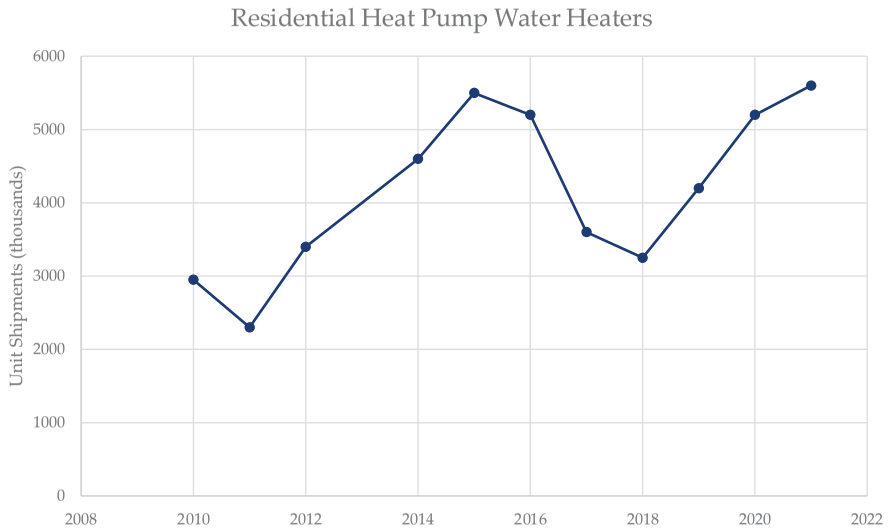
Shipments make up a small portion of electric resistance heaters, with a peak of only about 5,500 units, occurring in both 2015 and 2021.



Source: *ENERGY STAR*

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DATA	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	ENERGY STAR V. 4.0	Typical	Typical	Typical	Typical
Typical Capacity (ft^2)[1]	42	42	40	40	40	40	40
	65	65	54.4	54.4	54.4	54.4	54.4
Solar Uniform Energy Factor (SUEF)[2]	3.0	3.0	3.0	99.0	99.0	99.0	99.0
Average Life (y)	15	15	15	15	15	15	15
	30	30	30	30	30	30	30
Retail Equipment Cost (2022$)	7,710	7,710	6,430	6,430	6,430	6,430	6,430
Total Installed Cost (2022$)	10,650	10,650	8,060	8,060	8,060	8,060	8,060
Annual Maintenance Cost (2022$)[3]	80	80	80	80	80	80	80

1. Capacity selections are based on the range observed from medium draw units in the ENERGY STAR database. Medium draw represented the largest portion of units.
2. An SUEF of 3.0 is the required threshold for ENERGY STAR certification, yet a value of 99 was the most common observed SUEF among medium draw units. Note that an SUEF of 99 indicates that no backup heating was required for the applicable draw pattern, and all energy was provided by the solar collector. Since SUEF is a measure of hot water energy out divided by electrical or gas backup energy in, it will be infinite for cases where the collector provides all the hot water needed for the draw pattern – the Solar Rating and Certification Corporation's (SRCC's) OG-300 software is written to assign an SUEF of 99 to this case.
3. Annual maintenance is expected to be 0.5% to 1% of the total installation for 2022, 2030, 2040, and 2050.

Note:
Ranges represent span of typical values.
ENERGY STAR V. 4.0 went into effect January 5, 2022.

Residential Solar Water Heaters

- Solar water heaters are not subject to federal energy conservation standards. The ENERGY STAR requirements are:

Applicable Products	Backup Fuel	ENERGY STAR Requirement	Test Method
Whole-home solar units	Gas	SUEF ≥ 3.0	ICC 900/SRCC 300-2020 Solar Thermal System Standard, Appendix A: Solar Uniform Energy Factor Procedure for Solar Water Heating Systems
	Electric	SEF ≥ 1.8	

- Solar water heaters can be either active or passive. An active system uses an electric pump to circulate the heat transfer fluid; a passive system has no pump. Most solar water heaters in the U.S. are the active type.
- Solar water heaters are also characterized as open loop (also called "direct") or closed loop (also called "indirect"). An open-loop system circulates household (potable) water through the collector. A closed-loop system uses a heat transfer fluid (water or diluted antifreeze, for example) to collect heat and a heat exchanger to transfer the heat to household water. Direct systems were observed as the most common product type and subject of this analysis.
- In 2020, stakeholders from the solar thermal industry developed the Solar Uniform Energy Factor (SUEF) Specification for solar water heaters to align with the UEF metric used by DOE for other water heating technologies.
- SUEF is also the metric used by the current ENERGY STAR Specification, and it replaced the Solar Energy Factor (SEF) metric.
- Over two-third of the current solar water heater market is in the southern or western U.S. (including Hawaii). A collector area of 42 square feet (ft^2) would be typical for these areas. Colder areas of the U.S. would require a larger collector (e.g., 65 ft^2).
- Installed costs are higher for colder areas where larger collectors are required. Costs also vary widely depending on collector quality, type of system, and site-specific characteristics.

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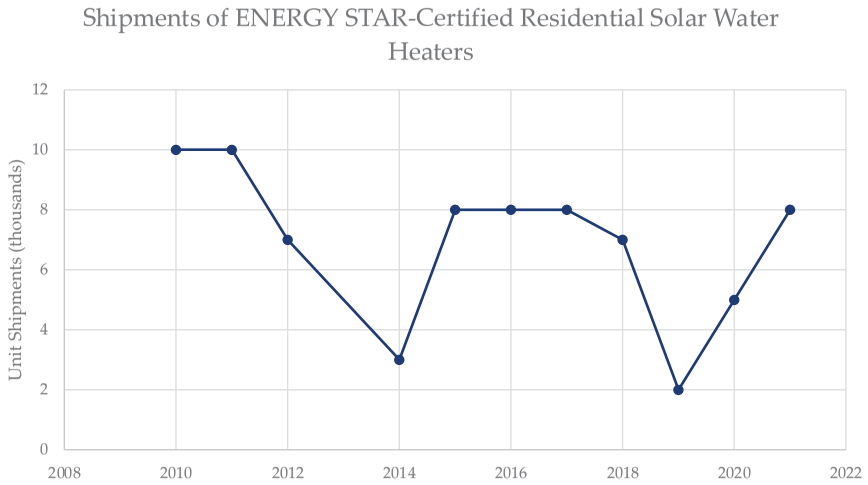
The shipments data below only represents ENERGY STAR-certified solar water heaters, as ENERGY STAR did not provide a market penetration rate. Solar water heaters have a small market share, with only 10,000 shipments at the peak in 2010 and 2011.



Source: *ENERGY STAR*

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Residential Gas-Fired Instantaneous Water Heaters

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DATA	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	199	199	199	199	199	199	199	199	199	199	199	199	199
Uniform Energy Factor (UEF)[1]	0.81	0.89	0.81	0.92	0.87	0.97	0.95	0.92	0.97	0.92	0.97	0.92	0.97
Average Life (y)	19	19	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$)	1,410	1,180	430	580	580	610	610	580	610	580	610	580	610
	1,760	1,410	1,020	1,360	1,350	1,430	1,430	1,360	1,430	1,360	1,430	1,360	1,430
Total Installed Cost (2022$)	2,590	1,760	920	1,070	950	1,090	1,090	1,070	1,090	1,070	1,090	1,070	1,090
	3,820	3,350	2,860	3,160	3,140	3,230	3,220	3,160	3,230	3,160	3,230	3,160	3,230
Annual Maintenance Cost (2022$)[2]	90	90	90	90	90	90	90	90	90	90	90	90	90

1. Analysis is based on an average of low, medium, and high draw pattern units, as this is most reflective of the market.
2. Annual maintenance includes deliming to minimize deposition of sediment in the heat exchanger, maintain operating efficiency and prolong product life. Also includes additional tasks, including inspection of the ignition device, gas valve, controls, thermostat, and venting.

Note:
Ranges represent span of typical values.
Current standards went into effect April 16, 2015.
ENERGY STAR V. 4.0 went into effect January 5, 2022.
ENERGY STAR V. 5.0 will go into effect April 18, 2023.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (21.3, 1.76, 1).

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Residential Gas-Fired Instantaneous Water Heaters

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
<2 gal and >50,000 Btu/h	Very Small	UEF=0.80	No models on the market	0.87
	Low	UEF=0.81	No models on the market	0.87
	Medium	UEF=0.81	0.81	0.87
	High	UEF=0.81	0.81	0.87

- The ENERGY STAR levels require the use of condensing technology.
- All of the major water heater manufacturers now offer an instantaneous water heater model.
- The maintenance costs include cleaning the water inlet filter and the heat exchanger of mineral deposits and replacing the water valve approximately once every five years for all instantaneous water heaters.
- When replacing a storage water heater with an instantaneous water heater, there are significant additional costs to upsize the gas supply line to ¾ inch from the typical ½ inch and change the venting.

[1]Energy Conservation Standards for Residential Water Heaters. 10 CFR 430.32(d).

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Residential Gas-Fired Instantaneous Water Heaters

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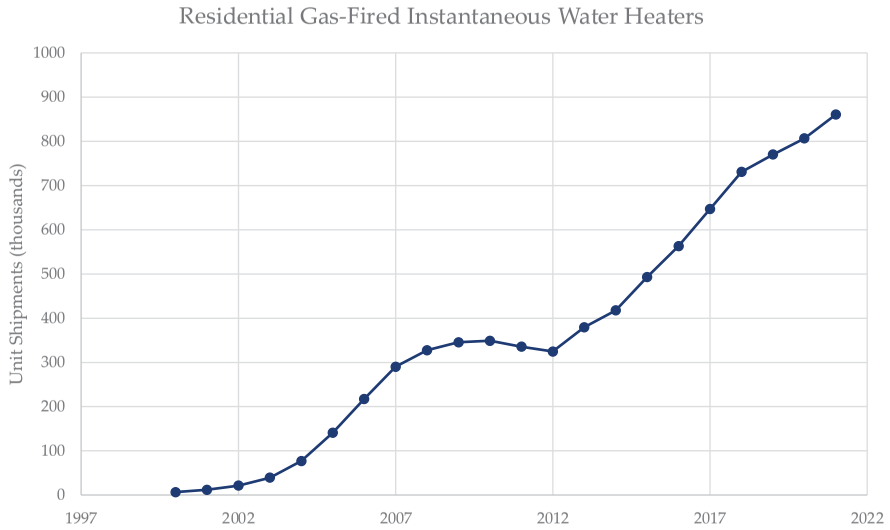
Shipments for Gas-Fired Instantaneous Water Heaters have grown steadily with nearly no shipments in 2000 and a peak of about 850,000 units in 2021.



Source: *CWH EERE 2022 Preliminary Analysis*

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Residential Electric Instantaneous Water Heaters

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DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Representative Input Rate (kW)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Uniform Energy Factor (UEF)[1]	0.96	0.96	0.91	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$)	260	260	260	260	260	260	260	260	260	260	260
Total Installed Cost (2022$)	520	520	520	520	520	520	520	520	520	520	520
Annual Maintenance Cost (2022$)[2]	90	90	90	90	90	90	90	90	90	90	90

1. Analysis is based on an average of low, medium, and very small draw pattern units, as this is most reflective of the market.
2. Annual maintenance costs not provided in CWH EERE 2022 Preliminary Analysis. Maintenance costs determined from the following calculation: GIWH - (GSWH - ESWH) - i.e., the difference factor in maintenance between gas and electric storage heat pumps applied to gas instantaneous heat pumps.

Note:
Current standards went into effect April 16, 2015.
Assume same lifetime as gas-fired instantaneous water heaters.

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Residential Electric Instantaneous Water Heaters

- The Federal standards are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes
<2 gal	Very Small	UEF=0.91	0.91
	Low	UEF=0.91	0.91
	Medium	UEF=0.91	No models on the market
	High	UEF=0.92	No models on the market

- Electric instantaneous water heaters use electric resistance heating elements to heat water when there is a demand. Resistive heating elements are virtually 100% efficient, and the small storage capacities of these products means that they do not lose significant amounts of heat to the environment.
- The federal standards for these products require UEFs of 0.91 for very small, low, and medium draw pattern models and 0.92 for high draw pattern models.
- Most products currently on the market are in the very small draw pattern or the low draw pattern because electric resistance elements can only supply a limited quantity of heat on an instantaneous basis due to circuit amperage limitations.
- Many products are designed for point-of-use applications, such that the water heater only supplies water to one faucet or showerhead.

Residential Appliances

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Residential Refrigerator-Freezers (Top)

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DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	19	19	19	19	19	19	19	19	19	19	19	19
Energy Consumption (kWh/y)[3]	512	401	411	401	370	358	401	358	401	358	401	358
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	670	750	740	750	760	760	750	760	750	760	750	760
Total Installed Cost (2022$)	670	750	740	750	760	760	750	760	750	760	750	760
Annual Maintenance Cost (2022$)[4]	10	10	10	10	10	10	10	10	10	10	10	10

1. Product Class 3 is used for this analysis (Refrigerator-freezers—automatic defrost with top-mounted freezer without through-the-door ice service and all-refrigerator—automatic defrost).
2. The volume shown here is the nominal total volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. The 2015 installed base energy consumption value is based on an adjusted volume of 21 cubic feet (ft^3). Energy consumption values for the 2020 installed base and 2022 and beyond are based on an adjusted volume of 22 ft^3, representing the current market.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics, ice maker), not replaceable components (e.g., water filters).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect in September 2014.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (10.26, 1.28, 5.13).

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Residential Refrigerator-Freezers (Side)

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DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	26	26	25	25	25	25	25	25	25	25	25	25
Energy Consumption (kWh/y)[3]	893	693	705	693	635	610	693	610	693	610	693	610
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	1,400	1,130	1,130	1,130	1,160	1,470	1,130	1,470	1,130	1,470	1,130	1,470
Total Installed Cost (2022$)	1,400	1,130	1,130	1,130	1,160	1,470	1,130	1,470	1,130	1,470	1,130	1,470
Annual Maintenance Cost (2022$)[4]	30	20	20	20	20	30	20	30	20	30	20	30

1. Product Class 7 is used for this analysis (Refrigerator-freezers—automatic defrost with side-mounted freezer with through-the-door ice service).
2. The volume shown here is the nominal total volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 32 ft^3 for all analysis years.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics, ice maker), not replaceable components (e.g., water filters).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect in September 2014.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (10.26, 1.28, 5.13).

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Residential Refrigerator-Freezers (Bottom)

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DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	19	19	19	19	19	19	19	19	19	19	19	19
Energy Consumption (kWh/y)[3]	547	473	521	473	469	430	473	430	473	430	473	430
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	1,190	920	920	920	920	930	920	930	920	930	920	930
Total Installed Cost (2022$)	1,190	920	920	920	920	930	920	930	920	930	920	930
Annual Maintenance Cost (2022$)[4]	30	20	20	20	20	20	20	20	20	20	20	20

1. Product Class 5 is used for this analysis (Refrigerator-freezers—automatic defrost with bottom-mounted freezer without through-the-door ice service).
2. The volume shown here is the nominal total volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 23 ft^3 for all analysis years.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics, ice maker), not replaceable components (e.g., water filters).

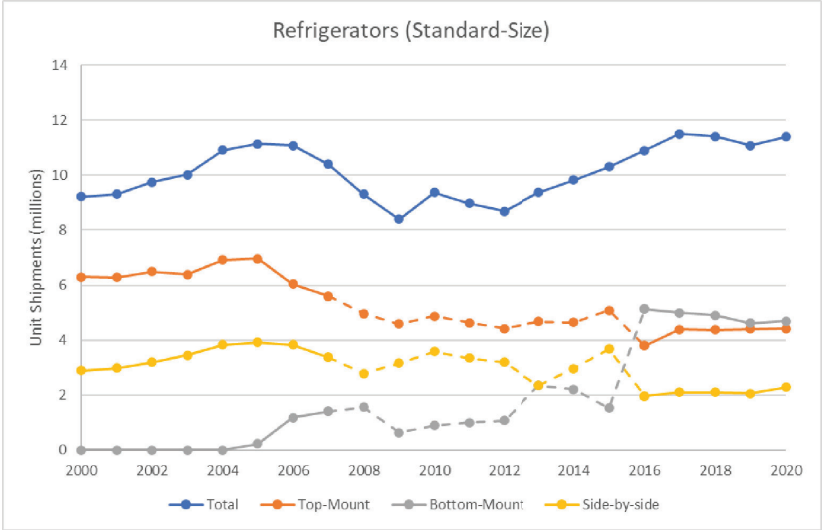
Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect in September 2014.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (10.26, 1.28, 5.13).

Residential Refrigerator-Freezers

- Current Federal standards[1]:
  - Compliance required beginning September 15, 2014
  - Models divided into 32 product classes based on size (standard or compact), location of freezer (top, bottom, or side), type of defrost (automatic or manual), installation configuration (freestanding or built-in), and presence and configuration (through-the-door or inside cabinet) of automatic icemaker
  - Limits on annual electricity consumption expressed as functions of adjusted volume[2]
  - New product classes for built-in units
  - Amount by which standards are tightened varies by product class
- ENERGY STAR criteria limit annual electricity consumption to 10% less than the Federal standard
- Energy efficiency opportunities for refrigerators include:
  - More efficient compressor, including variable speed compressors
  - Brushless direct current (DC) fan motor (also known as ECM motor)
  - Variable defrost
  - Larger condenser
  - Dual evaporators
  - Vacuum-insulated panels
  - Refrigerants (Isobutane vs. R134a)

[1]Energy Conservation Standards for Residential Refrigerators, Refrigerator-Freezers, and Freezers. 10 CFR 430.32(a).
[2]Adjusted Volume (AV) = (Fresh Volume) + 1.76 × (Freezer Volume)

Annual shipment volumes have rebounded from a sharp decline between 2006 and 2009, reaching approximately 11.4 million units in 2020.



Source: *Appliance Magazine; DOE's CCD, as of December 2017; ENERGY STAR Unit Shipment Data (2017-2020); Guidehouse analysis.* Dashed lines are a combination of interpolated and available data.

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Residential Refrigerator-Freezers

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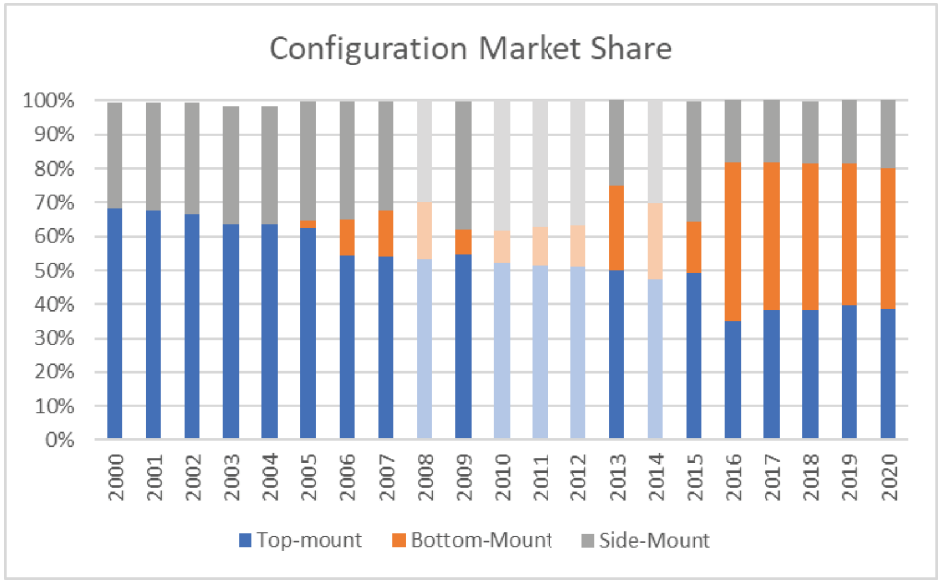
Bottom-mount units have gained market share, surpassing top-mount units since 2016.



Sources: *RF EERE 2021 Preliminary Analysis; DOE's CCD, as of December 2017; Guidehouse analysis.* Lightly shaded bars indicate interpolated data.

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Residential Freezers (Chest)

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DATA[1]	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	16	15	15	15	15	15	15	15	15	15	15
Energy Consumption (kWh/y)[3]	360	297	297	297	287	297	287	297	287	297	287
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	510	590	680	680	690	680	690	680	690	680	690
Total Installed Cost (2022$)	510	590	680	680	690	680	690	680	690	680	690
Annual Maintenance Cost (2022$)[4]	10	10	10	10	10	10	10	10	10	10	10

1. Product Class 10 is used for this analysis (Chest freezers and all other freezers except compact freezers).
2. The volume shown here is the nominal volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume (zero for freezers) plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 26 ft^3, which is the average adjusted volume for units with a rounded total refrigerated volume of 15 ft^3 per the DOE CCD.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics)

Note:
Current standard went into effect in September 2014.
ENERGY STAR excluded as no products at the typical capacity are ENERGY STAR compliant.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (21.96, 1.83, 1).

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Residential Freezers (Upright)

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DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	17	17	18	18	18	18	18	18	18	18	18	18
Energy Consumption (kWh/y)[3]	615	446	497	493	448	441	493	441	493	441	493	441
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	690	880	830	830	830	830	830	830	830	830	830	830
Total Installed Cost (2022$)	690	880	830	830	830	830	830	830	830	830	830	830
Annual Maintenance Cost (2022$)[4]	10	10	10	10	10	10	10	10	10	10	10	10

1. Product Class 9 is used for this analysis (Upright freezers with automatic defrost).
2. The volume shown here is the nominal volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume (zero for freezers) plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 31 ft^3, which is the average adjusted volume for units with a rounded total refrigerated volume of 18 ft^3 per the DOE CCD.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan electronics).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect September 2014.
Assume same lifetime as chest freezers.

Residential Freezers

- Current Federal standards[1]:
  - Compliance required beginning September 15, 2014
  - Models divided into 10 product classes based on size (standard or compact), orientation (chest or upright), type of defrost (automatic or manual), installation configuration (freestanding or built-in), and presence of automatic icemaker
    - Current analysis focuses on the two representative product classes analyzed in the recent rulemaking, chest and upright freezers.
  - Limits on annual electricity consumption expressed as functions of adjusted volume[2]
    - Chest freezers and all other freezers except compact freezers (PC 9): 9.88AV + 143.7
    - Upright freezers with automatic defrost (PC 10): 12.43AV + 326.1
- ENERGY STAR criteria limit annual electricity consumption to 10% less than the Federal standard
  - No ENERGY STAR compliant products at the typical capacity for chest freezers
- Energy efficiency opportunities for freezers include:
  - Higher efficiency and/or variable-speed compressor systems
  - Larger heat exchangers
  - Permanent-magnet fan motor systems (vs. shaded pole motor (SPM) and PSC fan motors)
  - Demand defrost systems
  - Vacuum-insulated panels
  - Thicker insulation (though at a loss of consumer utility)
  - Refrigerants (Isobutane vs. R134a)
  - Variable anti-sweat heating
  - Use of forced convection condenser (for upright freezers)

[1]Energy Conservation Standards for Residential Refrigerators, Refrigerator-Freezers, and Freezers. 10 CFR 430.32(a).
[2]Adjusted Volume (AV) = (Fresh Volume) + 1.76 × (Freezer Volume).

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Residential Freezers

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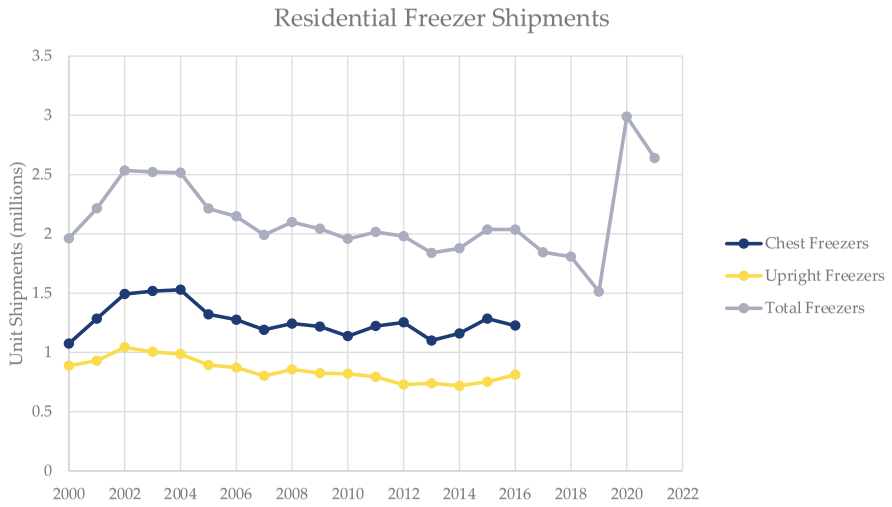
Shipment volumes held steady between 2007 to 2016 at about 2 million units per year. Shipments jumped to 3 million units in 2020. Chest freezers represent about 60% of the market.



Sources: *Appliance Magazine* from 2000 to 2016*; ENERGY STAR from 2017 to 2021*

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Residential Natural Gas Cooktops

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	9	9	9	9	9	9	9	9	9	9
	23	23	23	23	23	23	23	23	23	23
Integrated Annual Energy Consumption (kBtu/y)[1]	1,061	914	914	730	914	730	914	730	914	730
Cooking Efficiency (%)	40	45	45	52	45	52	45	52	45	52
Average Life (y)	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	290	310	310	330	310	330	310	330	310	330
Total Installed Cost (2022$)[2]	420	460	460	480	460	480	460	480	460	480
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to Integrated Annual Energy Consumption (IAEC) (kBtu/h). The Consumer Cooking Products EERE 2020 notice of proposed determination (NOPD) used for 2020 and beyond in this analysis also determined IAEC using a different test procedure than the Consumer Cooking Products EERE 2016 SNOPR.
2. Equipment and installed costs are for cooktops only (not combined range units).
3. Annual maintenance costs are negligible.

Note:
The range for typical capacity represents the span of typical values.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (14.56, 5.73).

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Residential Natural Gas Ovens

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	16	16	16	16	16	16	16	16	16	16
	18	18	18	18	18	18	18	18	18	18
Typical Cavity Volume (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kBtu/y)[1]	2,038	1,960	1,960	1,831	1,960	1,831	1,960	1,831	1,960	1,831
Cooking Efficiency (%)	6.6	6.9	6.9	7.3	6.9	7.3	6.9	7.3	6.9	7.3
Average Life (y)	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	740	770	770	810	770	810	770	810	770	810
Total Installed Cost (2022$)[2]	870	920	920	950	920	950	920	950	920	950
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to IAEC (kBtu/y). The 2015 IAEC value is reflective of freestanding standard gas ovens, which was previously determined to be the most representative product class. IAEC for 2020 and beyond is reflective of freestanding self-clean gas ovens, which is the product class that makes up the majority of historical and projected gas oven shipments.
2. Equipment and installed costs are for ovens only (not combined ranges). Costs are reflective of freestanding self-clean oven units with single oven component, which represent the majority of the market.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (14.56, 5.73).

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Residential Natural Gas Ranges

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity of Cooktop Component (kBtu/h)	9	9	9	9	9	9	9	9	9	9
	23	23	23	23	23	23	23	23	23	23
Typical Capacity of Oven Component (kBtu/h)	16	16	16	16	16	16	16	16	16	16
	18	18	18	18	18	18	18	18	18	18
Typical Cavity Volume of Oven Component (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kBtu/y)[1]	3,099	2,874	2,874	2,561	2,874	2,561	2,874	2,561	2,874	2,561
Average Life (y)	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$) [2]	750	770	770	850	770	850	770	850	770	850
Total Installed Cost (2022$) [2]	900	920	920	1,000	920	1,000	920	1,000	920	1,000
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. IAEC of a natural gas range is calculated as the sum of the IAEC for a natural gas cooktop and natural gas oven. IAEC of the oven component is reflective of freestanding self-clean gas ovens, which represent the majority of the market. The 2015 IAEC value of the oven component is reflective of freestanding standard gas ovens, which was previously determined to be the most representative product class.
2. Retail and installed cost are reflective of a typical unit with standard 30-inch width and 4 to 5 cooking top heating elements. Based on data from DOE rulemakings, Gordian's RSMeans Data – Building Construction Costs 2023, and distributors, total installed cost is estimated to be around $150 more than retail equipment cost.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (14.56, 5.73).

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Residential Natural Gas Cooktops, Ovens, and Ranges

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- DOE analyzes cooktops and ovens separately, although they are often sold together in a single unit that combines both a cooktop and an oven into a product referred to as a range.
- Since January 1, 1990, gas cooking products with an electrical supply cord have been required to not be equipped with a constant burning pilot light. This requirement extended to gas cooking products without an electrical supply cord, as of April 9, 2012.
- DOE published a final rule in 2009[1] in which it determined that no standard for cooking efficiency would be cost-justified.
- DOE initiated a standards rulemaking in 2014 to consider amended standards for cooking products, including gas cooktops and ovens[2].
- On September 2, 2016, DOE proposed performance-based standards for gas cooktops and ovens that would take effect in 2020, if adopted.
- DOE established the new IAEC metric, in kBtu/y, to replace cooking efficiency (%).
- On December 14, 2020, DOE initially determined that amended energy conservation standards for consumer conventional cooking products would not be economically justified and would not result in significant conservation of energy[3].
- On February 2, 2023, DOE proposed new and amended energy conservation standards for consumer conventional cooking products[4].
- The IAEC of a range is calculated as the sum of the IAECs for cooktops and ovens. However, retail and installation costs for a range are similar to the cost of an oven.

[1]Energy Conservation Standards for Certain Consumer Products (Dishwashers, Dehumidifiers, Microwave Ovens, and Electric and Gas Kitchen Ranges and Ovens) and for Certain Commercial and Industrial Equipment (Commercial Clothes Washers); Final Rule. 74 FR 16040.
[2]Energy Conservation Standards for Residential Conventional Cooking Products; Supplemental notice of proposed rulemaking (SNOPR). 81 FR 60784.
[3]Energy Conservation Standards for Consumer Conventional Cooking Products; Notice of proposed determination (NOPD). 85 FR 80982.
[4]Energy Conservation Standards for Consumer Conventional Cooking Products; SNOPR. 88 FR 6818.

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Residential Natural Gas Cooktops, Ovens, and Ranges

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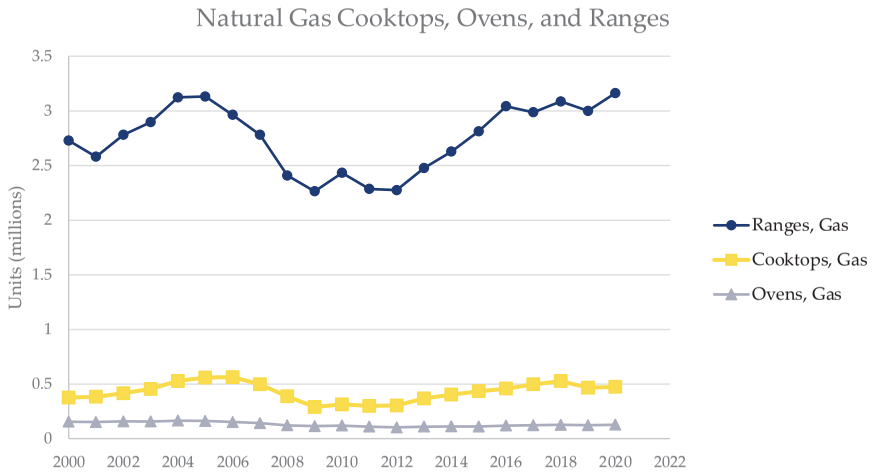
Shipments have been rising since 2012. In 2020, gas range shipments surpassed the peak reached in 2005.



Source: *Appliance Magazine and Consumer Cooking Products EERE 2022 SNOPR*

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Residential Electric Cooktops

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (W)	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700
Integrated Annual Energy Consumption (kWh/y)[1]	155	155	155	119	155	119	155	119	155	119
Average Life (y)	17	17	17	17	17	17	17	17	17	17
Retail Equipment Cost (2022$)[2]	470	470	470	810	470	810	470	810	470	810
Total Installed Cost (2022$)[2]	620	620	620	1,230	620	1,230	620	1,230	620	1,230
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to IAEC (kBtu/y). IAEC was determined using DOE rulemaking data for the most representative product class, electric smooth element cooking tops, which covers cooking tops with electric resistance heating elements and cooking tops with induction heating elements.
2. Equipment and installed costs are for cooktops only (not combined range units). Costs were determined using DOE rulemaking data for the most representative product class, electric smooth cooking tops, which includes cooking tops with electric resistance heating elements and cooking tops with induction heating elements. A high-end unit with induction technology is expected to have a greater retail equipment cost and greater installation cost in order to implement this technology.
3. Maintenance costs are negligible.

Note:
The range for typical capacity represents the span of typical values.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (16.88, 6.99).

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Residential Electric Ovens

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (W)	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400
Typical Cavity Volume (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kWh/y)[1]	355	355	355	278	355	278	355	278	355	278
Average Life (y)	17	17	17	17	17	17	17	17	17	17
Retail Equipment Cost (2022$)[2]	630	630	630	730	630	730	630	730	630	730
Total Installed Cost (2022$)[2]	770	770	770	870	770	870	770	870	770	870
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to IAEC (kBtu/y). IAEC was determined using DOE rulemaking data for freestanding electric self-clean ovens, which represent the majority of the market.
2. Equipment and installed costs are for ovens only (not combined ranges). Costs are reflective of freestanding self-clean oven units with single oven component, which represent the majority of the market.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (16.88, 6.99).

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Residential Electric Ranges

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DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity of Cooktop Component (W)	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700
Typical Capacity of Oven Component (W)	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400
Typical Cavity Volume of Oven Component (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kWh/y)[1]	510	510	510	397	510	397	510	397	510	397
Average Life (y)	17	17	17	17	17	17	17	17	17	17
Retail Equipment Cost (2022$) [2]	630	630	630	900	630	900	630	900	630	900
Total Installed Cost (2022$) [2]	770	770	770	1,050	770	1,050	770	1,050	770	1,050
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. IAEC of an electric range is calculated as the sum of the IAEC for an electric cooktop and an electric oven. IAEC of the electric cooktop component was determined using DOE rulemaking data for the most representative product class, electric smooth element cooking tops, which covers cooking tops with electric resistance heating elements and cooking tops with induction heating elements. IAEC of the electric oven component was determined using DOE rulemaking data for freestanding electric self-clean ovens, which represent the majority of the market.
2. Retail and installed cost are reflective of standard units that are 30-inch wide and have 4 to 5 cooking top heating elements. Based on data from DOE rulemakings, Gordian's RSMeans Data – Building Construction Costs 2023, and distributors, total installed cost is estimated to be around $140 more than retail equipment cost for a typical unit, and $150 more than retail equipment cost for a high-end unit. A high-end unit with an induction cooking top component is expected to have a greater retail equipment cost and greater installation cost in order to implement this technology.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (16.88, 6.99).

Residential Electric Cooktops, Ovens, and Ranges

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- DOE analyzes cooktops and ovens separately, although they are often sold together in a single unit that combines both a cooktop and an oven into a product referred to as a range.
- DOE initiated a standards rulemaking in 2014 to consider amended standards for cooking products, including electric cooktops and ovens[1].
- On September 2, 2016, DOE proposed performance-based standards for electric cooktops and ovens that would take effect in 2020 if adopted.
- DOE established the new IAEC metric, in kWh/y, to replace cooking efficiency (%).
- On December 14, 2020, DOE initially determined that amended energy conservation standards for consumer conventional cooking products would not be economically justified and would not result in a significant conservation of energy[2].
- On February 2, 2023, DOE proposed new and amended energy conservation standards for consumer conventional cooking products[3].
- The IAEC of a range is calculated as the sum of the IAECs for cooktops and ovens. However, retail and installation costs for a range are similar to the cost of an oven.

[1]Energy Conservation Standards for Residential Conventional Cooking Products; Supplemental notice of proposed rulemaking (SNOPR). 81 FR 60784.
[2]Energy Conservation Standards for Consumer Conventional Cooking Products; Notice of proposed determination (NOPD). 85 FR 80982.
[3]Energy Conservation Standards for Consumer Conventional Cooking Products; SNOPR. 88 FR 6818.

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Residential Electric Cooktops, Ovens, and Ranges

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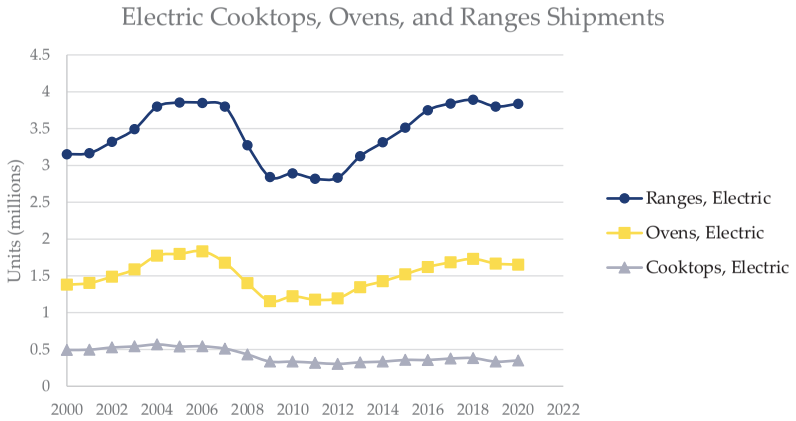
Shipments of electric cooking products reached a peak in 2006. Shipments of ranges and ovens have been rising again since 2012. In 2018, electric range shipments surpassed the peak reached in 2006.



Source: *Consumer Cooking Products EERE 2022 SNOPR*

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Residential Clothes Dryers (Electric)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1[1]	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	7.4	7.4	7.4	7.4	7.4	4.5	7.4	4.5	7.4	4.5	7.4	4.5
Combined Energy Factor, D1 (lb/kWh)[2]	3.59	3.73	3.73	3.73	NA	3.93	3.73	3.93	3.73	3.93	3.73	3.93
Combined Energy Factor, D2 (lb/kWh)[2]	3.59	3.93	3.73	3.93	3.93	11.00	3.93	11.00	3.93	11.00	3.93	11.00
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8	8
	18	18	18	18	18	18	18	18	18	18	18	18
Retail Equipment Cost (2022$)	580	580	580	580	580	980	580	980	580	980	580	980
Total Installed Cost (2022$)	710	710	710	710	710	1,110	710	1,110	710	1,110	710	1,110
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-	-	-

1. ENERGY STAR V. 1.1 applies to vented and ventless standard electric clothes dryers.
2. The efficiency metric changed from EF to combined energy factor (CEF) in 2015. The 2015 Installed Base CEF data accounts for units tested to appendix D1 and appendix D2, because data specific to each appendix is not available for that year.
3. Maintenance costs are negligible. DOE estimated that on average 2.7 percent of electric and 3.3 percent of gas residential clothes dryers are repaired each year. (EERE 2014)

Note:
DOE test procedures for consumer clothes dryers appear at title 10 of the Code of Federal Regulations part 430, subpart B, appendix D1 and appendix D2. The second test method, appendix D2, was finalized in a final rule published by DOE on August 14, 2013. For current standard testing, units must be tested according to either the appendix D1 or the appendix D2 test method. ENERGY STAR V. 1.1 requires certified units to be tested according to the appendix D2 test method. The appendix D1 and appendix D2 test methods determine CEF differently.
The current standard went into effect in January 2015.
ENERGY STAR V. 1.1 went into effect in May 2017.
The range for average life represents the span of typical values.

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Residential Clothes Dryers (Gas)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1[1]	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Combined Energy Factor, D1 (lb/kWh)[2]	3.18	3.30	3.30	3.30	NA	3.48	3.30	3.48	3.30	3.48	3.30	3.48
Combined Energy Factor, D2 (lb/kWh)[2]	3.18	3.48	3.30	3.48	3.48	3.50	3.48	3.50	3.48	3.50	3.48	3.50
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8	8
	18	18	18	18	18	18	18	18	18	18	18	18
Retail Equipment Cost (2022$)	660	670	660	670	670	670	670	670	670	670	670	670
Total Installed Cost (2022$)	860	870	870	870	870	870	870	870	870	870	870	870
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-	-	-

1. ENERGY STAR V. 1.1 applies to vented and ventless standard electric clothes dryers.
2. The efficiency metric changed from EF to CEF in 2015. The 2015 Installed Base CEF data accounts for units tested to appendix D1 and appendix D2, because data specific to each appendix is not available for that year.
3. Maintenance costs are negligible. DOE estimated that on average 2.7 percent of electric and 3.3 percent of gas residential clothes dryers are repaired each year. (EERE 2014)

Note:
DOE test procedures for consumer clothes dryers appear at title 10 of the Code of Federal Regulations part 430, subpart B, appendix D1 and appendix D2. The second test method, appendix D2, was finalized in a final rule published by DOE on August 14, 2013. For current standard testing, units must be tested according to either the appendix D1 or the appendix D2 test method. ENERGY STAR V. 1.1 requires certified units to be tested according to the appendix D2 test method. The appendix D1 and appendix D2 test methods determine CEF differently.
The current standard went into effect in January 2015.
ENERGY STAR V. 1.1 went into effect in May 2017.
The range for average life represents the span of typical values.

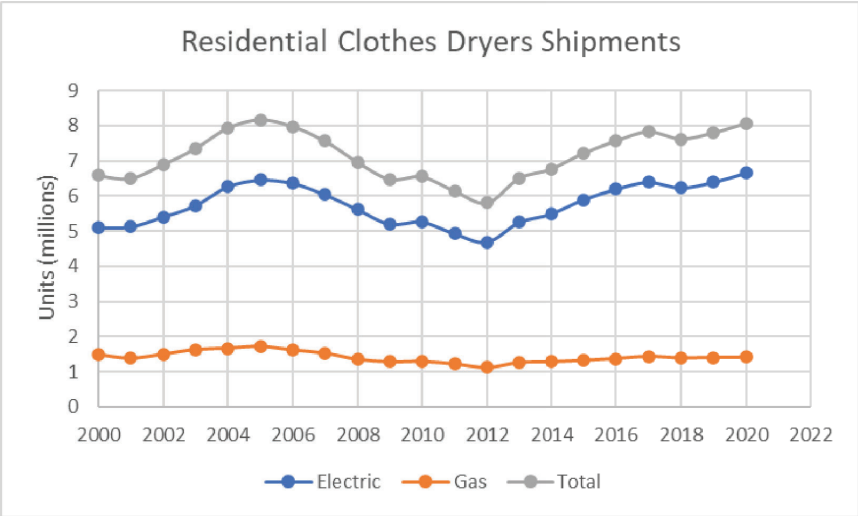
Residential Clothes Dryers

- Current standards[1] in effect since 2015:
  - For standard-size electric units : CEF ≥ 3.73 pound per kilowatt hours (lb/kWh)
  - For gas units: CEF ≥ 2.30 lb/kWh
  - Units may be tested according to the test method in appendix D1 or appendix D2, which was finalized in 2013.
- The main differences between appendix D1 and appendix D2 are:
  - Appendix D2 includes test methods that more accurately measure the effects of automatic cycle termination and that may result in differences in the total measured energy consumption of the test cycle as compared to the test methods in appendix D1.
  - Appendix D2 contains instructions for the testing of timer dryers, which include a lower final moisture content (FMC) of the test load as compared to the version of appendix D1 used for the 2011 rulemaking analysis.
- Efficiency improvement technologies for clothes dryers include:
  - Multi-step or modulating heat
  - Higher efficiency drum motors
  - Inlet air pre-heat
  - Better control systems for cycle termination
  - Heat pump (for electric clothes dryers)
- EPA developed ENERGY STAR V. 1.1, which became effective in 2017 and requires units to be tested according to the test method in appendix D2.
- Standard-size heat pump clothes dryers with CEF values up to 11.0 are currently available in the U.S. market. High initial cost has limited market penetration, but some utilities are offering rebates to support market penetration.

[1]Energy Conservation Standards for Consumer Clothes Dryers. 10 CFR 430.32(h).

Residential Clothes Dryers

Shipment volumes have been on the rise since 2012. Gas dryers continue to account for about one-fifth of the market.



Source: *Consumer Clothes Dryers EERE 2022 NOPR*

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Residential Clothes Washers (Front)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	3.7	4.1	3.4	4.5	4.5	5.0	4.5	5.0	4.5	5.0	4.5	5.0
Integrated Modified Energy Factor (ft^3/kWh/cycle)[1]	2.16	2.76	1.84	2.76	2.76	3.10	2.76	3.10	2.76	3.10	2.76	3.10
Integrated Water Factor (gal/cycle/ft^3)[2]	4.7	3.2	4.7	3.2	3.2	2.7	3.2	2.7	3.2	2.7	3.2	2.7
Average Life (y)	6	6	6	6	6	6	6	6	6	6	6	6
	17	17	17	17	17	17	17	17	17	17	17	17
Water Consumption (gal/cycle)	17	14	16	14	14	14	14	14	14	14	14	14
Hot Water Energy (kWh/cycle)	0.21	0.17	0.36	0.12	0.12	0.13	0.12	0.13	0.12	0.13	0.12	0.13
Machine Energy (kWh/cycle)	0.17	0.14	0.15	0.12	0.12	0.17	0.12	0.17	0.12	0.17	0.12	0.17
Dryer Energy (kWh/cycle)	1.31	1.24	1.34	1.17	1.17	1.56	1.17	1.56	1.17	1.56	1.17	1.56
Retail Equipment Cost (2022$)	735	1,000	705	930	930	950	930	950	930	950	930	950
Total Installed Cost (2022$)	915	1,175	880	1,130	1,130	1,150	1,130	1,150	1,130	1,150	1,130	1,150
Annual Maintenance Cost (2022$)	15	15	15	15	15	15	15	15	15	15	15	15

1. The efficiency metric changed from Modified Energy Factor to Integrated Modified Energy Factor (IMEF) in 2015.
2. The efficiency metric changed from Water Factor to Integrated Water Factor (IWF) in 2015.

Note:
The current standard went into effect in January 2018.
ENERGY STAR V. 8.1 went into effect in February 2018.
The range for average life represents the span of typical values.

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Residential Clothes Washers (Top)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	3.3	3.4	3.5	3.5	4.4	5.5	3.5	5.5	3.5	5.5	3.5	5.5
Integrated Modified Energy Factor (ft^3/kWh/cycle)[1]	1.14	1.57	1.57	1.57	2.06	2.76	1.57	2.76	1.57	2.76	1.57	2.76
Integrated Water Factor (gal/cycle/ft^3)[2]	9.2	6.5	6.5	6.5	4.3	3.2	6.5	3.2	6.5	3.2	6.5	3.2
Average Life (y)	6	6	6	6	6	6	6	6	6	6	6	6
	17	17	17	17	17	17	17	17	17	17	17	17
Water Consumption (gal/cycle)	30	22	23	23	19	18	23	18	23	18	23	18
Hot Water Energy (kWh/cycle)	0.90	0.39	0.41	0.41	0.38	0.24	0.41	0.24	0.41	0.24	0.41	0.24
Machine Energy (kWh/cycle)	0.25	0.13	0.14	0.14	0.12	0.13	0.14	0.13	0.14	0.13	0.14	0.13
Dryer Energy (kWh/cycle)	1.73	1.63	1.68	1.68	1.64	1.61	1.68	1.61	1.68	1.61	1.68	1.61
Retail Equipment Cost (2022$)	590	590	520	520	640	725	520	725	520	725	520	725
Total Installed Cost (2022$)	765	765	715	715	840	920	715	920	715	920	715	920
Annual Maintenance Cost (2022$)	15	15	15	15	15	15	15	15	15	15	15	15

1. The efficiency metric changed from Modified Energy Factor to IMEF in 2015.
2. The efficiency metric changed from Water Factor to IWF in 2015.

Note:
The current standard went into effect in January 2018.
ENERGY STAR V. 8.1 went into effect in February 2018.
The range for average life represents the span of typical values.

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Residential Clothes Washers

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- The analysis treats front- and top-loading models separately due to their different energy use characteristics.
- Federal standards[1] for standard-capacity clothes washers (≥ 1.6 ft^3):

	Integrated Modified Energy Factor		Integrated Water Factor	
	Top-Loading	Front-Loading	Top-Loading	Front-Loading
Current DOE Standard (effective 1/1/2018)	≥ 1.57	≥ 1.84	≤ 6.5	≤ 4.7
Current ENERGY STAR V. 8.1 (effective 4/22/2021)	≥ 2.06	≥ 2.76	≤ 4.3	≤ 3.2

- In 2020, about 40% of top-loading models and almost all front-loading models achieved the ENERGY STAR level.
- Energy efficiency improvement technologies for clothes washers include:
  - Higher efficiency motors and higher spin speeds
  - Better load sensing for adaptive water fill control
  - Reduced water temperature and quantity, while providing equivalent cleaning and rinsing performance
- Maintenance costs include replacement or repair of the drain pump, control board, motor, rubber gaskets, or control panel knobs.
- The products on the market with the highest IMEF have significantly larger capacity and therefore use more energy per cycle than typical, smaller capacity products but still perform more efficiently on a per volume basis.

[1]Energy Conservation Standards for Consumer Clothes Washers. 10 CFR 430.32(g).

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Residential Clothes Washers

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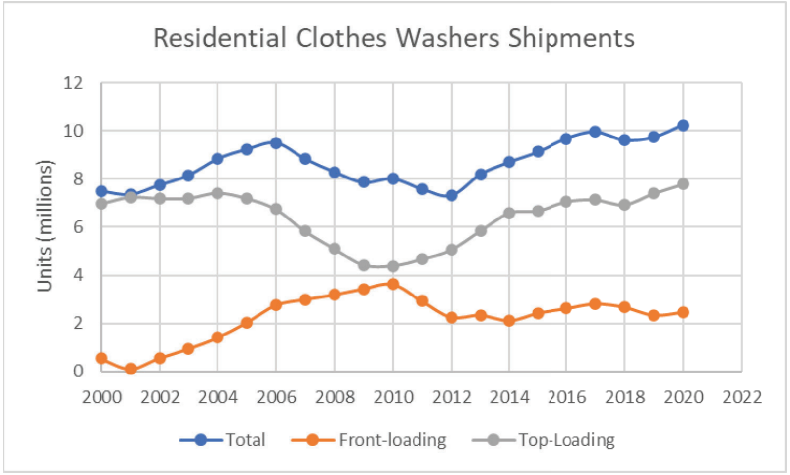
Shipments have been on the rise since 2012 and reached a peak of about 10 million in 2020. Since 2012, top-loading and front-loading units represent approximately 75% and 25% of shipments, respectively.



Source: *AHAM Shipment Data; RCW EERE 2021 Preliminary Analysis*

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Residential Dishwashers

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DATA	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 6.0	High	ENERGY STAR V. 7.0	Typical	High	Typical	High	Typical	High
Typical Annual Energy Use (kWh/y)	295	270	307	270	270	225	240	240	225	240	225	240	225
Water Consumption (gal/cycle)	4.25	3.50	5.00	3.50	3.50	2.40	3.20	3.20	2.40	3.20	2.40	3.20	2.40
Water Heating Energy Use (kWh/y)[1]	154	125	176	123	123	84	112	123	84	123	84	123	84
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	440	380	310	340	340	500	430	340	500	340	500	340	500
Total Installed Cost (2022$)	840	570	490	520	520	690	610	520	690	520	690	520	690
Annual Maintenance Cost (2022$)[2]	-	-	-	-	-	-	-	-	-	-	-	-	-

1. Refers to that portion of "Typical Annual Energy Use" that is the energy used to heat water in a separate water heater before it enters the dishwasher. The energy used to heat water inside the dishwasher cannot be disaggregated from the total.
2. Maintenance costs are negligible.

Note:
All values in table reflect 215 cycles/year according to the current test procedure at 10 CFR 430 Appendix C1.
The current standard went into effect in May 2013.
ENERGY STAR V. 6.0 went into effect in January 2016.
ENERGY STAR V. 7.0 will go into effect in July 2023.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.9, 1.8, 1).

Residential Dishwashers

- Performance criteria for standard-capacity dishwashers (assumes 215 cycles/year):
  - Federal Standards:
    - May 30, 2013: ≤ 307 kWh/y, ≤ 5.0 gal/cycle (DOE Direct Final Rule, published May 2012)
  - ENERGY STAR Criteria:
    - Jan. 29, 2016: ≤ 270 kWh/y (5% allowance for connected), ≤ 3.5 gal/cycle (V. 6.0)
    - July 19, 2023: ≤ 240 kWh/y, ≤ 3.2 gal/cycle (V. 7.0, effective August 2023)
- ENERGY STAR has maintained a very high market share for several years (93% in 2021), so sales-weighted average efficiency has tracked ENERGY STAR levels.
  - Due to the historically high market penetration of ENERGY STAR products, it is expected that manufacturers will make the necessary adjustments so ENERGY STAR V. 7.0 levels will be typical in future projections.
- Test procedures:
  - Accounts for motor, dryer, booster heater (if present), and hot water from separate water heater, as well as standby and off-mode energy.
  - ENERGY STAR established a cleaning performance test method. While cleaning performance reporting is currently optional, V. 7.0 requires a cleaning index of 65 or higher for ENERGY STAR certification.
  - In January 2023, DOE established a test procedure at Appendix C2, which would go into effect at the time of any amended energy conservation standards. Appendix C2 establishes a minimum cleaning index threshold of 70 as a condition for a valid test cycle. The cleaning index threshold of 70 established by DOE is equivalent to the cleaning index threshold of 65 specified in ENERGY STAR V. 7.0.
- Efficiency improvement technologies for dishwashers include:
  - Better soil sensing
  - Control strategies
  - Water distribution (small pipes, fine filter, small sump, multiple spray arms, alternating water use) and controls (flow meter, temperature sensor)
  - Inline water heater (to minimize sump volume)
  - Separate drain pump, high-efficiency, variable-speed circulation pump motor
  - Condensation drying (rather than power dry)

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Residential Dishwashers

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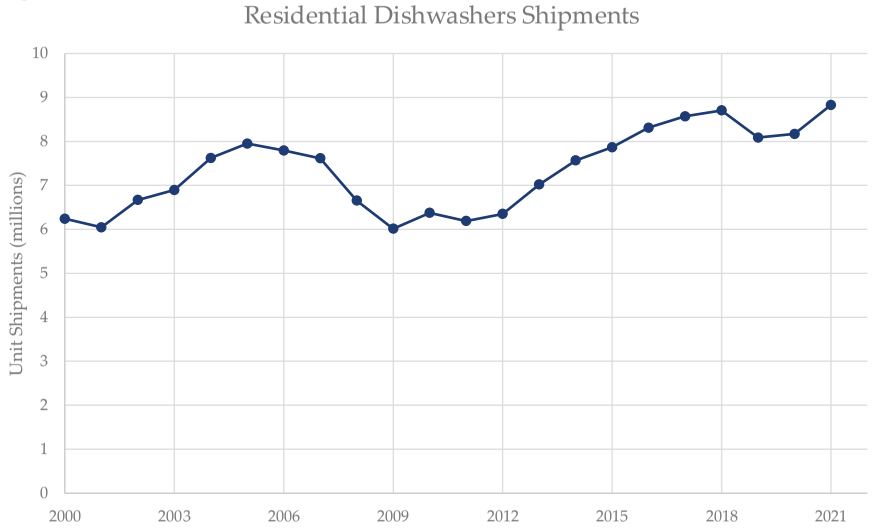
Shipments increased steadily from the early 1990s until the 2008-2009 recession. Shipments have resumed similar growth since then.



Source: *DW EERE 2022 Preliminary Analysis*

Commercial Space Heating and Cooling

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Commercial Gas-Fired Furnaces

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DATA	2012	2018	2022			2023[1]		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	Typical	Typical	Typical
Typical Input Capacity (kBtu/h)[2]	400	400	250	250	250	250	250	250	250	250
Thermal Efficiency (%)[3]	80	80	80	81	81	81	81	81	81	81
Typical Output Capacity (kBtu/h)	320	320	200	203	203	203	203	203	203	203
Average Life (y)	23	23	23	23	23	23	23	23	23	23
Retail Equipment Cost (2022$)	1,230	1,230	1,230	1,260	1,260	1,260	1,260	1,260	1,260	1,260
Total Installed Cost (2022$)	2,540	2,540	2,540	2,580	2,580	2,580	2,580	2,580	2,580	2,580
Total Installed Cost (2022$/kBtu/h)	8	8	13	13	13	13	13	13	13	13
Annual Maintenance Cost (2022$)	200	200	200	200	200	200	200	200	200	200
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1	1	1	1

1. In 2023, the new Energy Conservation Standards for Commercial Warm Air Furnaces (CWAF) took effect. These projections reflect the 2023 minimum thermal efficiency requirement for gas-fired furnaces, 81%.
2. When this analysis was previously conducted in EIA Technology Forecast Updates (2018), a typical input capacity of 400 kBtu/h was listed. An updated typical input capacity value of 250 kBtu/h was determined through an evaluation of the units in the DOE CCD as of August 2022. CWAF EERE 2015 also listed a representative input capacity of 250 kBtu/h.
3. DOE's efficiency metric for commercial furnaces accounts only for flue losses, not jacket losses.

Note:
The previous standard went into effect in January 1994. The current standard went into effect in January 2023.

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Commercial Gas-Fired Furnaces

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- Until 2022, the Federal standard required minimum 80% thermal efficiency. This metric, more commonly called "combustion efficiency" in other contexts, accounts only for flue losses, not jacket losses.
  - The Federal standard applied to all units manufactured on or after January 1, 1994, with maximum rated heat input ≥ 225,000 Btu per hour.
  - On January 1, 2023, the minimum Federal standard increased to 81% thermal efficiency.
- ASHRAE Standard 90.1, which is used as a commercial building code in many states, stipulates that furnaces that are not within the conditioned space shall not have jacket losses exceeding 0.75% of the input rating.
- Commercial furnaces are typically non-condensing with thermal efficiencies ranging from 80% to 81%. Condensing commercial furnaces, which can achieve up to 95% thermal efficiency, were previously introduced to the market but are not currently available due to cost and reliability concerns. The highest thermal efficiency included in DOE's CCD at this time is 81%.
- Besides capacity, commercial units can differ from residential furnaces in terms of the control system (i.e., integration with a Building Management System, twinning, or other staging strategies). Commercial systems may also use a heat recovery system to pre-heat inlet air.

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Commercial Gas-Fired Furnaces

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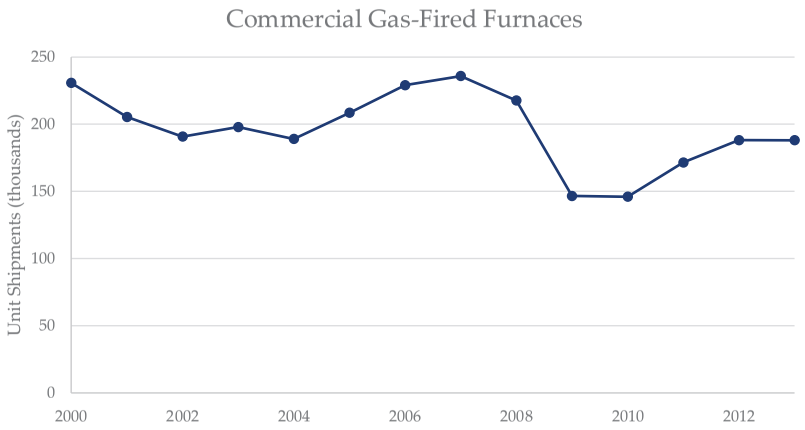
Annual shipments reached a peak of 235.9 thousand units in 2007. Following a decline in shipments after 2007, shipments increased to 188.1 thousand units in 2013. Shipment data after 2013 is not available.



Source: *AHRI*

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Commercial Oil-Fired Furnaces

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DATA	2012	2018	2022			2023[1]	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	400	400	250	250	250	250	250	250	250	250	250	250
Thermal Efficiency (%)[2]	81	82	81	82	85	82	82	85	82	85	82	85
Typical Output Capacity (kBtu/h)	324	328	203	205	213	205	205	213	205	213	205	213
Average Life (y)	23	23	23	23	23	23	23	23	23	23	23	23
Retail Equipment Cost (2022$)	5,500	5,560	5,500	5,560	6,020	5,560	5,560	6,020	5,560	6,020	5,560	6,020
Total Installed Cost (2022$)	7,740	7,810	7,740	7,810	8,380	7,810	7,810	8,380	7,810	8,380	7,810	8,380
Total Installed Cost (2022$/kBtu/h)	24	24	38	38	39	38	38	39	38	39	38	39
Annual Maintenance Cost (2022$)	360	360	360	360	370	360	360	370	360	370	360	370
Annual Maintenance Cost (2022$/kBtu/h)	1	1	2	2	2	2	2	2	2	2	2	2

1. In 2023, the new Energy Conservation Standards for CWAF took effect. These projections reflect the 2023 minimum thermal efficiency requirement for oil-fired furnaces, 82%.
2. DOE's efficiency metric for commercial furnaces accounts only for flue losses, not jacket losses.

Note:
The previous standard went into effect in January 1994. The current standard went into effect in January 2023.

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Commercial Oil-Fired Furnaces

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- Until 2022, the Federal standard required minimum 81% thermal efficiency. This metric, more commonly called "combustion efficiency" in other contexts, accounts only for flue losses, not jacket losses.
  - The Federal standard applied to all units manufactured on or after January 1, 1994, with maximum rated heat input ≥ 225,000 Btu per hour.
  - On January 1, 2023, the minimum Federal standard increased to 82% thermal efficiency.
- ASHRAE Standard 90.1, which is used as a commercial building code in many states, stipulates that furnaces that are not within the conditioned space shall not have jacket losses exceeding 0.75% of the input rating.
- Commercial oil-fired furnaces have thermal efficiencies ranging from 81% to 85% and are non-condensing (i.e., not designed for condensation of flue gases).
- Besides capacity, commercial units can differ in terms of the control system (i.e., integration with a Building Management System, twinning, or other staging strategies). Commercial systems may also use a heat recovery system to pre-heat inlet air.
- The maintenance cost estimate assumes two cleanings per year.

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Commercial Oil-Fired Furnaces

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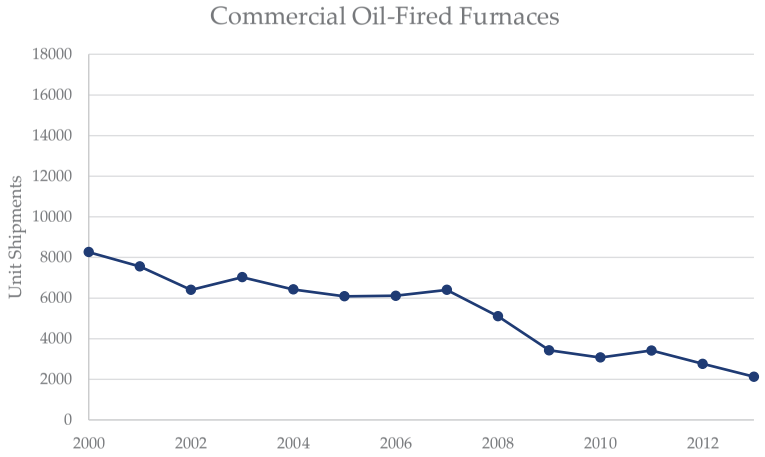
Annual shipments for commercial oil-fired furnaces have steadily decreased over time to 2,127 units in 2013. Shipment data after 2013 is not available.



Source: *AHRI*

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Commercial Electric Resistance Heaters

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DATA	2012		2018		2022		2030		2040		2050	
	Installed Base: Small	Installed Base: Large	Installed Base: Small	Installed Base: Large	Small	Large	Small	Large	Small	Large	Small	Large
Typical Capacity (kBtu/h)[1]	17	170	17	170	17	170	17	170	17	170	17	170
Efficiency (%)	100	100	100	100	100	100	100	100	100	100	100	100
Average Life (y)	18	18	18	18	18	18	18	18	18	18	18	18
Retail Equipment Cost (2022$)	1,000	6,320	1,000	6,320	500	4,630	500	4,630	500	4,630	500	4,630
Total Installed Cost (2022$)	1,240	7,470	1,240	7,470	660	5,470	660	5,470	660	5,470	660	5,470
Total Installed Cost (2022$/kBtu/h)	73	44	73	44	39	32	39	32	39	32	39	32
Annual Maintenance Cost (2022$)[2]	-	-	-	-	-	-	-	-	-	-	-	-
Annual Maintenance Cost (2022$/kBtu/h)	-	-	-	-	-	-	-	-	-	-	-	-

1. Capacity is output.
2. Annual Maintenance Cost is negligible.

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Commercial Electric Resistance Heaters

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- This analysis examined standard suspended electric wall and ceiling unit heaters, which are more common in commercial settings than baseboard electric heaters that were considered for the residential analysis.
- Electric unit heaters range in capacity from 2 to 80 kW (7 to 270 kBtu/h), with 5 to 50 kW (17 to 170 kBtu/h) being the most typical units on the market.
- Electric resistance heaters are considered near 100% efficient because there is no heat loss through ducts or combustion.
- Installation time and costs are estimated to be minimal.

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Commercial Electric Boilers

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DATA	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (kW)[1]	165	165	165	165	165	165
Efficiency (%)	98	98	98	98	98	98
Average Life (y)	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	11,620	11,590	9,790	9,790	9,790	9,790
Total Installed Cost (2022$)[2]	17,500	13,820	11,950	11,950	11,950	11,950
Total Installed Cost (2022$/kBtu/h)	31	25	21	21	21	21
Annual Maintenance Cost (2022$)[2]	170	130	130	130	130	130
Annual Maintenance Cost (2022$/kBtu/h)	-	-	-	-	-	-

1. Capacity is output.
2. Retail and installed costs for 2022 and forecasts for 2030 and beyond are based on Gordian's RSMeans Data – Building Construction Costs 2023. Maintenance costs are same as EIA Technology Forecast Updates (2018), updated to reflect 2022$. The costs shown are for one 165kW unit, which would equate to a steady load of approximately 550,000 Btu/h. Annual maintenance in a typical application would include draining the unit for removal of any accumulated scale or sludge buildup.

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Commercial Electric Boilers

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- There are currently no federal standards associated with electric boilers.
- The costs shown are for one 165kW unit, which would equate to a steady load of approximately 550,000 Btu/h.
- Service life is determined mainly by water quality. Water conditioning (e.g., filters, softeners, de-alkalizers, chemical feeders) may be necessary for a given application.
- Annual maintenance in a typical application would include draining the unit for removal of any accumulated scale or sludge buildup.
- Minor end-use inefficiencies for electric boilers result from heat loss through the boiler (jacket losses).

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Commercial Gas-Fired Boilers

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DATA	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard[1]	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Thermal Efficiency (%)[2]	77	85	80	85	99	84	85	99	85	99	85	99	85	99
Average Life (y)	30	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	15,530	25,910	19,150	25,910	42,670	24,320	25,910	42,670	25,910	42,670	25,910	42,670	25,910	42,670
Total Installed Cost (2022$)	24,600	38,330	30,470	38,330	55,230	35,650	38,330	55,230	38,330	55,230	38,330	55,230	38,330	55,230
Total Installed Cost (2022$/kBtu/h)	40	56	48	56	70	53	56	70	56	70	56	70	56	70
Annual Maintenance Cost (2022$)[3]	1,710	2,100	2,100	2,100	2,140	2,100	2,100	2,140	2,100	2,140	2,100	2,140	2,100	2,140
Annual Maintenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3	3	3	3

1. The standard level shown here is for small (300 kBtu/h to 2500 kBtu/h) gas-fired hot water commercial packaged boilers, which are the most common type of boilers available on the market.
2. DOE's efficiency metric for most boiler types accounts for both flue and jacket losses; previously it did not. DOE continues to uses a combustion efficiency metric instead, for hot water boilers with heat input > 2,500,000 Btu/h.
3. Maintenance costs for 2018 and post-2018 are based on Commercial Packaged Boilers EERE 2020. The annualized maintenance costs estimated in the final rule differ for condensing vs. non-condensing boilers. Appendix 8E of the Commercial Packaged Boilers EERE 2020 TSD provides additional information on how the values are calculated.

Note:
The previous standard went into effect in March 2012.
The current standard went into effect in January 2023.
In December 2016, DOE issued a final rule titled Energy Conservation Program: Energy Conservation Standards for Commercial Packaged Boilers. This rule published in January 2020 with an effective date for January 2023.

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Commercial Gas-Fired Boilers

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- Commercial packaged gas-fired boilers are classified by:
  - Heat input capacity
  - Produce steam or hot water
  - Draft type (natural draft or not) – for steam boilers
- The most common type of commercial gas-fired boilers are small gas-fired hot water boilers with 300,000-2,500,000 Btu/h rated heat input.
- Similar technologies to those used in the residential gas-fired boilers market can be leveraged in the commercial arena. The higher efficiency units typically include electronic ignition, power burners, and improved heat exchangers. Some gas-fired boilers also condense water vapor from the flue gases to improve heating efficiency.
- DOE published a final rule for commercial packaged boilers in January 2020 that updated the efficiency ratings of gas-fired commercial packaged boilers beginning January 2023.

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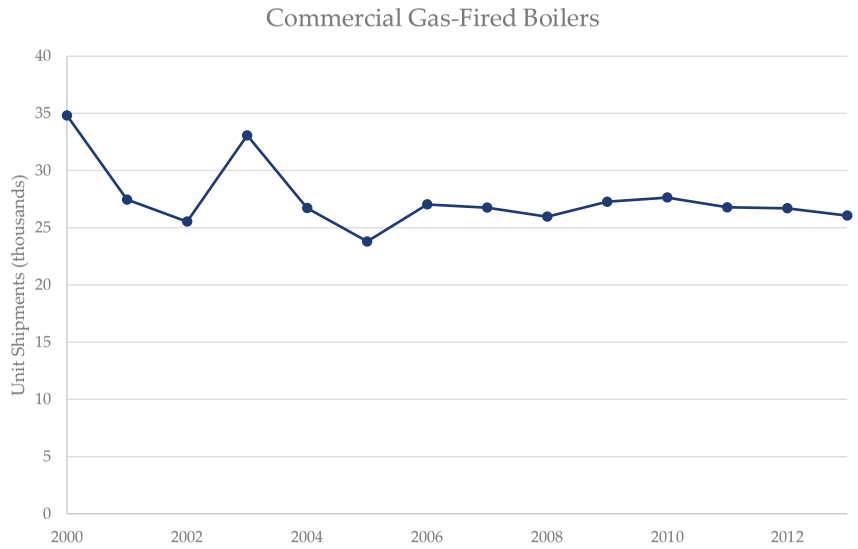
Shipments of commercial gas-fired boilers peaked in 2000 and have been steadily declining since 2010. Shipment data after 2013 is not available.



Source: *Commercial Packaged Boilers EERE 2020*

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Commercial Oil-Fired Boilers

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DATA	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard[1]	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	1,200	800	800	800	800	800	800	800	800	800	800	800	800	800
Thermal Efficiency (%)[2]	81	85	82	85	97	87	87	97	87	97	87	97	87	97
Average Life (y)	30	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	16,830	26,810	23,190	26,810	51,480	29,730	29,730	51,480	29,730	51,480	29,730	51,480	29,730	51,480
Total Installed Cost (2022$)	22,000	37,240	33,100	37,240	62,910	40,160	40,160	62,910	40,160	62,910	40,160	62,910	40,160	62,910
Total Installed Cost (2022$/kBtu/h)	23	55	50	55	81	58	58	81	58	81	58	81	58	81
Annual Maintenance Cost (2022$)[3]	1,710	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690
Annual Maintenance Cost (2022$/kBtu/h)	2	4	4	4	3	4	4	3	4	3	4	3	4	3

1. The standard level shown here is for small (300 kBtu/h to 2500 kBtu/h) oil-fired hot water commercial packaged boilers, which are the most common type of boilers available on the market.
2. DOE's efficiency metric for most boiler types accounts for both flue and jacket losses; previously it did not. DOE continues to uses a combustion efficiency metric instead, for hot water boilers with heat input > 2,500,000 Btu/h.
3. Maintenance costs for 2018 and post-2018 are based on Commercial Packaged Boilers EERE 2020. The annualized maintenance costs estimated in the final rule differ for condensing vs. non-condensing boilers. Appendix 8E of the Commercial Packaged Boilers EERE 2020 TSD provides additional information on how the values are calculated.

Note:
The previous standard went into effect in March 2012.
The current standard went into effect in January 2023.
In December 2016, DOE issued a final rule titled Energy Conservation Program: Energy Conservation Standards for Commercial Packaged Boilers. This rule published in January 2020 with an effective date for January 2023.

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Commercial Oil-Fired Boilers

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- Commercial packaged oil-fired boilers are classified by:
  - Heat input capacity
  - Produce steam or hot water
- The most common type of commercial oil-fired boilers are small hot water boilers with 300,000-2,500,000 Btu/h rated heat input.
- The higher efficiency units typically include improved heat exchangers, and multi-step or variable-output power burners.
- DOE published a final rule for commercial packaged boilers in January 2020 that updated the efficiency ratings of oil-fired commercial packaged boilers beginning January 2023.

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Commercial Oil-Fired Boilers

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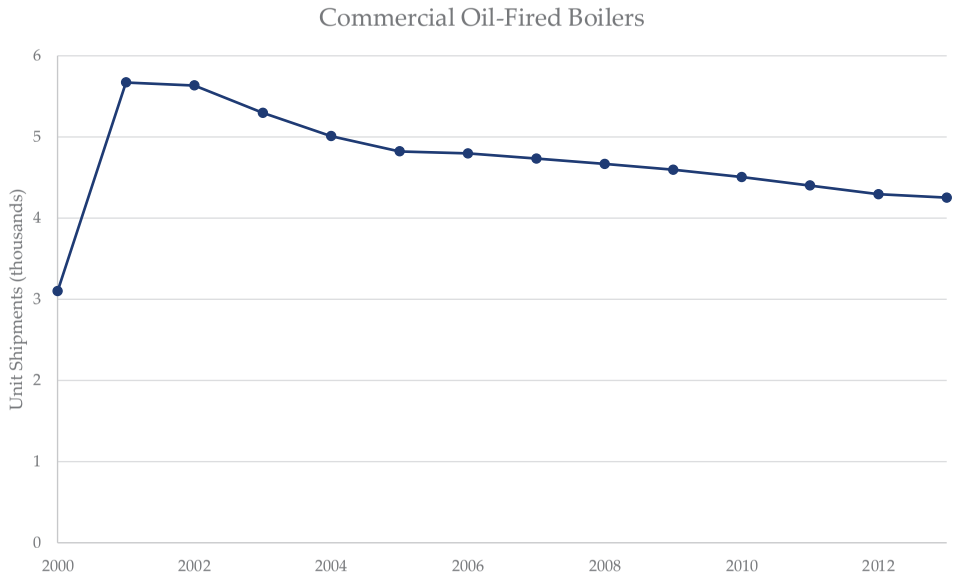
Shipments of commercial oil-fired boilers peaked in 2001 and have been decreasing since then.



Source: *Commercial Packaged Boilers EERE 2020*

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Commercial Centrifugal Chillers (Water-Cooled)

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DATA	2012	2018	2022[2]			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)[1]	400	400	400	400	400	400	400	400	400	400	400
	600	600	600	600	600	600	600	600	600	600	600
Efficiency [full-load] (kW/ton)	0.66	0.53	0.56	0.52	0.45	0.49	0.42	0.46	0.41	0.45	0.40
Efficiency [IPLV] (kW/ton)	0.61	0.37	0.50	0.31	0.30	0.30	0.28	0.29	0.26	0.28	0.25
COP [full-load]	5.4	6.6	6.3	6.8	7.8	7.2	8.4	7.6	8.6	7.8	8.8
COP [IPLV]	5.9	9.5	7.0	11.3	11.7	11.7	12.6	12.1	13.5	12.6	14.1
Average Life (y)	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$/ton)	380	500	480	500	680	590	760	660	780	690	810
Total Installed Cost (2022$/ton)	440	560	480	560	740	640	820	720	840	740	870
	500	590	540	590	760	670	830	740	860	760	880
Total Installed Cost (2022$/kBtu/h)	39	48	43	48	63	55	69	61	71	63	73
Annual Maintenance Cost (2022$/ton)	30	30	30	30	30	30	30	30	30	30	30
	40	40	40	40	40	40	40	40	40	40	40
Annual Maitnenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3

1. Capacity is output.
2. ASHRAE 90.1 data are for units larger than 400 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019). Typical and high efficiency levels are determined based on the range of products currently available on the market.

Note:

For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the integrated part-load value (IPLV)) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.

ASHRAE 90.1 went into effect in October 2019.

Ranges represent the span of typical values for a given parameter.

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Commercial Centrifugal Chillers (Water-Cooled)

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- ASHRAE 90.1-2019 stipulates minimum efficiencies for centrifugal chillers separately from positive displacement water-cooled chillers. They are separated into 5 size categories, with categories divided at: 150, 300, 400, and 600 tons; ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly high full-load consumption in exchange for much lower part-load consumption. For example, for a 600-ton unit:
  - Path A: ≥ 0.56 kW/ton full-load and ≥ 0.50 kW/ton IPLV
  - Path B: ≥ 0.585 kW/ton full-load and ≥ 38 kW/ton IPLV
- Federal Energy Management Program (FEMP) recommendations, last updated in 2020, match ASHRAE 90.1-2019.
- The highest efficiency centrifugal chillers incorporate some of the following:
  - Variable speed drive (VSD) compressors
  - Dedicated heat recovery (heat pump chiller)
  - Magnetic bearing technology (oil-free operation)
  - Greater heat exchanger surface areas; enhanced tube configurations (counterflow)
  - Optimized fluid flow velocities
  - High efficiency electric motors
  - Improved turbomachinery design, resulting in higher compressor efficiency
  - Better piping and valving, including electronic expansion valves
  - Evaporative condenser for the heat rejection equipment
- Installed costs vary widely depending on equipment needed for installation (e.g., crane) and size of system. This is a mature market with centrifugal chillers representing 75% of commercial chiller sales larger than 200 tons.
- Water-cooled chiller ratings do not include energy consumption of the cooling tower and therefore are not directly comparable to rating for air-cooled chillers. Water-cooled centrifugal chillers were selected for analysis due to a higher model share on the AHRI directory in comparison to air-cooled chillers.

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Commercial Reciprocating Chillers (Air-Cooled Only)

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DATA	2012	2018	2022[2]			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019[3]	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)[1]	100	100	100	100	100	100	100	100	100	100	100
	200	200	200	200	200	200	200	200	200	200	200
Efficiency [full-load] (kW/ton)	1.26	1.19	1.19	1.15	1.00	1.15	1.00	1.15	1.00	1.15	1.00
Efficiency [IPLV] (kW/ton)	1.13	0.86	0.86	0.86	0.80	0.80	0.79	0.80	0.79	0.80	0.79
COP [full-load]	2.8	3.0	3.0	3.0	3.5	3.1	3.5	3.1	3.5	3.1	3.5
COP [IPLV]	3.1	4.1	4.1	4.1	4.5	4.4	4.5	4.4	4.5	4.4	4.5
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$/ton)	725	820	820	820	1,030	820	1,030	820	1,030	820	1,030
	600	730	730	730	880	730	880	730	880	730	880
Total Installed Cost (2022$/ton)	800	880	880	880	1,180	880	1,180	880	1,180	880	1,180
	700	760	760	760	1,090	760	1,090	760	1,090	760	1,090
Total Installed Cost (2022$/kBtu/h)	63	68	68	68	95	68	95	68	95	68	95
Annual Maintenance Cost (2022$/ton)	45	45	50	50	50	45	50	45	50	45	50
	25	25	30	30	30	25	30	25	30	25	30
Annual Maintenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3

1. Capacity is output.
2. ASHRAE 90.1 data are for units larger than 150 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019). Typical and high efficiency levels are determined based on the range of products currently available on the market.

Note:

This analysis covers air-cooled chillers only.

For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.

ASHRAE 90.1 went into effect in October 2019.

Ranges represent the span of typical values for a given parameter.

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Commercial Reciprocating Chillers (Air-Cooled Only)

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- Reciprocating chillers are most cost effective for small loads (30 to 150-ton range). However, reciprocating chiller market share continues to be supplanted by screw and scroll chillers. This trend has accelerated with the phase out of R-22, which was the refrigerant of choice for reciprocating products, which has in turn driven major manufacturers to replace their reciprocating product lines with scroll products (rather than redesign reciprocating products for new refrigerants). As a result, product options are very limited.
- Reciprocating chillers can be used in either air-cooled or water-cooled applications. Reciprocating chillers shown in the data are air-cooled. Air-cooled chillers are less efficient than the water-cooled models. Listed efficiencies include matched condensers and their associated energy use.
- ASHRAE 90.1-2019 stipulates minimum efficiencies for all air-cooled chillers together, including reciprocating chillers, while water-cooled chillers are separated by positive displacement (e.g., reciprocating) versus centrifugal models. Air-cooled chiller efficiencies are further split by size for more and less than 150 tons. ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly lower full-load efficiency in exchange for much higher part-load efficiency. For example, for a 100-ton unit:
  - Path A: ≥ 10.1 EER full-load and ≥ 13.7 IPLV EER
  - Path B: ≥ 9.7 EER full-load and ≥ 15.8 IPLV EER
- FEMP (2022) recommendations for air-cooled chillers are:
  - Path A (<150 tons): ≥ 10.89 EER full-load and ≥ 13.7 IPLV EER
  - Path B (<150 tons): ≥ 9.7 EER full-load and ≥ 16.86 IPLV EER (same as 90.1-2019)
- The highest efficiency reciprocating chillers incorporate some of the following:
  - Multiple compressors for staged capacity control
  - Improved heat-exchangers

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Commercial Screw Chillers (Air-Cooled Only)

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DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019[1]	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	100	100	100	100	100	100	100	100	100	100	100
	300	300	300	300	300	300	300	300	300	300	300
Efficiency [full-load] (kW/ton)	1.26	1.18	1.19	1.15	0.92	1.13	0.91	1.04	0.86	0.98	0.81
Efficiency [IPLV] (kW/ton)	1.13	0.84	0.86	0.81	0.55	0.79	0.53	0.72	0.49	0.68	0.45
COP [full-load]	2.8	3.0	3.0	3.1	3.8	3.1	3.9	3.4	4.1	3.6	4.3
COP [IPLV]	3.1	4.2	4.1	4.4	6.4	4.5	6.6	4.9	7.2	5.2	7.8
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$/ton)	760	970	1,130	1,130	1,230	1,140	1,230	1,180	1,250	1,200	1,270
	620	850	770	770	870	780	870	820	890	840	910
Total Installed Cost (2022$/ton)	910	1,150	1,250	1,250	1,350	1,260	1,350	1,300	1,370	1,320	1,390
	850	940	820	820	920	830	920	870	940	890	960
Total Installed Cost (2022$/kBtu/h)	73	87	86	86	95	87	95	90	96	92	98
Annual Maintenance Cost (2022$/ton)	50	50	50	50	50	50	50	50	50	50	50
	20	20	20	20	20	20	20	20	20	20	20
Annual Maintenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3

1. ASHRAE 90.1 data for units larger than 150 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019).

Note:
For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.
ASHRAE 90.1 went into effect in October 2019.
Ranges represent the span of typical values for a given parameter.

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Commercial Screw Chillers (Air-Cooled Only)

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- Screw chillers are common in 150 to 500-ton capacities but are most cost effective for small (<300 tons) loads; screw chillers dominate the current market for small to mid-size chillers.
- Screw chillers can be used in either air-cooled or water-cooled applications. Screw chillers shown in the data are air-cooled. Air-cooled chillers are less efficient than the water-cooled models. Listed efficiencies include matched condensers and their associated energy use.
- ASHRAE 90.1-2019 stipulates minimum efficiencies for all air-cooled chillers together, including screw chillers, while water-cooled chillers are separated by positive displacement (e.g., screw) versus centrifugal models. Air-cooled chiller efficiencies are further split by size for more and less than 150 tons. ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly lower full-load efficiency in exchange for much higher part-load efficiency. For example, for a ≥ 150-ton unit:
  - Path A: ≥ 10.1 EER full-load and ≥ 14.0 IPLV EER
  - Path B: ≥ 9.7 EER full-load and ≥ 16.1 IPLV EER
- FEMP recommendations for air-cooled chillers (updated June 2020) are:
  - Path A (≥ 150 tons): ≥ 10.7 EER full-load and ≥ 14.0 IPLV EER
  - Path B (≥ 150 tons): ≥ 9.7 EER full-load and ≥ 16.4 IPLV EER
- The highest efficiency screw chillers incorporate some of the following:
  - Variable speed compressors and/or multiple compressors
  - Economizers
  - Improved heat-exchangers

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Commercial Scroll Chillers (Air-Cooled Only)

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DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019[1]	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	50	50	50	50	50	50	50	50	50	50	50
	140	140	140	140	140	140	140	140	140	140	140
Efficiency [full-load] (kW/ton)	1.23	1.16	1.19	1.15	1.07	1.11	1.06	1.07	1.02	1.02	0.97
Efficiency [IPLV] (kW/ton)	0.99	0.77	0.88	0.77	0.70	0.73	0.68	0.71	0.65	0.69	0.62
COP [full-load]	2.9	3.0	3.0	3.1	3.3	3.2	3.3	3.3	3.4	3.4	3.6
COP [IPLV]	3.7	4.6	4.0	4.6	5.0	4.8	5.2	5.0	5.4	5.1	5.7
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$/ton)	680	1,000	1,060	1,060	1,160	1,120	1,160	1,150	1,200	1,200	1,240
	560	820	530	530	630	590	630	620	670	670	710
Total Installed Cost (2022$/ton)	970	1,210	1,170	1,170	1,270	1,230	1,270	1,260	1,310	1,310	1,350
	850	970	860	860	960	920	960	950	1,000	1,000	1,040
Total Installed Cost (2022$/kBtu/h)	76	91	85	85	93	90	93	92	96	96	100
Annual Maintenance Cost (2022$/ton)	60	60	60	60	60	60	60	60	60	60	60
	40	40	40	40	40	40	40	40	40	40	40
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4

1. ASHRAE 90.1 data for units less than 150 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019).

Note:
For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.
ASHRAE 90.1 went into effect in October 2019.
Ranges represent the span of typical values for a given parameter.

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Commercial Scroll Chillers (Air-Cooled Only)

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- Scroll chillers range in size from ~20 tons to ~200 tons and can be used in either air-cooled or water-cooled applications. They are the most common type of chiller for small chiller plants. The scroll chillers shown in the data are air-cooled, which is most common. Air-cooled chillers are less efficient than the water-cooled models. Listed efficiencies include matched condensers and their associated energy use.
- ASHRAE 90.1-2019 stipulates minimum efficiencies for all air-cooled chillers together, including scroll chillers, while water-cooled chillers are separated by positive displacement (e.g., scroll) versus centrifugal models. Air-cooled chiller efficiencies are distinct for more and less than 150 tons. ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly lower full-load efficiency in exchange for much higher part-load efficiency. For example, for a 100-ton unit:
  - Path A: ≥ 10.1 EER full-load and ≥ 13.7 IPLV EER
  - Path B: ≥ 9.7 EER full-load and ≥ 15.8 IPLV EER
- FEMP recommendations for air-cooled chillers (updated June 2020) are:
  - Path A (< 150 tons): ≥ 10.7 EER full-load and ≥ 13.7 IPLV EER
  - Path B (< 150 tons): ≥ 9.7 EER full-load and ≥ 15.9 IPLV EER
- The highest efficiency scroll chillers incorporate some of the following:
  - Multiple compressors for staged capacity control
  - Improved heat-exchangers
  - Variable speed compressor (or other modulation controls)
- With the phase out of R-22, manufacturers have replaced many of their small reciprocating chiller products with equivalent scroll products, making them a primary choice for small tonnage applications.

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Commercial Gas-Fired Chillers (Water-Cooled, Direct-Fired Only)

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DATA	2012		2018		2022				2030		2040		2050	
	Installed Base: Absorption	Installed Base: Engine-Driven	Installed Base: Absorption	Installed Base: Engine-Driven	ASHRAE 90.1-2019 Absorption	CA Title 24 – Engine-Driven	Absorption	Engine-Driven	Absorption	Engine-Driven	Absorption	Engine-Driven	Absorption	Engine-Driven
Typical Capacity (tons)[1]	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	1,500	400	1,500	400	1,500	400	1,500	400	1,500	400	1,500	400	1,500	400
COP [full-load]	1.1	1.7	1.2	1.7	1.0	1.2	1.2	1.7	1.3	1.8	1.4	1.8	1.4	1.8
COP [IPLV]	NA	NA	1.6	2.6	1.0	2.0	1.6	2.6	1.6	2.6	1.6	2.6	1.6	2.6
Average Life (y)	23	25	23	25	23	25	23	25	23	25	23	25	23	25
Retail Equipment Cost (2022$/ton)	1,060	1,000	1,060	1,000	1,200	1,000	1,200	1,000	1,200	1,000	1,200	1,000	1,200	1,000
	880	880	880	880	870	880	870	880	870	880	870	880	870	880
Total Installed Cost (2022$/ton)	1,290	1,240	1,180	1,240	1,110	1,240	1,110	1,240	1,110	1,240	1,110	1,240	1,110	1,240
	1,000	1,000	1,000	1,000	850	1,000	850	1,000	850	1,000	850	1,000	850	1,000
Total Installed Cost (2022$/kBtu/h)	95	93	91	93	82	93	82	93	82	93	82	93	82	93
Annual Maintenance Cost (2022$/ton)	40	60	40	60	40	60	40	60	40	60	40	60	40	60
	20	40	20	40	20	40	20	40	20	40	20	40	20	40
Annual Maintenance Cost (2022$/kBtu/h)	3	4	3	4	3	4	3	4	3	4	3	4	3	4

1. Capacity is output.

Note:
This analysis assumes a water-cooled chiller; both gas-fired chiller types (absorption and engine-driven) are shown. COP values for double-effect absorption chillers are shown.
For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.
ASHRAE 90.1 went into effect in October 2019.
CA Title 24 went into effect in January 2020.
Ranges represent the span of typical values for a given parameter.

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Commercial Gas-Fired Chillers (Water-Cooled, Direct-Fired Only)

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- Gas-fired chillers are available as either air-cooled (~25-50 tons) or water-cooled (150+ tons). This analysis covers only water-cooled chillers of two varieties: absorption and engine-driven vapor compression (direct-fired only; indirect steam or hot water driven units are excluded).
- Direct gas firing provides high enough temperatures to operate double effect absorption chillers, which operate at a 50-60% higher COP than single effect systems. Triple effect chillers, though not commercially available, can boost cooling COP 30-50% beyond double effect chillers. Some companies have worked on prototype direct-fired triple effect absorption chillers, but prohibitively high cost of advanced high heat/corrosion-resistant materials required for triple effect absorption chillers suggests that this technology will not likely have an impact on the market in the near-term.
- Gas-fired engine-driven chillers pair conventional vapor compression systems (typically screw or centrifugal compressors) with natural gas powered-reciprocating engines. They exhibit higher peak cooling COP than absorbers, and engine modulation results in better part-load performance. Future efficiency improvements for engine-driven chillers are not anticipated. Engine-driven chillers allow the opportunity to recover waste heat for useful purposes.
- Maintenance costs for engine-driven chillers are higher than for other chillers because they include all the typical components of a vapor compression chiller in addition to an engine; the engine maintenance costs vary depending on the annual run hours of the unit.
- Limited sales data suggest that the U.S. market for gas-fired chillers is very limited and is mostly for replacement units, not for new installations. Recent increases in electric chiller efficiency have narrowed the operating cost differential with gas chillers. Asia has the majority of the global gas-fired chiller market.
- Gas-fired chiller installations are particularly valuable in locations where electric rates are high and gas prices are low (i.e., low spark spread), where digester or landfill gas sources are available, or where waste heat sources are available (e.g., an industrial process or microturbine CHP system) that could be used with a hybrid direct/indirect-fired absorption chiller to offset the use of natural gas.

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Commercial Rooftop Air Conditioners

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DATA	2012	2018	2022[4]				2023				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Output Capacity (kBtu/h)	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Part Load Efficiency (IEER)[1]	12.4	12.9	12.9	12.9	14.0	23.3	14.8	14.8	18.0	23.3	15.1	23.3	15.1	23.3	15.1	23.3
Efficiency (EER)[2]	10.6	11.5	11.5	11.5	12.2	12.8	12.2	12.2	12.7	12.8	12.2	12.8	12.2	12.8	12.2	12.8
Efficiency Conversion	3.6	3.8	3.8	3.8	4.1	6.8	4.3	4.3	5.3	6.8	4.4	6.8	4.4	6.8	4.4	6.8
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	7,760	8,280	8,280	8,280	9,090	12,210	9,490	9,490	10,340	12,210	9,590	12,210	9,590	12,210	9,590	12,210
Total Installed Cost (2022$)	10,350	11,870	11,870	11,870	13,020	17,600	13,560	13,560	14,970	17,600	13,720	17,600	13,720	17,600	13,720	17,600
Total Installed Cost (2022$/kBtu/h)	115	132	132	132	145	196	151	151	166	196	152	196	152	196	152	196
Annual Maintenance Cost (2022$)[3]	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4

1. Values shown are for air-cooled small commercial packaged air conditioners with either electric resistance heating or no heating within the same enclosure. DOE published a direct final rule for commercial packaged air conditioners and heat pumps in January 2016 with initial standards becoming effective in 2018 and additional standards becoming effective in 2023. As part of this rulemaking, DOE changed the regulated metric from EER to integrated energy efficiency ratio (IEER).
2. DOE investigated the relationship between IEER and EER. Because the relationship between IEER and EER is weak, this analysis estimates EER values based on the average of the values seen at a given IEER.
3. Examples of annual maintenance services include, check tensions, condition, and alignment of belts and adjust as necessary; lubricate shaft and motor bearings; replace air filters; clean coils, drain pan and piping, blowers, fan motors as required; check refrigerant pressure and compressor oil level; etc.
4. The 2022 typical efficiency is based on the average IEER from DOE's CCD. The 2022 high efficiency is based on the most-efficient model in DOE's CCD, but costs are estimated based on the most efficient unit analyzed in CUAC EERE 2016, which had an IEER of 21.5.

Note:
EER is the ratio of the cooling capacity (in Btu/h) to the power input (in watts) and provides a measure of the efficiency of equipment operating at full load (i.e., 100 percent cooling capacity) in high-ambient-temperature conditions (i.e., 95 °F). IEER is a single number part-load efficiency based on weighting of EER at various load capacities. Efficiency Conversion is the conversion of IEER from a [(Btu/h)/W] metric to a metric in the same units.
The previous standard went into effect in January 2018. The current standard went into effect in January 2023.
ENERGY STAR V. 3.1 went into effect in January 2018. ENERGY STAR V. 4.0 went into effect in January 2023.

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Commercial Rooftop Air Conditioners

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- Air-Cooled Commercial Packaged Air Conditioners

Cooling Capacity (kBtu/h)	Heating Type	Federal Standard Effective 1/1/2018 Min. IEER	Federal Standard Effective 1/1/2023 Min. IEER
Small (≥ 65 and < 135)	Electric resistance or none	12.9	14.8
	Any other type	12.7	14.6
Large (≥ 135 and < 240)	Electric resistance or none	12.4	14.2
	Any other type	12.2	14.0

- This analysis focused on small air-cooled commercial packaged rooftop air conditioners (90 kBtu/h or 7.5 tons), though there are also standards for many other types of commercial air conditioners.
- Amended standards in terms of IEER for all equipment classes took effect in January 2018. More stringent standards in terms of IEER for all equipment classes took effect in January 2023.

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Commercial Gas-Fired Engine-Drive Rooftop Air Conditioners

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DATA	2012[1]	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (tons)	18	11	11	11	11	11
Heating COP	1.4	1.4	1.4	1.4	1.4	1.4
Cooling COP	0.9	1.2	1.2	1.2	1.2	1.2
Average Life (y)	15	15	15	15	15	15
Retail Equipment Cost ($/ton)	3,350	2,820	3,710	3,710	3,710	3,710
Total Installed Cost ($/ton)	3,820	3,290	4,110	4,110	4,110	4,110
Total Installed Cost ($/kBtu/h)	318	274	343	343	343	343
Annual Maintenance Cost (2022$)	70	70	70	70	70	70
Annual Maintenance Cost (2022$/kBtu/h)	6	6	6	6	6	6

1. The 2012 typical capacity and cooling COP were estimated as a simple average between obsolete pre-2003 units and 2013 units, which first became available in 2010; this assumes that each vintage represents about half of the installed base.

Note:
Only one product was available in 2012; the market has grown slightly in years since. Typical capacity and COP for 2018 and later are averages of units available as of 2017.

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Commercial Gas-Fired Engine-Drive Rooftop Air Conditioners

- There are only a few gas-fired engine-driven rooftop units currently available in the U.S. market. The first unit was introduced in 2010. It is an 11-ton packaged heat pump with dual scroll compressors, variable refrigerant flow, and a variable speed supply fan. Engine coolant heat recovery improves the heating mode COP.
- There are currently no Federal requirements on gas-fired engine-driven rooftop air conditioners or heat pumps.
- Annual sales of the engine-driven rooftop heat pump are estimated at less than 5,000 units per year.

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Commercial Rooftop Heat Pumps

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DATA	2012	2018	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Part Load Efficiency (IEER)[1]	12.0	11.3	12.2	14.3	12.8	20.3	14.1	15.3	20.3	14.4	20.3	15.3	20.3	15.3	20.3
EER	10.2	11.2	11.3	11.5	11.8	13.0	12.0	11.8	13.0	11.7	13.1	11.7	13.1	11.7	13.1
COP (Heating)	3.3	3.3	3.3	3.4	3.4	3.7	3.4	3.5	3.7	3.4	3.7	3.5	3.7	3.5	3.7
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	7,490	7,490	9,000	10,250	9,380	12,920	10,160	10,600	12,920	10,290	12,920	10,600	12,920	10,600	12,920
Total Installed Cost (2022$)	9,350	9,350	12,900	14,940	13,530	18,860	14,810	15,520	18,860	15,000	18,860	15,510	18,860	15,510	18,860
Total Installed Cost (2022$/kBtu/h)	104	104	143	166	150	210	165	172	210	167	210	172	210	172	210
Annual Maintenance Cost (2022$)	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4

1. Values shown are for air-cooled small commercial packaged heat pumps with either electric resistance heating or no heating within the same enclosure. DOE published a direct final rule for commercial packaged air conditioners and heat pumps in January 2016 with initial standards becoming effective in 2018 and additional standards becoming effective in 2023. As part of this rulemaking, DOE changed the regulated metric from EER to IEER.

Note:
The previous standard went into effect in January 2018. The current standard went into effect in January 2023.
ENERGY STAR V. 3.1 went into effect in January 2018. ENERGY STAR V. 4.0 went into effect in January 2023.

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Commercial Rooftop Heat Pumps

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- Air-Cooled Commercial Packaged Heat Pumps

Cooling Capacity (kBtu/h)	Heating Type	Federal Standard Effective 1/1/2018 Min. IEER	Federal Standard Effective 1/1/2023 Min. IEER
Small (≥ 65 and < 135)	Electric resistance or none	12.2	14.1
	Any other type	12.0	13.9
Large (≥ 135 and < 240)	Electric resistance or none	11.6	13.5
	Any other type	11.4	13.3

- This analysis focused on small air-cooled commercial packaged rooftop heat pumps (90 kBtu/h or 7.5 tons), though there are also standards for many other types of commercial heat pumps.
- Amended standards in terms of IEER for all equipment classes took effect in 2018. More stringent standards in terms of IEER for all equipment classes took effect in 2023.

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Commercial Ground-Source Heat Pumps

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DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	48	48	48	48	48	48	48	48	48	48	48
COP (Heating)[1]	3.1	3.7	3.2	3.5	3.6	3.5	3.6	3.5	3.6	3.5	3.6
EER (Cooling)[2]	12.7	17.4	14.1	17.0	21.6	17.0	21.6	17.0	21.6	17.0	21.6
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8
	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	10,470	6,470	5,590	6,470	7,880	6,470	7,880	6,470	7,880	6,470	7,880
Total Installed Cost (2022$)	19,760	18,230	17,350	18,230	19,650	18,230	19,650	18,230	19,650	18,230	19,650
	44,820	26,520	25,580	26,520	27,880	26,520	27,880	26,520	27,880	26,520	27,880
Total Installed Cost (2022$/kBtu/h)	673	466	447	466	495	466	495	466	495	466	495
Annual Maintenance Cost (2022$)	180	180	180	180	180	180	180	180	180	180	180
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4

1. COP values listed are assessed at a "ground loop" test condition, which is representative of closed loop GSHP operating conditions. However, DOE sets standards at a "water loop" test condition. The AHRI directory lists COP ratings at both sets of test conditions and is used to convert between them where necessary.
2. EER values listed are assessed at a full-load "ground loop" test condition, which is representative of closed loop GSHP operating conditions. However, DOE sets standards at a full-load "water loop" test condition. The AHRI directory lists EER ratings at all sets of test conditions and is used to convert between them where necessary.

Note:
Residential and commercial GSHPs are very similar - the main difference in data presented is the different capacity (3-ton vs. 4-ton) and slightly higher installation costs for commercial GSHP. DOE does not distinguish between residential and commercial units in its regulations.

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Commercial Ground-Source Heat Pumps

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- The most common commercial ground-source heat pump systems are closed-loop in which water or anti-freeze solution is circulated through plastic pipes buried underground. Commercial water-to-air heat pumps (WAHPs) range in size from 1 ton or less to over 500 tons depending on whether a distributed or centralized architecture is used. Distributed systems are more prevalent.
- Most geothermal WAHPs are rated for capacity and efficiency based on the ISO 13256-1 standard. Heating and cooling efficiency measurements under this standard include input energy for fans and pumps on a proportional basis that only includes that power required to transport air and liquid through the heat pump. The reason for this method is to simplify comparisons between heat pumps and to allow equipment to be optimized for real world conditions without suffering rating penalties. Real world energy use will exceed ratings predictions as a result of higher fluid static pressure requirements.
- ISO 13256-1 cooling rating conditions require 77 °F entering water temperature and 80.6 °F entering air temperature. More typical peak design criteria would be 80-90 °F entering water temperature and 75 °F entering air temperature. As a result, ISO 13256-1 rated cooling efficiency would be higher than typical design peak operation.
- Some WAHPs include efficiency data for a part-load operating condition as allowed by ISO 13256-1 for multiple stage or variable speed compressors. No seasonal energy efficiency metric (analogous to SEER or IEER) currently applies to WAHPs. The annual performance of a geothermal WAHP system can vary more widely than for other system types due to the large influence of ground loop design and characteristics.
- The ENERGY STAR criteria for ground-source heat pumps apply only to residential applications.
- Installation cost is for a closed loop system and includes necessary accessories. The ground loop heat exchanger and distribution pumping systems represent a majority of the installation cost.
- Low end WAHPs utilize single stage compressors. Higher efficiency units incorporate multiple stage or variable speed compressor controls to improve efficiency as well as humidity and temperature control. Variable speed ECM fan motors also improve overall energy efficiency.

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Packaged Terminal Air Conditioners

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DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High[2]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)[1]	9	9	9	9	9	9	9	9	9	9	9
Efficiency (EER)	11.3	11.3	11.3	11.3	13.1	11.3	13.1	11.3	13.1	11.3	13.1
Efficiency	3.3	3.3	3.3	3.3	3.8	3.3	3.8	3.3	3.8	3.3	3.8
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8
Retail Equipment Cost (2022$)	1,460	1,460	1,460	1,460	1,560	1,460	1,560	1,460	1,560	1,460	1,560
Total Installed Cost (2022$)	1,740	1,740	1,740	1,740	1,840	1,740	1,840	1,740	1,840	1,740	1,840
Total Installed Cost (2022$/kBtu/h)	193	193	193	193	204	193	204	193	204	193	204
Annual Maintenance Cost (2022$)	70	70	70	70	70	70	70	70	70	70	70
Annual Maintenance Cost (2022$/kBtu/h)	8	8	8	8	8	8	8	8	8	8	8

1. Typical capacity is representative of units with the most shipments. It was also the representative cooling capacity for DOE's analysis in packaged terminal air conditioners (PTAC) and packaged terminal heat pumps (PTHP) EERE 2022 NOPD.
2. High values for 2022 and beyond are based on the max-tech level from PTAC & PTHP EERE 2022 NOPD.

Note:
The current standard went into effect in January 2017.

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Packaged Terminal Air Conditioners

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- PTAC are a self-contained, ductless air conditioning system used for commercial applications.
- Analysis was conducted for the standard equipment class at the representative cooling capacity of 9000 Btu/h.

Cooling Capacity (kBtu/h)	Equipment Size	Equipment Class	Federal Standard EER
PTAC	Standard	< 7000	11.9
		≥7,000 Btu/h and ≤15,000 Btu/h	14.0 – (0.3 x Cap)
		> 15,000 Btu/h	9.5

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Packaged Terminal Heat Pumps

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DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical[2]	High[3]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)[1]	9	9	9	9	9	9	9	9	9	9	9
Efficiency (EER)	11.3	11.3	11.3	11.3	13.1	11.5	13.1	11.5	13.1	11.5	13.1
Efficiency	3.3	3.3	3.3	3.3	3.8	3.4	3.8	3.4	3.8	3.4	3.8
COP (Heating)	3.2	3.2	3.2	3.2	3.6	3.3	3.6	3.3	3.6	3.3	3.6
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8
Retail Equipment Cost (2022$)	1,620	1,620	1,620	1,620	1,720	1,630	1,720	1,630	1,720	1,630	1,720
Total Installed Cost (2022$)	1,910	1,910	1,910	1,910	2,010	1,910	2,010	1,910	2,010	1,910	2,010
Total Installed Cost (2022$/kBtu/h)	212	212	212	212	223	212	223	212	223	212	223
Annual Maintenance Cost (2022$)	70	70	70	70	70	70	70	70	70	70	70
Annual Maintenance Cost (2022$/kBtu/h)	8	8	8	8	8	8	8	8	8	8	8

1. Typical capacity is representative of units with the most shipments. It was also the representative cooling capacity for DOE's analysis in PTAC & PTHP EERE 2022 NOPD.
2. Typical values for 2022 and beyond are based on the efficiency level that has the largest market share per PTAC & PTHP EERE 2022 NOPD.
3. High values for 2022 and beyond are based on the max-tech level from PTAC & PTHP EERE 2022 NOPD.

Note:
The current standard went into effect in October 2012.

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Packaged Terminal Heat Pumps

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- PTHP are self-contained heat pumps primarily used for commercial applications.
- Analysis was conducted for the standard equipment class at the representative cooling capacity of 9000 Btu/h.

Cooling Capacity (kBtu/h)	Equipment Size	Equipment Class	Federal Standard EER	Federal Standard COP
PTHP	Standard	< 7000	11.9	3.3
		≥7,000 Btu/h and ≤15,000 Btu/h	14.0 – (0.3 x Cap)	3.7 – (0.052 x Cap)
		> 15,000 Btu/h	9.5	2.9
PTHP	Non-Standard	< 7000	9.3	2.7
		≥7,000 Btu/h and ≤15,000 Btu/h	10.8 – (0.213 x Cap)	2.9 – (0.026 x Cap)
		> 15,000 Btu/h	7.6	2.5

Commercial Water Heating

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Commercial Gas-Fired Storage Water Heaters

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DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Typical Storage Capacity (gal)	100	100	100	100	100	100	100	100	100	100	100	100
Typical Input Capacity (kBtu/h)	199	199	199	199	199	199	199	199	199	199	199	199
Thermal Efficiency (%)[1]	81	82	80	82	94	99	95	99	95	99	95	99
Average Life (y)	13	10	10	10	10	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)	3,870	3,890	3,850	3,890	4,180	4,290	4,200	4,290	4,200	4,290	4,200	4,290
	5,170	5,200	5,140	5,200	5,530	5,650	5,550	5,650	5,550	5,650	5,550	5,650
Total Installed Cost (2022$)	5,170	5,190	5,140	5,190	6,630	6,730	6,640	6,730	6,640	6,730	6,640	6,730
	8,440	8,460	8,410	8,460	8,590	8,710	8,610	8,710	8,610	8,710	8,610	8,710
Total Installed Cost (2022$/kBtu/h)	42	42	43	42	41	39	40	39	40	39	40	39
Annual Maintenance Cost (2022$)[2]	320	320	320	320	330	330	330	330	330	330	330	330
Annual Maintenance Cost (2022$/kBtu/h)	2	2	2	2	2	2	2	2	2	2	2	2

1. Different levels of standby loss were not included in this analysis.
2. Maintenance consists of sediment and scale removal once or twice per year and replacement of miscellaneous components such as gaskets and sealants. Condensing units have an additional cost for replacement of condensate neutralizer media every two years.

Note:
The current standard went into effect in October 2015.
ENERGY STAR V. 2.0 went into effect in October 2018.
The range of retail and installed costs represent the range from replacement market to new construction market.

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Commercial Gas-Fired Storage Water Heaters

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- Input capacity > 155 kBtu/h and storage capacity ≤ 140 gal
- Federal standard:
  - Minimum thermal efficiency: 80%
  - Maximum standby loss (Btu/h) : Input Rate/800 + 110 × (Rated Volume)$^{1/2}$
- ENERGY STAR requirements:
  - Minimum thermal efficiency: 94%
  - Maximum standby loss (Btu/h): 0.84 × [(Input Rate/800) + 110 × (Rated Volume)$^{1/2}$]
- Baseline units are typically constructed similarly to residential units, though with higher input capacities (and often higher storage volumes).
- High-efficiency units include condensing heat exchangers (typically stainless or enameled steel) to extract additional heat by condensing water vapor in flue gases. Condensing units also include an inducer fan system or power burner. The heat exchanger is typically contained within the tank, but some designs consist of an external heating module attached to a storage tank. Condensing units are expected to be the majority market share by 2030.
- Maintenance consists of sediment and scale removal once or twice per year and replacement of miscellaneous components such as gaskets and sealants. Condensing units have an additional cost for replacement of condensate neutralizer media every two years.

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Commercial Gas-Fired Storage Water Heaters

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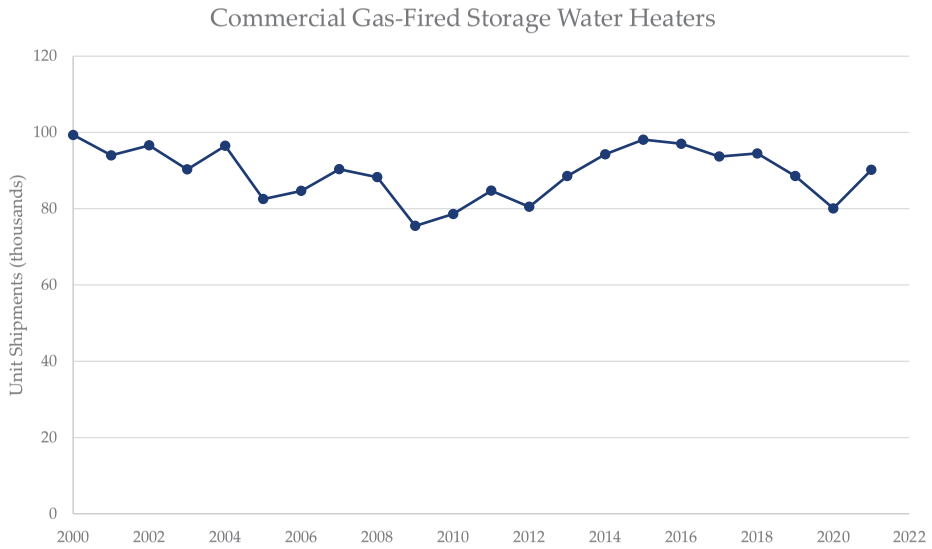
Annual shipments have fluctuated from 99,000 units in 2000 to 75,000 units in 2009, back to 99,000 units in 2015 and gradually decreasing since then until 2020.



Source: CWH EERE 2022 NOPR and AHRI

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Commercial Electric Resistance Storage Water Heaters

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DATA	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Storage Capacity (gal)	119	119	119	119	119	119	119
Typical Input Capacity (kW)[1]	18	18	18	18	18	18	18
Typical Input Capacity (kBtu/h)	60	60	60	60	60	60	60
Thermal Efficiency (%)	98	98	98	98	98	98	98
Average Life (y)	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)	3,180	3,180	3,180	3,180	3,180	3,180	3,180
	3,750	3,750	3,750	3,750	3,750	3,750	3,750
Total Installed Cost (2022$)	4,460	4,460	4,460	4,460	4,460	4,460	4,460
	4,690	4,690	4,690	4,690	4,690	4,690	4,690
Total Installed Cost (2022$/kBtu/h)	76	76	76	76	76	76	76
Annual Maintenance Cost (2022$)	50	50	50	50	50	50	50
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1

1. Different levels of standby loss were not included in this analysis.

Note:
No new standards rulemaking has been initiated for commercial electric resistance water heaters since CWH EERE 2016 NOPR. Accordingly, the results are the same as EIA Technology Forecast Updates (2018), updated to 2022$.
The range of retail equipment and installed costs represents the range from replacement market to new construction market.

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Commercial Electric Resistance Storage Water Heaters

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- Federal standard:
  - Maximum standby loss (%/h) : 0.30 + 27/Measured Storage Volume
  - Minimum thermal efficiency: no standard, but all units have an efficiency ≥ 98%
- Storage capacity: typically, 50 to 120 gallons, though smaller and larger units exist for specialized applications
- Commercial units are typically constructed similar to residential units, though with higher input capacities (and often higher storage volumes).
- There is very little variation in thermal efficiency on the market; variation in standby loss is typically due to tank design and insulation thickness.
- Maintenance consists of sediment and scale removal once or twice per year.

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Commercial Electric Resistance Storage Water Heaters

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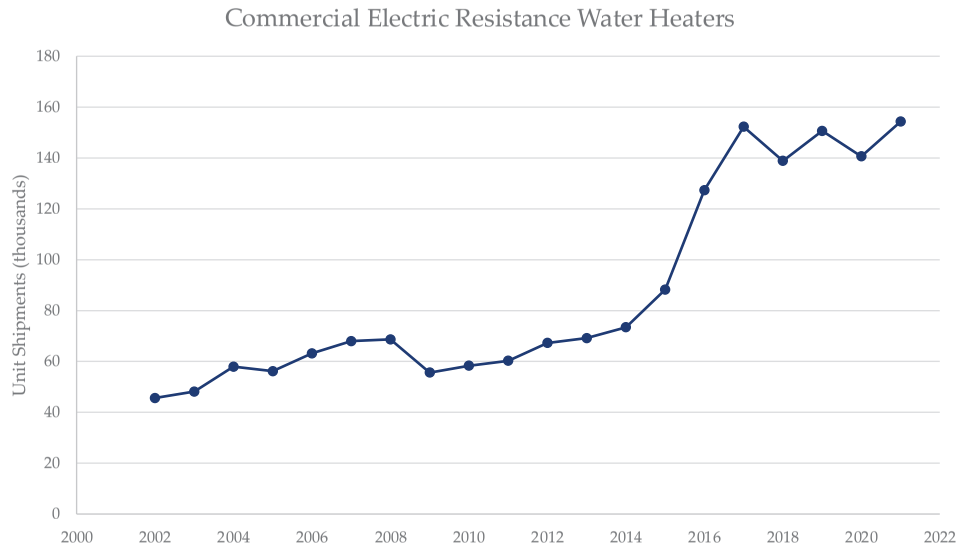
Annual shipments increased by almost 50% between 2002 and 2008. After a small dip in shipments in 2009, annual shipments have increased by about 173% between 2009 and 2017, stabilizing between 140-150 thousand shipments per year since then.



Source: AHRI

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Commercial Heat Pump Water Heaters

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DATA	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.0	Typical	Typical	Typical
Water Flow Rate (gal/min)[1]	34	34	34	34	34	34	34
Typical Output Capacity (kW)[1]	50	50	50	50	50	50	50
Typical Output Capacity (kBtu/h)	171	171	171	171	171	171	171
Coefficient of Performance (COP_h)	3.9	3.9	3.9	3.0	3.9	3.9	3.9
Average Life (y)	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	55,406	55,406	55,406	55,406	55,406	55,406	55,406
Total Installed Cost (2022$)[2]	59,940	59,940	59,940	59,940	59,940	59,940	59,940
Total Installed Cost (2022$/kBtu/h)	351	351	351	351	351	351	351
Annual Maintenance Cost (2022$)[2]	120	120	120	120	120	120	120
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1

1. Water flow rate scales with typical capacity. The storage tanks must be purchased and installed separately from the HP unit. The typical output and flow rate provided are near the median of the products available on the market currently.
2. Costs are same as EIA Technology Forecast Updates (2018), updated to 2022$. Updated representative costs for commercial heat pump water heaters are not available due to the extremely small market for these products.

Note:
ENERGY STAR V. 2.0 went into effect in October 2018.

Commercial Heat Pump Water Heaters

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- Typical commercial HPWHs (CHPWHs) are add-on units designed to be used with a storage tank(s); integrated CHPWHs have emerged on the market (i.e., heat pump module and storage tank combined in one unit) in recent years.
- CHPWHs serve only a small portion of the commercial water heating (CWH) market, with the ENERGY STAR database listing only two manufacturers, each with one basic model listed.
- CHPWHs can extract heat from either air or water for heating potable water ("air-source" or "water-source"). The capacity of air-source CHPWHs falls at lower ambient air temperatures.
- Air-source CHPWHs cool the surrounding air, which can be desirable when installed indoors in applications with a year-round cooling load (e.g., a commercial kitchen).
- Output capacities for CHPWHs range from 17 kW to over 70 kW for air-source units and over 600 kW for water-source units.
- Some commercial applications require water as hot as 180 °F, such as dishwashing; however, most CHPWHs cannot deliver hot water at temperatures higher than 150 °F.
- There are no current Federal standards for CHPWHs, but DOE prescribes a test procedure for determining COP_h for CHPWHs.
- The most recent ENERGY STAR V. 2.0 specification for CWH equipment went into effect in October 2018. It specifies a COP_h level of 3.0 for CHPWHs.

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Commercial Oil-Fired Storage Water Heaters

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DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Storage Capacity (gal)	70	85	85	85	85	85	85	85	85	85	85
Typical Input Capacity (kBtu/h)	300	300	300	300	300	300	300	300	300	300	300
Thermal Efficiency (%)[1]	79	81	80	81	82	81	82	81	82	81	82
Average Life (y)	13	13	13	13	13	13	13	13	13	13	13
Retail Equipment Cost (2022$)	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470
Total Installed Cost (2022$)	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120
Total Installed Cost (2022$/kBtu/h)	26	25	26	25	25	25	25	25	25	25	25
Annual Maintenance Cost (2022$)	200	200	200	200	200	200	200	210	210	210	210
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1	1	1	1	1

1. Different levels of standby loss were not included in this analysis.

Note:
The commercial oil-fired water heaters market is very small; currently, there are only 4 basic models in DOE's CCD. DOE's rulemaking analysis for oil-fired water heaters has not been updated since 2001. The retail, installed, and maintenance costs have been updated from EIA Technology Forecast Updates (2018) to 2022$.
The current standard went into effect in October 2015.

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Commercial Oil-Fired Storage Water Heaters

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- Input capacity > 155 kBtu/h and storage capacity ≤ 140 gal
- Federal standard:
  - Minimum thermal efficiency: 80%
  - Maximum standby loss (Btu/h) : Input Rate/800 + 110 × (Rated Volume)$^{1/2}$
- Condensing units do not exist, thus the highest thermal efficiency on the market is 82%.
- Commercial units are typically constructed similar to residential units, though with higher input capacities (and often higher storage volumes).
- Maintenance costs include sediment and scale removal once or twice per year.
- The market for commercial oil-fired storage water heaters is very small; shipments are approximately 3% of shipments for commercial gas-fired storage water heaters.

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Commercial Electric Booster Water Heaters

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DATA	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (gal)	6	6	6	6	6	6
	16	16	16	16	16	16
Typical Output Capacity (kBtu/h)	1,374	1,374	1,374	1,374	1,374	1,374
Thermal Efficiency (%)	98	98	98	98	98	98
Average Life (y)	3	3	3	3	3	3
	10	10	10	10	10	10
Retail Equipment Cost (2022$)[1]	1,530	1,530	1,920	1,920	1,920	1,920
	3,290	3,530	4,560	4,560	4,560	4,560
Total Installed Cost (2022$)[1]	1,730	1,730	2,120	2,120	2,120	2,120
	3,490	3,730	4,760	4,760	4,760	4,760
Total Installed Cost (2022$/kBtu/h)	2	2	3	3	3	3
Annual Maintenance Cost (2022$)[2]	-	-	-	-	-	-
Annual Maintenance Cost (2022$/kBtu/h)	-	-	-	-	-	-

1. The 2012 and 2018 installed base costs are the same as EIA Technology Forecast Updates (2018), updated to 2022$. Retail costs for 2022 and later are based on the range of costs for products on the market today. Installed costs assume a $200 installation price.
2. Maintenance costs are negligible.

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Commercial Gas-Fired Booster Water Heaters

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DATA	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Capacity (gal)	3	3	3	3	3	3	3
	5	5	5	5	5	5	5
Typical Output Capacity (kBtu/h)	500	500	500	500	500	500	500
Thermal Efficiency (%)[1]	80	80	80	80	80	80	80
Average Life (y)	5	5	5	5	5	5	5
	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)[2]	5,530	5,760	7,130	7,130	7,130	7,130	7,130
	8,000	9,060	11,120	11,120	11,120	11,120	11,120
Total Installed Cost (2022$)[2]	5,830	6,060	7,430	7,430	7,430	7,430	7,430
	8,300	9,360	11,420	11,420	11,420	11,420	11,420
Total Installed Cost (2022$/kBtu/h)	14	15	19	19	19	19	19
Annual Maintenance Cost (2022$)	160	160	160	160	160	160	160
Annual Maintenance Cost (2022$/kBtu/h)	0	0	0	0	0	0	0

1. While EIA Technology Forecast Updates (2018) included high values reflecting condensing models, models currently available in the market do not exceed 80% efficiency.
2. The 2012 and 2018 installed base costs are the same as EIA Technology Forecast Updates (2018), updated to 2022$. Retail costs for 2022 and later are based on the range of costs for products on the market today. Installed costs assume a $300 installation price.

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Commercial Booster Water Heaters

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- Booster water heaters are installed, often at the point of use, in series with the main service water heating system to boost service water temperatures. The main service water heating system may provide 110-140 °F water, and the booster water heater may increase that temperature to 180-195 °F. Typical commercial applications for booster water heaters include commercial dishwashers, laundromats, hospitals, and car washes.
- Commercial booster water heaters are regulated by DOE as either storage or instantaneous water heaters, depending on the ratio of input capacity to storage volume. Units with input capacity < 4,000 Btu/h per gallon of stored water are storage water heaters; all other units are instantaneous water heaters.
- DOE's regulations do not currently include standards for electric instantaneous water heaters, but standards are included for electric storage water heaters, gas-fired instantaneous water heaters, and gas-fired storage water heaters.
- Condensing gas-fired booster water heaters, those with an efficiency of 90% of more, were analyzed previously. There are no condensing units currently on the market. Condensing gas-fired booster water heaters can only operate if the incoming water temperature is below 130 °F so there is enough heat transfer to condense.
- Booster water heaters typically have short lifetimes because of high usage and extreme temperatures.
- Shipments are small due to the limited number of applications.

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Commercial Gas-Fired Instantaneous Water Heaters

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DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High[2]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	250	250	250	250	250	250	250	250	250	250	250	250
	399	399	399	399	399	399	399	399	399	399	399	399
Thermal Efficiency (%)	80	92	80	92	94	99	96	99	96	99	96	99
Average Life (y)	17	17	17	17	17	17	17	17	17	17	17	17
	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)[1]	1,630	1,840	1,630	1,840	1,880	7,990	1,930	7,990	1,930	7,990	1,930	7,990
	4,400	8,610	4,400	8,610	9,000	9,990	9,400	9,990	9,400	9,990	9,400	9,990
Total Installed Cost (2022$)[1]	2,430	3,980	2,430	3,980	4,010	13,000	4,070	13,000	4,070	13,000	4,070	13,000
	10,380	13,560	10,380	13,560	13,950	14,950	14,350	14,950	14,350	14,950	14,350	14,950
Total Installed Cost (2022$/kBtu/h)	25	29	25	29	29	44	30	44	30	44	30	44
Annual Maintenance Cost (2022$)[3]	90	100	90	100	100	820	100	820	100	820	100	820
	760	820	760	820	820	830	830	830	830	830	830	830
Annual Maintenance Cost (2022$/kBtu/h)	2	2	2	2	2	3	1	3	1	3	1	3

1. Commercial gas-fired instantaneous water heaters are categorized into two groups: tankless water heater and hot water supply boiler. Tankless units are similar in design to residential tankless units. The hot water supply boiler has a much higher input and is similar in design to boilers. The large variation of total input capacity and design causes a large range of costs. The range of retail, installed, and maintenance costs represent the differences in design, as well as the cost ranges arising from replacement versus new construction markets.
2. High efficiency was determined based on DOE's CCD. The most efficient tankless water heater has a thermal efficiency of 96%. The most efficient hot water supply boiler has a thermal efficiency of 99%.
3. Maintenance consists replacement of miscellaneous components such as gaskets and sealants. Condensing units have an additional cost for replacement of condensate neutralizer media every two years.

Note:
For the installed base, current standard, and typical costs, low values represent costs for tankless water heaters in the replacement market while high values represent costs for hot water supply boilers in the new construction market. The range of costs for the High values are estimated costs for hot water supply boilers in the replacement and new construction market.
ENERGY STAR V. 2.0 went into effect in October 2018.

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Commercial Gas-Fired Instantaneous Water Heaters

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- Storage Capacity < 10 gallons and ≥ 10 gallons
- Federal standard:
  - Minimum thermal efficiency: 80%
  - Maximum standby loss (Btu/h): Input Rate/800 + 110 x (Rated Volume)$^{1/2}$
- ENERGY STAR requirements:
  - Minimum thermal efficiency: 94%
- Wall-mounted ("tankless") units typically do not exceed ~400,000 Btu/h and are similar in design to residential tankless units. Floor-mounted units ("circulating" or "volume" water heaters) are similar in design to boilers and can have input capacities in the millions of Btu/h. Floor-mounted units are typically installed with a storage tank.
- Despite high available input capacities, some installations use multiple units staged together, which may have reliability and/or efficiency benefits.
- Similar to storage water heaters, higher efficiencies are achieved with condensing operation, which requires a condensing heat exchanger and inducer fan or power burner. Some units include both non-condensing and condensing heat exchangers, while others include a single condensing heat exchanger.
- When replacing a storage water heater with an instantaneous water heater, there may be significant additional costs to upsize the gas supply line and change the venting.

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Commercial Gas-Fired Instantaneous Water Heaters

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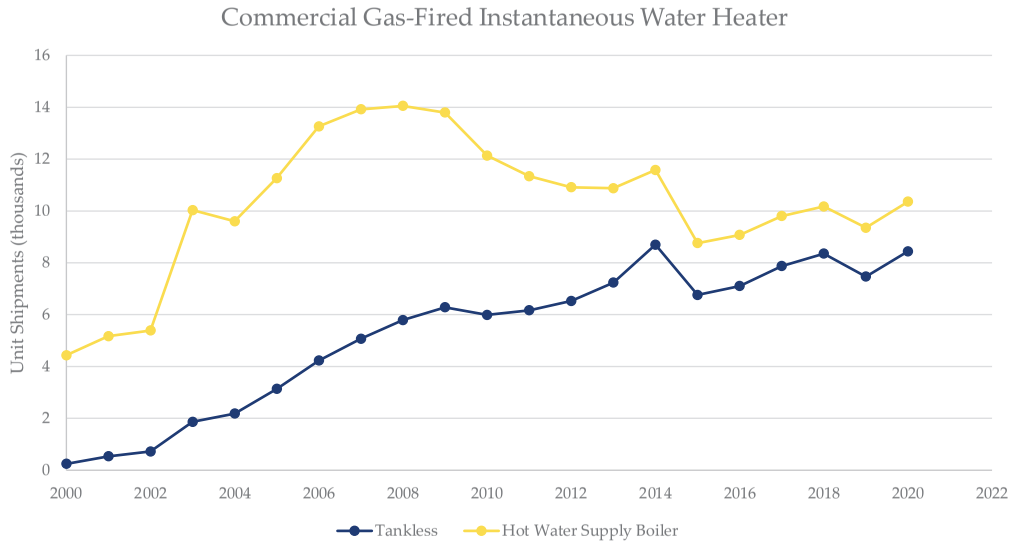
Annual shipments for gas-fired instantaneous tankless water heaters have gradually increased since 2000 while those for gas-fired instantaneous hot water supply boiler water heaters peaked in 2008 and have been decreasing since then, recently stabilizing around 10,000 annual shipments.



Source: CWH EERE 2022 NOPR

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Commercial Solar Water Heaters

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DATA	2012	2018	2022		2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	ENERGY STAR V. 5.0	Typical	Typical	Typical
Typical Capacity (sq. ft.)[1]	85	85	85	85	85	85	85	85
Typical Capacity (m^2)	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90
Typical Capacity (Input) (kBtu/h) – North	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05
Typical Capacity (Input) (kBtu/h) – South	6.74	6.74	6.74	6.74	6.74	6.74	6.74	6.74
Solar Uniform Energy Factor (SUEF)[2]	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Average Life (y)	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$)[3]	10,470	10,470	10,280	10,280	10,280	10,280	10,280	10,280
Total Installed Cost (2022$)[3]	14,180	14,180	12,640	12,640	12,640	12,640	12,640	12,640
Total Installed Cost (2022$/kBtu/h) – North	936	936	834	834	834	834	834	834
Total Installed Cost (2022$/kBtu/h) – South	702	702	626	626	626	626	626	626
Annual Maintenance Cost (2022$)[4]	100	100	100	100	100	100	100	100
Annual Maintenance Cost (2022$/kBtu/h) - North	7	7	7	7	7	7	7	7
Annual Maintenance Cost (2022$/kBtu/h) - South	5	5	5	5	5	5	5	5

1. Typical capacity refers to the solar collector panel area. It was determined using the SRCC database as the average value of the largest bin (in terms of capacity) with the greatest number of units.
2. In 2020, the efficiency metric for solar water heaters changed from SEF to SUEF. There is no equation or scaling factor readily available to translate SEF to SUEF. Accordingly, for the 2012 and 2018 installed base, SUEF was determined using the 2020 ENERGY STAR data set assuming the typical SEF/SUEF value was similar between 2012-2020. For 2022 and beyond, due to lack of SUEF data, it is assumed that a typical electric backup unit would meet the ENERGY STAR criteria. ENERGY STAR specifies a minimum SUEF of 3.0 for electric backup units and 1.8 for gas backup units.
3. Costs are for an indirect (active closed loop) system, including tank and backup heater. Smaller capacity/cost systems are typical for southern & western states (>two-third of the current market). Higher capacity/cost systems are required in colder/cloudier regions. The 2012 and 2018 installed base costs are updated from EIA Technology Forecast Updates (2018) to 2022$.
4. Annual maintenance is expected to be 0.5% to 1% of the total installation.

Note:
ENERGY STAR V. 4.0 went into effect in January 2022. ENERGY STAR V. 5.0 will go into effect in April 2023 but the ENERGY STAR criteria for solar water heaters will remain the same in ENERGY STAR V. 5.0.

Commercial Solar Water Heaters

- In 2020, a diverse group of stakeholders from the solar thermal industry developed the SUEF Specification for solar water heaters. The goal of this specification is to align with the UEF metric used by DOE for other water heating technologies.
- SUEF is also the metric used by the current ENERGY STAR Specification, and it replaced the SEF metric.
- EIA Technology Forecast Updates (2018) presented results using SEF and solar fraction (SF). SEF is currently not used in either the ENERGY STAR or SRCC databases; accordingly, this report presents results according to SUEF. SF is the portion of the total conventional hot water heating load (delivered energy and tank standby losses). SF varies from 0 to 1.0. Typical solar fraction values are 0.5–0.75.
- There is no equation or scaling factor readily available to translate SEF to SUEF. Accordingly, for the 2012 and 2018 installed base, SUEF was determined using the 2020 ENERGY STAR data set assuming the typical SEF/SUEF value was similar between 2012-2020. For 2022 and beyond, SUEF is the average SUEF for solar water heaters with a "high-usage" draw pattern from the current ENERGY STAR qualified product list.
- Commercial solar water heaters are typically custom designed for a specific installation.
- Commercial solar water heaters may include backup heating, from sources such as electric resistance or hydronic heat (supplied from a gas-fired boiler or geothermal heat pump).
- Storage volumes of tanks for commercial solar water heaters can span from 140 gallons to over 2,000 gallons.
- SRCC's OG-300 can be used to certify commercial systems, but most commercial systems are larger and unique; this certification program is mostly used for residential solar water heaters.
  - Many incentive programs require that solar collectors for commercial systems be certified to SRCC's certification program for collectors, OG-100.

Commercial Cooking Products

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Commercial Natural Gas Range with Griddle and Oven

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DATA	2012	2018	2022			2023	2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2[1]	High	ENERGY STAR V. 3.0[2]	Typical	High	Typical	High	Typical	High
Griddle - Cooking Energy Efficiency (%)	30	30	40	38	69	NA	40	69	40	69	40	69
Oven - Cooking Energy Efficiency (%)	35	35	35	46	69	49	35	69	35	69	35	69
Range - Cooking Energy Efficiency (%)	30	30	30	NA	40	NA	30	40	30	40	30	40
Combined Energy Efficiency (%)[3]	31	31	35	NA	58	NA	35	58	35	58	35	58
Griddle - Normalized Idle Energy Rate (Btu/h/ft^2)	3,000	3,000	3,000	2,650	1,724	NA	3,000	1,724	3,000	1,724	3,000	1,724
Oven - Idle Energy Rate (Btu/h)	18,000	18,000	18,000	12,000	3,516	9,500	18,000	3,516	18,000	3,516	18,000	3,516
Range - Idle Energy Rate (Btu/h)	3,600	3,600	3,600	NA	1,900	NA	3,600	1,900	3,600	1,900	3,600	1,900
Combined Idle Energy Rate (Btu/h)[3]	10,350	10,350	10,350	NA	4,178	NA	10,350	4,178	10,350	4,178	10,350	4,178
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
Total Installed Cost (2022$)	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940
Total Installed Cost (2022$/kBtu/h)	864	864	864	NA	2,140	NA	864	2,140	864	2,140	864	2,140
Annual Maintenance Cost (2022$)[5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. ENERGY STAR does not cover combination products that include griddles, ranges, and ovens in one single package. The ENERGY STAR levels provided here reflect specifications for individual products. Range tops are not covered by ENERGY STAR.
2. ENERGY STAR V. 3.0 updated the requirements for commercial ovens from V. 2.2, effective January 2023. Data shown is reflective of a standard full-size convection oven that holds 5 or more pans.
3. Combined energy efficiency and combined idle energy rate are calculated as a weighted average of each component using typical daily operating hours sourced from Food Service Technology Center (FSTC). Typical daily operating hours are assumed to be 12 hours for the griddle component, 8 hours for the oven component, and 12 hours for the range component.
4. Products in the commercial cooking market generally do not scale in price with relation to cooking efficiency. Distributors also do not provide this information.
5. Maintenance costs are negligible.

Note:
ENERGY STAR V. 2.2 went into effect in October 2015. ENERGY STAR V. 3.0 went into effect in January 2023.

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Commercial Electric Range with Griddle and Oven

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DATA	2012	2018	2022			2023	2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2[1]	High	ENERGY STAR V. 3.0[2]	Typical	High	Typical	High	Typical	High
Griddle - Cooking Energy Efficiency (%)	65	70	72	70	91	NA	72	91	72	91	72	91
Oven - Cooking Energy Efficiency (%)	65	65	65	71	86	76	65	86	65	86	65	86
Range - Cooking Energy Efficiency (%)	75	75	75	NA	87	NA	75	87	75	87	75	87
Combined Energy Efficiency (%)[3]	69	71	71	NA	88	NA	71	88	71	88	71	88
Griddle - Normalized Idle Energy Rate (kW/ft^2)	0.44	0.34	0.30	0.32	0.21	NA	0.30	0.21	0.30	0.21	0.30	0.21
Oven - Idle Energy Rate (kW)	1.5	1.5	1.5	1.6	0.6	1.4	1.5	0.6	1.5	0.6	1.5	0.6
Range - Idle Energy Rate (kW)[4]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Combined Idle Energy Rate (kW)[3]	1.7	1.4	1.3	1.4	0.8	NA	1.3	0.8	1.3	0.8	1.3	0.8
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[5]	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230
Total Installed Cost (2022$)	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410
Total Installed Cost (2022$/kBtu/h)	2,019	2,362	2,533	2,375	4,423	NA	2,533	4,423	2,533	4,423	2,533	4,423
Annual Maintenance Cost (2022$)[6]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. ENERGY STAR does not cover combination products that include griddles, ranges, and ovens in one single package. The ENERGY STAR levels provided here reflect specifications for individual products. Range tops are not covered by ENERGY STAR.
2. ENERGY STAR V. 3.0 updated the requirements for commercial ovens from V. 2.2, effective January 2023. Data shown is reflective of a standard full-size convection oven that holds 5 or more pans.
3. Combined energy efficiency and combined idle energy rate are calculated as a weighted average of each component using typical daily operating hours sourced from FSTC. Typical daily operating hours are assumed to be 12 hours for the griddle component, 8 hours for the oven component, and 12 hours for the range component.
4. No data on electric range top idle energy rates.
5. Products in the commercial cooking market generally do not scale in price with relation to cooking efficiency. Distributors also do not provide this information.
6. Maintenance costs are negligible.

Note:
ENERGY STAR V. 2.2 went into effect in October 2015. ENERGY STAR V. 3.0 goes into effect in January 2023.

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Commercial Ranges with Griddle and Oven

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- Combined product that typically includes 2-6 range tops, a 24 in. x 24 in. griddle surface, and one or two half- or full-size ovens.
- Combined product is not covered by ENERGY STAR. However, the individual product ENERGY STAR V. 2.2 specifications are provided below.

Product	ENERGY STAR V. 2.2 Requirements	Gas	Electric
Griddle	Cooking Energy Efficiency	≥ 38%	≥ 70%
	Normalized Idle Energy Rate	≤ 2,650 Btu/h per ft^2	≤ 0.320 kW per ft^2
Oven	Cooking Energy Efficiency	≥ 46%	≥ 71%
	Idle Energy Rate	≤ 12,000 Btu/h	Half size: ≤1.00 kW Full size: ≤1.60 kW

- ENERGY STAR does not provide certification for range tops.
- There are no Federal standards for commercial cooking products.
- Product pricing in this market do not scale with efficiency, but rather depend on a number of other factors such as brand name, aesthetics, and additional features.

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Commercial Ranges with Griddle and Oven

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- ENERGY STAR V. 3.0 requirements for commercial ovens went into effect in January 2023:

Product	ENERGY STAR Requirements	Gas	Electric
Oven	Cooking Energy Efficiency	≥ 49%	Half size: ≥ 71% Full size: ≥ 76%
	Idle Energy Rate	≤ 9,500 Btu/h	Half size: ≤1.00 kW Full size ≥ 5 Pans: ≤1.40 kW Full size ≤ 5 Pans: ≤1.00 kW

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Commercial Ranges with Griddle and Oven

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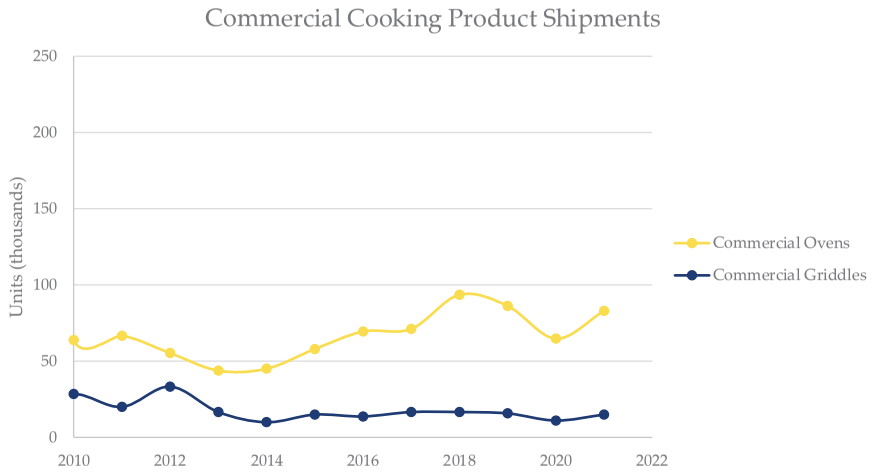
Commercial oven shipments have gradually increased since 2013, decreasing recently, in 2020. Commercial griddle shipments have remained steady since 2014.



Source: *ENERGY STAR (Unit Shipment Data)*

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Commercial Hot Food Holding Cabinets – Small

Final

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DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Interior Volume (ft^3)[1]	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Maximum Idle Energy Rate (W)[2]	312	312	312	312	168	168	312	168	312	168	312	168
Annual Energy Use (kWh/y)[3]	1,025	1,025	1,025	1,025	552	552	1,025	552	1,025	552	1,025	552
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	3,200	3,200	3,200	3,200	3,800	3,800	3,200	3,800	3,200	3,800	3,200	3,800
Total Installed Cost (2022$)[5]	3,200	3,200	3,200	3,200	3,800	3,800	3,200	3,800	3,200	3,800	3,200	3,800
Total Installed Cost (2022$/kBtu/h)	8,016	8,016	8,016	8,016	17,677	17,677	8,016	17,677	8,016	17,677	8,016	17,677
Annual Maintenance Cost (2022$) [5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. Interior volume is characterized by the product size classes reported by ENERGY STAR. The small size class covers units with interior volume less than 13 ft^3. Interior volume for the small size class was determined based on the units in the ENERGY STAR database, accessed February 2023.
2. Maximum idle energy rate is a function of interior volume. For the small size class, ENERGY STAR and high values were determined for a representative 7.8 ft^3 using the ENERGY STAR database, accessed February 2023. The typical value was assumed to be equivalent to the state standard for a representative 7.8 ft^3 unit.
3. Annual energy use is determined using the latest FEMP data from December 2021, which assumes that a typical 22.4 ft^3 commercial hot food holding cabinet uses an average of 9 hours per day and 365 days per year. The small size class is assumed to use the same number of annual usage hours as the medium size class.
4. Retail equipment costs were determined using distributor information for undercounter, half-size, and full-size hot food holding cabinets.
5. Additional installation costs and maintenance costs are negligible.

Note:
ENERGY STAR V. 2.0 went into effect in October 2011 and was revised in December 2022. Massachusetts, Nevada, and Rhode Island state standards have adopted the ENERGY STAR V. 2.0 criteria that went into effect in October 2011. The majority of state standards (California, Colorado, Connecticut, DC, Maryland, New Hampshire, Oregon, Rhode Island, Vermont, and Washington) implement the ENERGY STAR V. 1.0 specification that went into effect in August 2003, which is recorded in the table. ENERGY STAR V. 1.0 specifies a maximum idle energy rate of 40 W per cubic foot of interior volume.

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Commercial Hot Food Holding Cabinets – Medium

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DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Interior Volume (ft^3)[1]	21.4	21.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4
Maximum Idle Energy Rate (W)[2]	900	856	896	896	299	298	896	298	896	298	896	298
Annual Energy Use (kWh/y)[3]	2,957	2,812	2,943	2,943	982	979	2,943	979	2,943	979	2,943	979
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	2,940	4,530	4,600	4,600	5,000	5,000	4,600	5,000	4,600	5,000	4,600	5,000
Total Installed Cost (2022$)[5]	2,940	4,530	4,600	4,600	5,000	5,000	4,600	5,000	4,600	5,000	4,600	5,000
Total Installed Cost (2022$/kBtu/h)	2,553	4,136	4,012	4,012	13,078	13,113	4,012	13,113	4,012	13,113	4,012	13,113
Annual Maintenance Cost (2022$) [5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. Interior volume is characterized by the product size classes reported by ENERGY STAR. The medium size class covers units with interior volume between 13 ft^3 to 28 ft^3. For the medium size class, the interior volume increase from 21.4 ft^3 to 22.4 ft^3 in 2022 reflects the current representative product volume reported by FEMP, last updated December 2021.
2. Maximum idle energy rate is a function of interior volume. For the medium size class, the maximum idle energy rate for 2022 onward is reflective of a representative 22.4 ft^3 unit, using the latest FEMP data from December 2021.
3. Annual energy use is determined using the latest FEMP data from December 2021, which assumes that a typical 22.4 ft^3 commercial hot food holding cabinet uses an average of 9 hours per day and 365 days per year.
4. Retail equipment costs were determined using distributor information for undercounter, half-size, and full-size hot food holding cabinets.
5. Additional installation costs and maintenance costs are negligible.

Note:
ENERGY STAR V. 2.0 went into effect in October 2011 and was revised in December 2022. Massachusetts, Nevada, and Rhode Island state standards have adopted the ENERGY STAR V. 2.0 criteria that went into effect in October 2011. The majority of state standards (California, Colorado, Connecticut, DC, Maryland, New Hampshire, Oregon, Rhode Island, Vermont, and Washington) implement the ENERGY STAR V. 1.0 specification that went into effect in August 2003, which is recorded in the table. ENERGY STAR V. 1.0 specifies a maximum idle energy rate of 40 W per cubic foot of interior volume.

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Commercial Hot Food Holding Cabinets – Large

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DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Interior Volume (ft^3)[1]	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
Maximum Idle Energy Rate (W)[2]	1,333	1,333	1,760	1,333	400	310	1,333	310	1,333	310	1,333	310
Annual Energy Use (kWh/y)[3]	4,380	4,380	5,782	4,380	1,314	1,018	4,380	1,018	4,380	1,018	4,380	1,018
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	5,500	5,500	5,500	5,500	6,000	6,000	5,500	6,000	5,500	6,000	5,500	6,000
Total Installed Cost (2022$)[5]	5,500	5,500	5,500	5,500	6,000	6,000	5,500	6,000	5,500	6,000	5,500	6,000
Total Installed Cost (2022$/kBtu/h)	3,224	3,224	2,442	3,224	11,723	15,126	3,224	15,126	3,224	15,126	3,224	15,126
Annual Maintenance Cost (2022$) [5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. Interior volume is characterized by the product size classes reported by ENERGY STAR. The large size class covers units with interior volume greater than or equal to 28 ft^3. Interior volume for the large size class was determined based on the units in the ENERGY STAR database, accessed February 1, 2023.
2. Maximum idle energy rate is a function of interior volume. For the large size class, ENERGY STAR and high values were determined using the ENERGY STAR database, and the typical value uses the assumption that ENERGY STAR units are reported to be 70% more efficient than typical units.
3. Annual energy use is determined using the latest FEMP data from December 2021, which assumes that a typical 22.4 ft^3 commercial hot food holding cabinet uses an average of 9 hours per day and 365 days per year. The large size class is assumed to use the same number of annual usage hours as the medium size class.
4. Retail equipment costs were determined using distributor information for undercounter, half-size, and full-size hot food holding cabinets.
5. Additional installation costs and maintenance costs are negligible.

Note:
ENERGY STAR V. 2.0 went into effect in October 2011 and was revised in December 2022. Massachusetts, Nevada, and Rhode Island state standards have adopted the ENERGY STAR V. 2.0 criteria that went into effect in October 2011. The majority of state standards (California, Colorado, Connecticut, DC, Maryland, New Hampshire, Oregon, Rhode Island, Vermont, and Washington) implement the ENERGY STAR V. 1.0 specification that went into effect in August 2003, which is recorded in the table. ENERGY STAR V. 1.0 specifies a maximum idle energy rate of 40 W per cubic foot of interior volume.

Commercial Hot Food Holding Cabinets

- Hot food holding cabinets are used in commercial kitchens to keep food warm until it is served.
- While available in many shapes and sizes, interior volumes around 21.4 ft^3 were reported as typical in many settings in EIA Technology Forecast Updates (2018). FEMP currently lists 22.4 ft^3 as a representative unit size.
- Annual unit energy consumption can range from < 1,000 to > 30,000 kWh/y, depending on size, efficiency, and usage.
- Energy performance metric is "Idle Energy Consumption Rate" in Watts, measured using ASTM Standard F2140-11.
- There are no Federal standards for hot food holding cabinets, but seven States have identical standards.
  - The first State standard took effect in California in 2006; this standard is now considered the typical or "baseline" product. It is also equivalent to the ENERGY STAR V. 1.0 Specification that went into effect in August 2003.
  - ENERGY STAR V. 2.0 went into effect in October 2011.
- Maximum Idle Energy Consumption Rate for products $12 \le V < 28$:
  - State standards: $\le 40 \times V$ (baseline)
  - ENERGY STAR V. 2.0: $\le 2.0 \times V + 254$ (about 65% below baseline)

  where V is interior volume in ft^3.
- The most efficient products are about 80% below baseline.
- Energy savings achieved with insulation, automatic door closers, magnetic door gaskets, and Dutch doors (half-doors).

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Commercial Hot Food Holding Cabinets

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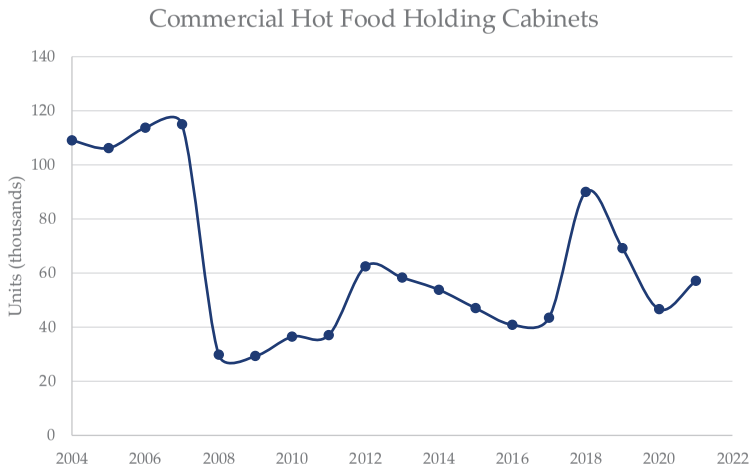
Commercial hot food holding cabinet shipments peaked in 2007 at 115,000 units, followed by a peak of 90,000 units in 2019.



Source: *ENERGY STAR (Unit Shipment Data)*

Appendix A
Data Sources

Guidehouse
1676 International Drive
McLean, VA 22102

And

Leidos
11951 Freedom Drive
Reston, VA 20190

Residential Space Heating and Cooling

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Residential Gas-Fired Furnaces (North)

Final

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (North) V. 4.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	Residential Furnaces EERE 2022 NOPR								
AFUE (%)	CFR			DOE CCD	ENERGY STAR V. 4.1	DOE CCD	Residential Furnaces EERE 2022 NOPR		
Electric Consumption (kWh/y)	Residential Furnaces EERE 2016		Residential Furnaces EERE 2022 NOPR						
Average Life (y)	Residential Furnaces EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Residential Furnaces EERE 2016		Residential Furnaces EERE 2022 NOPR						
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Gas-Fired Furnaces (Rest of Country)

Final

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (ROC) V. 4.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	Residential Furnaces EERE 2022 NOPR								
AFUE (%)	CFR			DOE CCD	ENERGY STAR V. 4.1	DOE CCD	Residential Furnaces EERE 2022 NOPR		
Electric Consumption (kWh/y)	Residential Furnaces EERE 2016		Residential Furnaces EERE 2022 NOPR						
Average Life (y)	Residential Furnaces EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Residential Furnaces EERE 2016		Residential Furnaces EERE 2022 NOPR						
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Oil-Fired Furnaces

Final

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	Residential Furnaces EERE 2011								
AFUE (%)	CFR			DOE CCD	ENERGY STAR V. 4.1	DOE CCD			
Electric Consumption (kWh/y)	Residential Furnaces EERE 2011								
Average Life (y)									
Retail Equipment Cost (2022$)									
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Gas-Fired Boilers

Final

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical / High		
Typical Input Capacity (kBtu/h)	Boilers EERE 2016	Boilers EERE 2022 Preliminary Analysis							
AFUE (%)		Boilers EERE 2022 Preliminary Analysis		DOE CCD	ENERGY STAR V. 3.0	Boilers EERE 2022 Preliminary Analysis			
Electric Consumption (kWh/y)		Boilers EERE 2022 Preliminary Analysis							
Average Life (y)									
Retail Equipment Cost (2022$)									
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Oil-Fired Boilers

Final

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical / High		
Typical Input Capacity (kBtu/h)	Boilers EERE 2016	Boilers EERE 2022 Preliminary Analysis							
AFUE (%)		Boilers EERE 2022 Preliminary Analysis		DOE CCD	ENERGY STAR V. 3.0	Boilers EERE 2022 Preliminary Analysis			
Electric Consumption (kWh/y)		Boilers EERE 2022 Preliminary Analysis							
Average Life (y)									
Retail Equipment Cost (2022$)									
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Electric Resistance Furnaces

Final

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical		
Typical Input Capacity (kBtu/h)	Distributors				Guidehouse		
AFUE (%)	DOE / ASHRAE						
Average Life (y)	Distributors						
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)	Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse						

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Residential Electric Resistance Unit Heaters

Final

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SOURCES	2015	2020	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical		
Typical Capacity (kBtu/h)	Distributors		Utilities/Distributors	Guidehouse		
Efficiency (%)	DOE		DOE			
Average Life (y)	Guidehouse		Guidehouse			
Retail Equipment Cost (2022$)			Distributors			
Total Installed Cost (2022$)			Home Remodeling Service			
Annual Maintenance Cost (2022$)			Guidehouse			

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Residential Central Air Conditioners – North (Not Hot-Dry or Hot-Humid)

Final

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SOURCES	2015	2020	2022				2023			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	CAC and HP EERE 2016									Guidehouse		
SEER	CAC and HP EERE 2016 / Guidehouse		CFR	DOE CCD	ENERGY STAR V. 5.0	CAC and HP EERE 2016	RESNET		CAC and HP EERE 2016			
SSER2	RESNET						CAC and HP EERE 2016	ENERGY STAR V. 6.1	RESNET			
Average Life (y)	CAC and HP EERE 2016											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)	CAC and HP EERE 2016 / Less (2021)											
Annual Maintenance Cost (2022$)	CAC and HP EERE 2016											

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Residential Central Air Conditioners – South (Hot-Dry and Hot-Humid)

Final

Return to Table of Contents

SOURCES	2015	2020	2022				2023			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	CAC and HP EERE 2016									Guidehouse		
SEER	CAC and HP EERE 2016 / Guidehouse		CFR	DOE CCD	ENERGY STAR V. 5.0	CAC and HP EERE 2016	RESNET		CAC and HP EERE 2016			
SSER2	RESNET						CAC and HP EERE 2016	ENERGY STAR V. 6.1	RESNET			
Average Life (y)	CAC and HP EERE 2016											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)	CAC and HP EERE 2016 / Less (2021)											
Annual Maintenance Cost (2022$)	CAC and HP EERE 2016											

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Residential Room Air Conditioners

Final

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.2	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Distributors		RAC EERE 2022 NOPR									
CEER (Btu/Wh)	Guidehouse		CFR	DOE CCD	ENERGY STAR V. 4.2	DOE CCD	RAC EERE 2022 NOPR	DOE CCD	RAC EERE 2022 NOPR	DOE CCD	RAC EERE 2022 NOPR	DOE CCD
Average Life (y)	RAC EERE 2011		RAC EERE 2022 NOPR									
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Portable Air Conditioners

Final

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SOURCES	2015	2020	2022		2025		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	New Standard	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	PAC EERE 2020/Guidehouse											
CEER												
Average Life (y)												
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Swamp Coolers

Final

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
CFM	Product Literature / Guidehouse				Guidehouse					
Power (Hp)										
Average Life (y)	TLC Plumbing / Guidehouse									
Retail Equipment Cost (2022$)	Product Literature / Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse									
Total Installed Cost (2022$)										
Annual Maintenance Cost (2022$)										

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Residential Air-Source Heat Pumps

Final

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SOURCES	2015	2020	2022				2023				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	ENERGY STAR Cold Climate Criteria	High	Typical/High		
Typical Capacity (kBtu/h)	CACs and HPs EERE 2016 Direct Final Rule												
SEER (Cooling)	CACs and HPs EERE 2016 Direct Final Rule/ Guidehouse		CFR	DOE CCD/ Guidehouse	ENERGY STAR V. 5.0	CACs and HPs EERE 2016 Direct Final Rule	CACs and HPs EERE 2016 Direct Final Rule/ Guidehouse	ENERGY STAR V. 6.1	ENERGY STAR V. 6.1	CACs and HPs EERE 2016 Direct Final Rule	CACs and HPs EERE 2016 Direct Final Rule/Guidehouse		
HSPF (Heating)													
Average Life (y)	CACs and HPs EERE 2016 Direct Final Rule										Guidehouse		
Retail Equipment Cost (2022$)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													

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Residential Ductless Mini-Split Air-Source Heat Pumps

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	AHRI/Guidehouse				Guidehouse					
SEER										
EER										
HSPF										
Average Life (y)	CACs and HPs EERE 2016 Direct Final Rule									
Retail Equipment Cost (2022$)	Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse									
Total Installed Cost (2022$)										
Annual Maintenance Cost (2022$)	CACs and HPs EERE 2016 Direct Final Rule									

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Residential Ground-Source Heat Pumps

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.2	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Water-Source Unitary Heat Pumps EERE 2015 Final Rule / DOE CCD		Guidehouse									
COP (Heating)	AHRI Database	AHRI Database / DOE CCD										
EER (Cooling)												
Average Life (y)	Guidehouse / Water-Source Unitary Heat Pumps EERE 2015 Final Rule											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Natural Gas Heat Pumps

Final

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SOURCES	2015	2020	2022	2030	2040	2050
	Installed Base		Typical			
Typical Capacity (kBtu/h)	Manufacturer		Guidehouse			
COP (Heating)	Product Literature					
COP (Cooling)						
Annual Electric Use (kWh/y)						
Average Life (y)	Guidehouse					
Retail Equipment Cost (2022$)	PERC					
Total Installed Cost (2022$)	Guidehouse					
Annual Maintenance Cost (2022$)						

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Residential Cordwood Stoves

Final

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Distributors / Product Literature				Guidehouse					
Efficiency (Non-Catalytic) (HHV)	Guidehouse / Literature	EPA Certified Wood Stove Database (Room Heaters)								
Efficiency (Catalytic) (HHV)										
Average Life (y)	Guidehouse									
Retail Equipment Cost (2022$)	Product Literature/Dealers									
Total Installed Cost (2022$)	Dealers	Dealers/Guidehouse								
Annual Maintenance Cost (2022$)	Dealers/Guidehouse									

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Residential Wood Pellet Stoves

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Distributors / Product Literature				Guidehouse					
Efficiency (HHV)	EPA Default/ Literature/ Guidehouse	EPA Certified Wood Stove Database (Room Heaters)								
Average Life (y)	Guidehouse									
Retail Equipment Cost (2022$)	Product Literature/ Dealers									
Total Installed Cost (2022$)	Dealers/Guidehouse									
Annual Maintenance Cost (2022$)										

Residential Water Heating

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Residential Gas-Fired Storage Water Heaters

Final

Return to Table of Contents

SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	Guidehouse	CWH EERE 2010 Final Rule /AHRI	CWH EERE 2022 Preliminary Analysis					Guidehouse					
Uniform Energy Factor		DOE CCD	CWH EERE 2022 Preliminary Analysis		ENERGY STAR	CWH EERE 2022 Preliminary Analysis	ENERGY STAR						
Average Life (y)	CWH EERE 2010 Final Rule		CWH EERE 2022 Preliminary Analysis										
Retail Equipment Cost (2022$)	Distributors	CWH EERE 2010 Final Rule											
Total Installed Cost (2022$)	EIA Technology Forecast Updates (2018)	CWH EERE 2010 Final Rule											
Annual Maintenance Cost (2022$)	CWH EERE 2010 Final Rule												

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Residential Oil-Fired Water Heaters

Final

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SOURCES	2015	2020	2022			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	Typical / High		
Typical Capacity (gal)	AHRI	CWH EERE 2010 Final Rule/AHRI	CWH EERE 2022 Preliminary Analysis			Guidehouse		
Uniform Energy Factor	Guidehouse	AHRI/DOE CCD						
Average Life (y)	CWH EERE 2010 Final Rule							
Retail Equipment Cost (2022$)								
Total Installed Cost (2022$)								
Annual Maintenance Cost (2022$)								

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Residential Electric Resistance Storage Water Heaters

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SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	AHRI	CWH EERE 2010 Final Rule/AHRI	CWH EERE 2022 Preliminary Analysis			Guidehouse					
Uniform Energy Factor	Guidehouse	AHRI/ DOE CCD									
Average Life (y)	CWH EERE 2010 Final Rule										
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Annual Maintenance Cost (2022$)											

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Residential Heat Pump Water Heaters

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SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	Guidehouse	AHRI	CWH EERE 2022 Preliminary Analysis			Guidehouse					
Uniform Energy Factor		DOE CCD	CWH EERE 2022 Preliminary Analysis	ENERGY STAR	CWH EERE 2022 Preliminary Analysis						
Average Life (y)	CWH EERE 2010 Final Rule		CWH EERE 2022 Preliminary Analysis								
Retail Equipment Cost (2022$)	CWH EERE 2010 Final Rule	Distributors									
Total Installed Cost (2022$)	CWH EERE 2010 Final Rule										
Annual Maintenance Cost (2022$)											

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Residential Solar Water Heaters

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	ENERGY STAR V. 4.0	Typical	Typical	Typical	Typical
Typical Capacity (sq. ft.)	SRCC / Guidehouse		ENERGY STAR		Guidehouse		
Solar Uniform Energy Factor (SUEF)			DOE				
Average Life (y)	DOE / Guidehouse						
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023				
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse		DOE				

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Residential Gas-Fired Instantaneous Water Heaters

Final

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SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	AHRI	CWH EERE 2010 Final Rule /AHRI	CWH EERE 2022 Preliminary Analysis					Guidehouse					
Uniform Energy Factor	Guidehouse	DOE CCD	CWH EERE 2022 Preliminary Analysis		ENERGY STAR	CWH EERE 2022 Preliminary Analysis	ENERGY STAR						
Average Life (y)	CWH EERE 2010 Final Rule		CWH EERE 2022 Preliminary Analysis										
Retail Equipment Cost (2022$)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													

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Residential Electric Instantaneous Water Heaters

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SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Guidehouse		CWH EERE 2022 Preliminary Analysis			Guidehouse					
Uniform Energy Factor			CWH EERE 2022 Preliminary Analysis/DOE CCD								
Average Life (y)			Gordian's RSMeans Data – Building Construction Costs 2023								
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Annual Maintenance Cost (2022$)			Guidehouse								

Residential Appliances

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Residential Refrigerator-Freezers (Top)

Final

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse	RF EERE 2021 Preliminary Analysis / Guidehouse					RF EERE 2021 Preliminary Analysis / Guidehouse					
Energy Consumption (kWh/y)		DOE CCD/ Guidehouse	CFR	DOE CCD	ENERGY STAR	DOE CCD						
Average Life (y)		RF EERE 2021 Preliminary Analysis / Guidehouse										
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Refrigerator-Freezers (Side)

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse	RF EERE 2021 Preliminary Analysis / Guidehouse					RF EERE 2021 Preliminary Analysis / Guidehouse					
Energy Consumption (kWh/y)		DOE CCD/ Guidehouse	CFR	DOE CCD	ENERGY STAR	DOE CCD						
Average Life (y)		RF EERE 2021 Preliminary Analysis / Guidehouse										
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Refrigerator-Freezers (Bottom)

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse	RF EERE 2021 Preliminary Analysis / Guidehouse					RF EERE 2021 Preliminary Analysis / Guidehouse					
Energy Consumption (kWh/y)		DOE CCD/ Guidehouse	CFR	DOE CCD	ENERGY STAR	DOE CCD						
Average Life (y)		RF EERE 2021 Preliminary Analysis / Guidehouse										
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Freezers (Chest)

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SOURCES	2015	2020	2022			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	Typical / High		
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse		RF EERE Preliminary Analysis 2021/DOE CCD			Guidehouse		
Energy Consumption (kWh/y)	Guidehouse		RF EERE Preliminary Analysis 2021	RF EERE Preliminary Analysis 2021/DOE CCD	DOE CCD			
Average Life (y)	RF EERE 2011 / Guidehouse		RF EERE Preliminary Analysis 2021		RF EERE Preliminary Analysis 2021			
Retail Equipment Cost (2022$)					RF EERE Preliminary Analysis 2021/DOE CCD			
Total Installed Cost (2022$)								
Annual Maintenance Cost (2022$)								

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Residential Freezers (Upright)

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SOURCES	2015	2022	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical / High		
Typical Capacity (ft^3)	RF EERE 2011/ Guidehouse		RF EERE Preliminary Analysis 2021/ DOE CCD				Guidehouse		
Energy Consumption (kWh/y)	Guidehouse		RF EERE Preliminary Analysis 2021	RF EERE Preliminary Analysis 2021/ DOE CCD	ENERGY STAR	DOE CCD			
Average Life (y)	RF EERE 2011 / Guidehouse		RF EERE Preliminary Analysis 2021			RF EERE Preliminary Analysis 2021			
Retail Equipment Cost (2022$)						RF EERE Preliminary Analysis 2021/ DOE CCD			
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Natural Gas Cooktops

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (kBtu/h)	Distributors / Product Literature				Guidehouse		
Integrated Annual Energy Consumption (kBtu/y)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						
Cooking Efficiency (%)	Guidehouse						
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2016 SNOPR / Consumer Cooking Products EERE 2020 NOPD						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Natural Gas Ovens

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (kBtu/h)	Consumer Cooking Products EERE 2016 SNOPR / Product Literature				Guidehouse		
Typical Cavity Volume (ft^3)	Consumer Cooking Products EERE 2016 SNOPR	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kBtu/y)							
Cooking Efficiency (%)	Guidehouse						
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD	Consumer Cooking Products EERE 2020 NOPD					
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2016 SNOPR						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Natural Gas Ranges

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity of Cooktop Component (kBtu/h)	Distributors / Product Literature				Guidehouse		
Typical Capacity of Oven Component (kBtu/h)	Consumer Cooking Products EERE 2016 SNOPR / Product Literature						
Typical Cavity Volume of Oven Component (ft^3)	Consumer Cooking Products EERE 2020 NOPD	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kBtu/y)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Guidehouse / Distributors / Gordian's RSMeans Data – Building Construction Costs 2023						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Cooktops

Final

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (W)	Consumer Cooking Products EERE 2016 SNOPR / Distributors				Guidehouse		
Integrated Annual Energy Consumption (kWh/y)	Consumer Cooking Products EERE 2020 NOPD						
Average Life (y)							
Retail Equipment Cost (2022$)							
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Ovens

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (W)	Consumer Cooking Products EERE 2016 SNOPR / Distributors				Guidehouse		
Typical Cavity Volume (ft^3)	Consumer Cooking Products EERE 2016 SNOPR	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kWh/y)							
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2020 NOPD						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Ranges

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity of Cooktop Component (W)	Consumer Cooking Products EERE 2016 SNOPR / Distributors				Guidehouse		
Typical Capacity of Oven Component (W)							
Typical Cavity Volume of Oven Component (ft^3)	Consumer Cooking Products EERE 2016 SNOPR	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kWh/y)							
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2020 NOPD						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Clothes Dryers

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SOURCES	2015	2020	2022				2030	2040	2040
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1	High	Typical / High		
Typical Capacity (ft^3)	DOE CCD					Guidehouse / DOE CCD / ENERGY STAR	Guidehouse		
CEF, D1 (lb/kWh)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse	DOE CCD	Consumer Clothes Dryers EERE 2022 NOPR	DOE CCD	ENERGY STAR V. 1.1	DOE CCD			
CEF, D2 (lb/kWh)						ENERGY STAR			
Average Life (y)	Consumer Clothes Dryers EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse								
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR								

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Residential Natural Gas Clothes Dryers

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1	High	Typical / High		
Typical Capacity (ft^3)	DOE CCD						Guidehouse		
CEF, D1 (lb/kWh)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse	DOE CCD	Consumer Clothes Dryers EERE 2022 NOPR	DOE CCD	ENERGY STAR V. 1.1	DOE CCD			
CEF2, D2 (lb/kWh)									
Average Life (y)	Consumer Clothes Dryers EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse								
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR								

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Residential Clothes Washers (Front)

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical / High		
Typical Capacity (ft^3)	Guidehouse	DOE CCD / Guidehouse	DOE CCD	DOE CCD	DOE CCD	DOE CCD	Guidehouse		
Integrated Modified Energy Factor (ft^3/kWh/cycle)	AHAM / Guidehouse		RCW EERE 2021 Preliminary Analysis		ENERGY STAR V. 8.1				
Integrated Water Factor (gal/cycle/ft^3)									
Average Life (y)	RCW EERE 2021 Preliminary Analysis								
Water Consumption (gal/cycle)	Guidehouse / RCW EERE 2021 Preliminary Analysis								
Hot Water Energy (kWh/cycle)									
Machine Energy (kWh/cycle)									
Dryer Energy (kWh/cycle)									
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)	RCW EERE 2021 Preliminary Analysis/ Distributors							
Total Installed Cost (2022$)		RCW EERE 2021 Preliminary Analysis/ Guidehouse							
Annual Maintenance Cost (2022$)	RCW EERE 2021 Preliminary Analysis / Guidehouse								

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Residential Clothes Washers (Top)

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical / High		
Typical Capacity (ft^3)	Guidehouse	Guidehouse	DOE CCD	DOE CCD	DOE CCD	DOE CCD	Guidehouse		
Integrated Modified Energy Factor (ft^3/kWh/cycle)	AHAM / Guidehouse	RCW EERE 2021 Preliminary Analysis			ENERGY STAR V. 8.1	DOE CCD			
Integrated Water Factor (gal/cycle/ft^3)									
Average Life (y)	RCW EERE 2021 Preliminary Analysis								
Water Consumption (gal/cycle)	RCW EERE 2021 Preliminary Analysis / Guidehouse								
Hot Water Energy (kWh/cycle)	Guidehouse	RCW EERE 2021 Preliminary Analysis / Guidehouse							
Machine Energy (kWh/cycle)									
Dryer Energy (kWh/cycle)									
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)								
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)	RCW EERE 2021 Preliminary Analysis / Guidehouse								

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Residential Dishwashers

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SOURCES	2015	2020	2022				2023	2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 6.0	High	ENERGY STAR V. 7.0	Typical / High		
Typical Annual Energy Use (kWh/y)	AHAM 2014 / DW EERE 2012 Final Rule	Guidehouse / DOE CCD / ENERGY STAR	CFR	Guidehouse / DOE CCD / ENERGY STAR	ENERGY STAR	DW EERE 2022 Preliminary Analysis	ENERGY STAR	Guidehouse		
Water Consumption (gal/cycle)										
Water Heating Energy Use (kWh/y)	AHAM 2014 / DW EERE 2012 Final Rule	DW EERE 2016 Direct Final Rule	DW EERE 2022 Preliminary Analysis							
Average Life (y)	DW EERE 2016 Direct Final Rule/Guidehouse									
Retail Equipment Cost (2022$)	DW EERE 2012 Final Rule	DW EERE 2016 Direct Final Rule								
Total Installed Cost (2022$)										

Commercial Space Heating and Cooling

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Commercial Gas-Fired Furnaces

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SOURCES	2012	2018	2022			2023		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	Typical		
Typical Input Capacity (kBtu/h)	AHRI	CWAF EERE 2015	DOE CCD				Guidehouse			
Thermal Efficiency (%)		DOE CCD	CFR	DOE CCD		CFR				
Typical Output Capacity (kBtu/h)	Guidehouse									
Average Life (y)	CWAF EERE 2015									
Retail Equipment Cost (2022$)										
Total Installed Cost (2022$)										
Total Installed Cost (2022$/kBtu/h)										
Annual Maintenance Cost (2022$)										
Annual Maintenance Cost (2022$/kBtu/h)										

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Commercial Oil-Fired Furnaces

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SOURCES	2012	2018	2022			2023		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	Typical/High		
Typical Input Capacity (kBtu/h)	AHRI	DOE CCD	DOE CCD					Guidehouse		
Thermal Efficiency (%)			10 CFR 431.77	DOE CCD		10 CFR 431.77				
Typical Output Capacity (kBtu/h)	Guidehouse									
Average Life (y)	CWAF EERE 2015									
Retail Equipment Cost (2022$)										
Total Installed Cost (2022$)										
Total Installed Cost (2022$/kBtu/h)										
Annual Maintenance Cost (2022$)										
Annual Maintenance Cost (2022$/kBtu/h)										

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Commercial Electric Resistance Heaters

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SOURCES	2012		2018		2022		2030		2040		2050	
	Small	Large	Small	Large	Small	Large	Small	Large	Small	Large	Small	Large
Typical Capacity (kBtu/h)	Distributors/Guidehouse						Guidehouse					
Efficiency (%)	Guidehouse/DOE											
Average Life (y)	Technology Cost and Performance File for Commercial Model for AEO2010											
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)				Gordian's RSMeans Data – Building Construction Costs 2023							
Total Installed Cost (2022$)												
Total Installed Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$)	Guidehouse											
Annual Maintenance Cost (2022$/kBtu/h)												

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Commercial Electric Boilers

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SOURCES	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical			
Typical Capacity (kW)	BSRIA		Guidehouse			
Efficiency (%)	EERE / Guidehouse					
Average Life (y)	ASHRAE 2007 HVAC Applications	ASHRAE 2015 HVAC Applications	ASHRAE 2019 HVAC Applications			
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse			
Total Installed Cost (2022$)			Gordian's RSMeans Data – Building Construction Costs 2023			
Total Installed Cost (2022$/kBtu/h)						
Annual Maintenance Cost (2022$)			EIA Technology Forecast Updates (2018)			
Annual Maintenance Cost (2022$/kBtu/h)						

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Commercial Gas-Fired Boilers

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Return to Table of Contents

SOURCES	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	Guidehouse	Comm. Packaged Boilers EERE 2020												
Thermal Efficiency (%)	ASHRAE Standard 90.1-2004 / Guidehouse	Comm. Packaged Boilers EERE 2020 / Guidehouse	DOE CCD			Comm. Packaged Boilers EERE 2020/Guidehouse								
Average Life (y)	Comm. Heating, AC, WH EERE 2009	Comm. Packaged Boilers EERE 2020												
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)													
Total Installed Cost (2022$)														
Total Installed Cost (2022$/kBtu/h)														
Annual Maintenance Cost (2022$)	Comm. Heating, AC, WH EERE 2009													
Annual Maintenance Cost (2022$/kBtu/h)														

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Commercial Oil-Fired Boilers

Final

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SOURCES	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	Guidehouse	Comm. Packaged Boilers EERE 2020												
Thermal Efficiency (%)	ASHRAE Standard 90.1-2004 / Guidehouse	Comm. Packaged Boilers EERE 2020 / Guidehouse	DOE CCD			Comm. Packaged Boilers EERE 2020/Guidehouse								
Average Life (y)	Comm. Heating, AC, WH EERE 2009	Comm. Packaged Boilers EERE 2020												
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)													
Total Installed Cost (2022$)														
Total Installed Cost (2022$/kBtu/h)														
Annual Maintenance Cost (2022$)	Comm. Heating, AC, WH EERE 2009													
Annual Maintenance Cost (2022$/kBtu/h)														

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Commercial Centrifugal Chillers (Water-Cooled)

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	IPCC/ARB/TEAP/Guidehouse					Guidehouse					
Efficiency (kW/ton)	ASHRAE 90.1-2010/FEMP/ eSource/ Product Literature	ASHRAE 90.1-2019/Product Lit									
COP											
Average Life (y)	2007 ASHRAE Applications Handbook	2015 ASHRAE Applications Handbook A37 Table 4									
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)	Gordian's RSMeans Data – Building Construction Costs 2023									
Total Installed Cost (2022$/ton)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power										
Annual Maitnenance Cost (2022$/kBtu/h)											

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Commercial Reciprocating Chillers (Air-Cooled Only)

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	BSRIA/DEER		Guidehouse			Guidehouse					
Efficiency (kW/ton)	ASHRAE 90.1-2010/DEER/ FEMP/Product Literature	ASHRAE 90.1-2016 (>150 TR)	ASHRAE 90.1-2019		Product Lit						
COP	ASHRAE 90.1-2010/DEER/ FEMP/Product Literature	ASHRAE 90.1-2016 (>150 TR)									
Average Life (y)	Manufacturers	2015 ASHRAE Applications Handbook A37 Table 4									
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023								
Total Installed Cost (2022$/ton)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power										
Annual Maintenance Cost (2022$/kBtu/h)											

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Commercial Screw Chillers (Air-Cooled Only)

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SOURCES	2012	2018	2022			2030	2040	2050
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical/High		
Typical Capacity (tons)	Guidehouse					Guidehouse		
Efficiency (kW/ton)	Guidehouse	ASHRAE 90.1-2016 (>150 TR)	ASHRAE 90.1-2019 (>150 TR)	ASHRAE 90.1-2019 (>150 TR)/Product Lit	Product Lit			
COP								
Average Life (y)	Manufacturers	FacilitiesNet						
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$/ton)								
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Scroll Chillers (Air-Cooled Only)

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SOURCE	2012	2018	2022			2030	2040	2050
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical / High		
Typical Capacity (tons)	Guidehouse/Manufacturers					Guidehouse		
Efficiency [full-load/IPLV] (kW/ton)	Guidehouse	Product Lit/ Guidehouse	ASHRAE 90.1-2019 (>150 TR)	Product Lit/ Guidehouse	Product Lit			
COP [full-load/IPLV]								
Average Life (y)	Manufacturers							
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$/ton)								
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Gas-Fired Chillers (Water-Cooled, Direct-Fired Only)

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SOURCES	2012		2018		2022				2030	2040	2050
	Installed Base: Absorption	Installed Base: Engine-Driven	Installed Base: Absorption	Installed Base: Engine-Driven	ASHRAE 90.1-2019 Absorption	CA Title 24 – Engine-Driven	Absorption	Engine-Driven	Absorption/Engine-Driven		
Typical Capacity (tons)	BSRIA/Distributors								Guidehouse		
COP [full-load]	Product Literature/ Guidehouse		Product Lit		ASHRAE 90.1-2019 Direct-fired Double Effect	CA Title 24 Gas Engine Standard	Product Lit				
COP [IPLV]											
Average Life (y)	2007 ASHRAE Applications Handbook/ Distributors		2015 ASHRAE Applications Handbook A37 Table 4								
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)				Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse						
Total Installed Cost (2022$/ton)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power										
Annual Maintenance Cost (2022$/kBtu/h)											

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Commercial Rooftop Air Conditioners

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SOURCES	2012	2018	2022				2023				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Output Capacity (kBtu/h)	AHRI / Guidehouse	CUAC EERE 2016									CUAC EERE 2016 / Guidehouse					
Part Load Efficiency (IEER)	CUAC EERE 2016				ENERGY STAR	CUAC EERE 2016			ENERGY STAR	CUAC EERE 2016						
Efficiency (EER)	CUAC EERE 2016 / Guidehouse															
Efficiency Conversion	Calculated															
Average Life (y)	CUAC EERE 2016															
Retail Equipment Cost (2022$)	Distributors / Guidehouse / DEER, 2008	CUAC EERE 2016														
Total Installed Cost (2022$)																
Total Installed Cost (2022$/kBtu/h)	Calculated															
Annual Maintenance Cost (2022$)	CUAC EERE 2016															
Annual Maintenance Cost (2022$/kBtu/h)	Calculated															

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Commercial Gas-Fired Engine-Drive Rooftop Air Conditioners

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SOURCES	2012	2018	2022	2030	2040	2050
	Installed Base		Typical			
Typical Capacity (tons)	EIA Technology Forecast Updates (2018)		Guidehouse			
Heating COP						
Cooling COP						
Average Life (y)						
Retail Equipment Cost ($/ton)			Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse			
Total Installed Cost ($/ton)						
Total Installed Cost ($/kBtu/h)						
Annual Maintenance Cost (2022$)						
Annual Maintenance Cost (2022$/kBtu/h)						

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Commercial Rooftop Heat Pumps

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SOURCES	2012	2018	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	EECUHP EERE 2016									CUHP EERE 2016 / Guidehouse					
Part Load Efficiency (IEER)	CUHP EERE 2016 / Guidehouse				ENERGY STAR		CUHP EERE 2016	ENERGY STAR	CUHP EERE 2016						
COP (Heating)															
Average Life (y)	EIA Technology Forecast Updates (2018)		CUHP EERE 2016												
Retail Equipment Cost (2022$)															
Total Installed Cost (2022$)															
Total Installed Cost (2022$/kBtu/h)															
Annual Maintenance Cost (2022$)															
Annual Maintenance Cost (2022$/kBtu/h)															

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Commercial Ground-Source Heat Pumps

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	U.S. DOE/EIA	Water-Source Unitary Heat Pumps EERE 2015 Final Rule				Guidehouse					
COP (Heating)	Guidehouse	AHRI Database									
EER (Cooling)											
Average Life (y)	Guidehouse / Water-Source Unitary Heat Pumps EERE 2015 Final Rule										
Retail Equipment Cost (2022$)	Distributors/Guidehouse	Water-Source Unitary Heat Pumps 2015 EERE Final Rule / Guidehouse									
Total Installed Cost (2022$)	U.S. DOD/IGSHPA/MA DOER/CEFIA/ ASHRAE										
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$)	Geothermal Heat Pump Consortium, Inc. (U.S. DOE Contract DE-FG07-95ID13347)										
Annual Maintenance Cost (2022$/kBtu/h)											

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Packaged Terminal Air Conditioners

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	PTAC & PTHP EERE 2022 NOPD					PTAC & PTHP EERE 2022 NOPD / Guidehouse					
Efficiency (EER)											
Efficiency											
Average Life (y)											
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$)											
Annual Maintenance Cost (2022$/kBtu/h)											

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Packaged Terminal Heat Pumps

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	PTAC & PTHP EERE 2022 NOPD					PTAC & PTHP EERE 2022 NOPD / Guidehouse					
Efficiency (EER)											
Efficiency											
COP (Heating)											
Average Life (y)											
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$)											
Annual Maintenance Cost (2022$/kBtu/h)											

Commercial Water Heating

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Commercial Gas-Fired Storage Water Heaters

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SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Typical Storage Capacity (gal)	EIA Technology Forecast Updates (2018)	CWH EERE 2022 NOPR										
Typical Input Capacity (kBtu/h)												
Thermal Efficiency (%)		DOE CCD / Guidehouse	CFR	DOE CCD/ Guidehouse	ENERGY STAR	DOE CCD	CWH EERE 2022 NOPR / Guidehouse					
Average Life (y)		CWH EERE 2022 NOPR										
Retail Equipment Cost (2022$)	CWH EERE 2022 NOPR											
Total Installed Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$)												
Annual Maintenance Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$/kBtu/h)												

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Commercial Electric Resistance Storage Water Heaters

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SOURCES	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical		
Typical Storage Capacity (gal)	Product Literature / Guidehouse	CWH EERE 2016 NOPR			Guidehouse		
Typical Input Capacity (kW)	Product Literature						
Typical Input Capacity (kBtu/h)							
Thermal Efficiency (%)	Guidehouse						
Average Life (y)	CWH EERE 2016 NOPR						
Retail Equipment Cost (2022$)	CWH EERE 2016 NOPR / Guidehouse	CWH EERE 2016 NOPR					
Total Installed Cost (2022$)							
Total Installed Cost (2022$/kBtu/h)							
Annual Maintenance Cost (2022$)							
Annual Maintenance Cost (2022$/kBtu/h)							

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Commercial Heat Pump Water Heaters

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SOURCES	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.0	Typical	Typical	Typical
Water Flow Rate (gal/min)	Distributors/Guidehouse		Guidehouse				
Typical Output Capacity (kW)							
Typical Output Capacity (kBtu/h)							
Coefficient of Performance (COP_h)							
Average Life (y)	EERE/Guidehouse						
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)						
Total Installed Cost (2022$)							
Total Installed Cost (2022$/kBtu/h)							
Annual Maintenance Cost (2022$)	Guidehouse						
Annual Maintenance Cost (2022$/kBtu/h)							

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Commercial Oil-Fired Storage Water Heaters

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SOURCES	2012	2018	2022			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	Typical/High		
Typical Storage Capacity (gal)	AHRI / Guidehouse	DOE CCD/Guidehouse				Guidehouse		
Typical Input Capacity (kBtu/h)								
Thermal Efficiency (%)	Guidehouse		CFR	DOE CCD				
Average Life (y)	Commercial Heating, Air Conditioning and Water Heating Equipment EERE 2001							
Retail Equipment Cost (2022$)	Distributors / Guidehouse							
Total Installed Cost (2022$)								
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)								
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Electric Booster Water Heaters

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SOURCES	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (gal)	Product Literature / Guidehouse					
Typical Output Capacity (kBtu/h)						
Thermal Efficiency (%)						
Average Life (y)						
Retail Equipment Cost (2022$)						
Total Installed Cost (2022$)						
Total Installed Cost (2022$/kBtu/h)						
Annual Maintenance Cost (2022$)						
Annual Maintenance Cost (2022$/kBtu/h)						

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Commercial Gas-Fired Booster Water Heaters

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SOURCES	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Capacity (gal)	Product Literature / Guidehouse						
Typical Output Capacity (kBtu/h)							
Thermal Efficiency (%)							
Average Life (y)							
Retail Equipment Cost (2022$)							
Total Installed Cost (2022$)							
Total Installed Cost (2022$/kBtu/h)							
Annual Maintenance Cost (2022$)							
Annual Maintenance Cost (2022$/kBtu/h)							

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Commercial Gas-Fired Instantaneous Water Heaters

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SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	DOE CCD						DOE CCD / Guidehouse					
Thermal Efficiency (%)	Guidehouse/DOE CCD		DOE CCD		ENERGY STAR	DOE CCD						
Average Life (y)	CWH EERE 2022 NOPR											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Total Installed Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$)												
Annual Maintenance Cost (2022$/kBtu/h)												

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Commercial Solar Water Heaters

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SOURCES	2012	2018	2022		2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	ENERGY STAR V. 5.0	Typical	Typical	Typical
Typical Capacity (sq. ft.)	SRCC / Guidehouse					Guidehouse		
Typical Capacity (m^2)								
Typical Capacity (Input) (kBtu/h) - North								
Typical Capacity (Input) (kBtu/h) - South								
Solar Uniform Energy Factor (SUEF)	ENERGY STAR / Guidehouse							
Average Life (y)	SRCC / Guidehouse							
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$)								
Total Installed Cost (2022$/kBtu/h) - North	Guidehouse							
Total Installed Cost (2022$/kBtu/h) - South								
Annual Maintenance Cost (2022$)	DOE / Guidehouse							
Annual Maintenance Cost (2022$/kBtu/h) - North								
Annual Maintenance Cost (2022$/kBtu/h) - South								

Commercial Cooking Products

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Commercial Natural Gas Range with Griddle and Oven

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SOURCES	2012	2018	2022			2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2	High	ENERGY STAR V. 3.0	Typical/High		
Griddle - Cooking Energy Efficiency (%)	Guidehouse	FSTC	ENERGY STAR / FSTC	ENERGY STAR	ENERGY STAR	NA	Guidehouse		
Oven - Cooking Energy Efficiency (%)						ENERGY STAR			
Range - Cooking Energy Efficiency (%)			FEMP / CEC	NA	FEMP / CEC	NA			
Combined Energy Efficiency (%)	Guidehouse / FSTC								
Griddle - Normalized Idle Energy Rate (Btu/h/ft^2)	Guidehouse	FSTC	ENERGY STAR / FSTC	ENERGY STAR	ENERGY STAR	NA			
Oven - Idle Energy Rate (Btu/h)	FEMP		ENERGY STAR			ENERGY STAR			
Range - Idle Energy Rate (Btu/h)	FSTC			NA	FSTC	NA			
Combined Idle Energy Rate (Btu/h)	Guidehouse / FSTC / Distributors								
Average Life (y)	FSTC								
Retail Equipment Cost (2022$)	Distributors								
Total Installed Cost (2022$)	FSTC / Guidehouse								
Total Installed Cost (2022$/kBtu/h)									
Annual Maintenance Cost (2022$)	FSTC								
Annual Maintenance Cost (2022$/kBtu/h)									

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Commercial Electric Range with Griddle and Oven

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SOURCES	2012	2018	2022			2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2	High	ENERGY STAR V. 3.0	Typical/High		
Griddle - Cooking Energy Efficiency (%)	Guidehouse	FSTC	FSTC / ENERGY STAR / Guidehouse	ENERGY STAR	ENERGY STAR	NA	Guidehouse		
Oven - Cooking Energy Efficiency (%)						ENERGY STAR			
Range - Cooking Energy Efficiency (%)				NA	CEC	NA			
Combined Energy Efficiency (%)	Guidehouse / FSTC								
Griddle - Normalized Idle Energy Rate (kW/ft^2)	Guidehouse	FSTC	FSTC / ENERGY STAR / Guidehouse	ENERGY STAR	ENERGY STAR	NA			
Oven - Idle Energy Rate (kW)						ENERGY STAR			
Range - Idle Energy Rate (kW)	NA								
Combined Idle Energy Rate (kW)	Guidehouse / FSTC / Distributors								
Average Life (y)	FSTC								
Retail Equipment Cost (2022$)	Distributors								
Total Installed Cost (2022$)	FSTC / Guidehouse								
Total Installed Cost (2022$/kBtu/h)									
Annual Maintenance Cost (2022$)	FSTC								
Annual Maintenance Cost (2022$/kBtu/h)									

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Commercial Hot Food Holding Cabinets – Small

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SOURCES	2012	2018	2022				2030	2040
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical/High	
Interior Volume (ft^3)	FEMP / ENERGY STAR						Guidehouse	
Maximum Idle Energy Rate (W)	CEE / Guidehouse	FEMP	ASAP	ASAP / ENERGY STAR	ENERGY STAR V. 2.0	FEMP / ENERGY STAR		
Annual Energy Use (kWh/y)	FEMP							
Average Life (y)								
Retail Equipment Cost (2022$)	Distributors / ENERGY STAR Savings Calculator / Guidehouse							
Total Installed Cost (2022$)	Guidehouse							
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)	FSTC							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Hot Food Holding Cabinets – Medium

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SOURCES	2012	2018	2022				2030	2040
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical/High	
Interior Volume (ft^3)	FEMP / ENERGY STAR						Guidehouse	
Maximum Idle Energy Rate (W)	CEE / Guidehouse	FEMP	ASAP	ASAP / ENERGY STAR	ENERGY STAR V. 2.0	FEMP / ENERGY STAR		
Annual Energy Use (kWh/y)	FEMP							
Average Life (y)								
Retail Equipment Cost (2022$)	Distributors / ENERGY STAR Savings Calculator / Guidehouse							
Total Installed Cost (2022$)	Guidehouse							
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)	FSTC							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Hot Food Holding Cabinets – Large

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SOURCES	2012	2018	2022				2030	2040
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical/High	
Interior Volume (ft^3)	FEMP / ENERGY STAR						Guidehouse	
Maximum Idle Energy Rate (W)	CEE / Guidehouse	FEMP	ASAP	ASAP / ENERGY STAR	ENERGY STAR V. 2.0	FEMP / ENERGY STAR		
Annual Energy Use (kWh/y)	FEMP							
Average Life (y)								
Retail Equipment Cost (2022$)	Distributors / ENERGY STAR Savings Calculator / Guidehouse							
Total Installed Cost (2022$)	Guidehouse							
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)	FSTC							
Annual Maintenance Cost (2022$/kBtu/h)								

Appendix B
References

Guidehouse
1676 International Drive
McLean, VA 22102

And

Leidos
11951 Freedom Drive
Reston, VA 20190

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APPENDIX B

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Final

EIA - Technology Forecast Updates – Residential and Commercial Building Technologies – Advanced Case

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Objective

The objective of this study is to develop baseline and projected performance/cost characteristics for residential and commercial end-use equipment.

- Installed base in 2012 and 2018 (for commercial products) or 2015 and 2020 (for residential products) and current market (2022)
  - Review literature, standards, installed base, contractor, and manufacturer information
  - Provide a relative comparison and characterization of the cost/efficiency of a generic product
- Forecast of technology improvements that are projected to be available through 2050
  - Review trends in standards, product enhancements, and Research and Development (R&D)
  - Project impact of product improvements and enhancement to technology

The performance/cost characterization of end-use equipment developed in this study will assist EIA in projecting national primary energy consumption.

Methodology

Input from industry stakeholders, including government, R&D organizations, and manufacturers, was used to project product enhancements concerning equipment performance and cost attributes.

- Technology forecasting involves many uncertainties.
- Technology developments impact performance and cost forecasts.
- Varied sources ensure a balanced view of technology progress and the probable timing of commercial availability.
- Only currently published efficiency standards and regulations are considered when predicting technology developments; unpublished future regulatory action is not predicted.
- All costs are shown in 2022 dollars (2022$).
- Ranges, when given, represent the span of typical values for a given parameter (e.g., installed cost for equipment meeting the federal standard) not the highest and lowest available on the market.

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The Advanced Case and Reference Case both assume current level of effort for standards. However, the Advanced Case assumes an increase in market incentive and federal R&D. The general approach for the Advanced Case is outlined below.

- The Advanced Case considers future changes to product groups such as:
  - Product or component changes that are fully developed but have not yet been commercialized
  - Expected incremental improvements in existing technologies due to increased R&D
  - Increased adoption of existing higher efficiency technology options due to increased market incentives
- The Advanced Case did *not* include future changes to product groups that are due to:
  - Prototype technology changes or products that are in preliminary research that may have performance improvements but have only been demonstrated in theoretical calculations

Definitions

The following tables represent the current and projected efficiencies for residential and commercial building equipment ranging from the installed base in 2012 and 2018 (for commercial products) or 2015 and 2020 (for residential products) to the highest efficiency equipment that is expected to be commercially available by 2050, assuming incremental adoption. Below are definitions for the terms used in characterizing the status of each technology.

- Installed Base: Efficiency values are for those units installed and "in use" in that year. Cost values are for the typical new unit sold in that year.
- Current Standard: The minimum efficiency (or maximum energy use) that is required (allowed) by current U.S. Department of Energy (DOE) standards, when applicable.
- ENERGY STAR: The minimum efficiency that is required (or maximum energy use allowed) to meet the ENERGY STAR criteria, when applicable. The performance data that are presented are representative of certified products that just meet current ENERGY STAR specifications.
- Typical: Efficiency and cost values are for the average, or "typical," product being sold in the particular timeframe. This may represent either the shipments-weighted average product performance or the most common product on the market.
- High: Efficiency and cost values are for the product with the highest efficiency available in the particular timeframe.

Market Transformation

The market for the reviewed products has changed since this analysis was previously conducted.[1] These changes are noted and reflected in the efficiency and cost characteristics.

- In some categories the typical new product purchased today is more efficient than the average product in the installed base in 2012 (commercial) or 2015 (residential):
  - Residential sector: boilers, central air conditioners, room air conditioners, gas-fired furnaces (North), gas-fired furnaces (Rest of Country), oil-fired furnaces, electric resistance furnaces, heat pump water heaters, gas-fired instantaneous water heaters, natural gas cooktops, natural gas ovens, refrigerator-freezers, freezers, clothes dryers, clothes washers, and dishwashers
  - Commercial sector: gas-fired furnaces, oil-fired boilers, commercial rooftop heat pumps, commercial ground-source heat pumps, gas-fired instantaneous water heater, natural gas and electric ranges, griddles, and ovens
- More stringent Federal standards have taken effect for the following products:
  - Gas-fired and oil-fired boilers in 2021
  - Rooftop air conditioners and rooftop heat pumps in 2018
- Federal standards are slated to take effect in the coming years for the following products:
  - Central air conditioners, residential air-source heat pumps, gas-fired furnaces, oil-fired furnaces, gas-fired boilers, oil-fired boilers, rooftop air conditioners, and rooftop heat pumps in 2023
  - Portable air conditioners in 2025
- ENERGY STAR continues to raise the bar with revised criteria for:
  - Central air conditioners, residential air-source heat pumps, rooftop air conditioners, rooftop heat pumps, residential water heaters, and dishwashers in 2023

Note: The previous analysis is available in the EIA Technology Forecast Updates (2018) report.

Residential Space Heating and Cooling

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Residential Gas-Fired Furnaces (North)

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Same as Reference Case

DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (North) V. 4.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)[1]	80	80	80	80	80	80	80	80	80	80	80	80
AFUE (%)	80	80	80	90	95	99	95	99	95	99	95	99
Electric Consumption (kWh/y)[2]	374	374	386	636	631	725	631	725	631	725	631	725
Average Life (y)[3]	17	17	17	17	17	17	17	17	17	17	17	17
	26	26	26	26	26	26	26	26	26	26	26	26
Retail Equipment Cost (2022$)	1,300	1,300	1,080	1,200	1,220	1,390	1,220	1,390	1,220	1,390	1,220	1,390
Total Installed Cost (2022$)	2,880	2,880	3,690	4,130	4,150	4,320	4,150	4,320	4,150	4,320	4,150	4,320
Annual Maintenance Cost (2022$)	60	60	120	130	130	130	130	130	130	130	130	130

1. Typical input capacity is represented in terms of thousand British thermal units (kBtu) per hour (i.e., kBtu/h).
2. Electric consumption, represented in terms of kilowatt hours per year (kWh/y), accounts for the electricity consumption of components such as the furnace fan, draft inducer, and the ignitor. In some high efficiency products, this component also includes auxiliary equipment, such as condensate pumps and heat tape.
3. In the Residential Furnaces EERE 2022 Notice of Proposed Rulemaking (NOPR) Technical Support Document (TSD), an average lifetime of 22.5 years is calculated for gas-fired furnaces (North). Lifetime range was calculated using the Weibull Distribution in the Residential Furnaces EERE 2022 NOPR.

Note:
Models on the market can be either weatherized or non-weatherized. The majority (74%) are non-weatherized, and the values in the table use only non-weatherized data.
Electric consumption and cost values for 2022 and beyond are for a national sample and use the Residential Furnaces EERE 2022 NOPR Life-Cycle-Cost (LCC) spreadsheet.
Electric consumption and costs for the 2030, 2040, and 2050 high values are estimated based on the maximum-efficiency level analyzed in Residential Furnaces EERE 2022 NOPR, which is 98% annual fuel utilization efficiency (AFUE).
The current standard went into effect in November 2015.
ENERGY STAR V. 4.1 went into effect in February 2013.
The range for average life represents the span of typical values.

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Residential Gas-Fired Furnaces (Rest of Country)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (ROC) V. 4.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	80	80	80	80	80	80	80	80	80	80	80	80
AFUE (%)	80	80	80	90	90	99	95	99	95	99	95	99
Electric Consumption (kWh/y)[1]	279	279	386	636	636	725	631	725	631	725	631	725
Average Life (y)[2]	16	16	16	16	16	16	16	16	16	16	16	16
	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	1,260	1,260	1,080	1,200	1,200	1,390	1,220	1,390	1,220	1,390	1,220	1,390
Total Installed Cost (2022$)	2,380	2,380	3,690	4,130	4,130	4,320	4,150	4,320	4,150	4,320	4,150	4,320
Annual Maintenance Cost (2022$)	40	40	120	130	130	130	130	130	130	130	130	130

1. Electric consumption accounts for the electricity consumption of components such as the furnace fan, draft inducer, and the ignitor. In some high efficiency products, this component also includes auxiliary equipment, such as condensate pumps and heat tape.
2. In the Residential Furnaces EERE 2022 NOPR, an average lifetime of 21.5 years is calculated for gas-fired furnaces (Rest of Country). Lifetime range was calculated using the Weibull Distribution in the Residential Furnaces EERE 2022 NOPR.

Note:
Models on the market can be either weatherized or non-weatherized. The majority (74%) are non-weatherized, and the values in the table use only non-weatherized data.
Electric consumption and cost values for 2022 and beyond are for a national sample and use the Residential Furnaces EERE 2022 NOPR LCC spreadsheet.
Electric consumption and costs for the 2030, 2040, and 2050 high values are estimated based on the maximum-efficiency level analyzed in Residential Furnaces EERE 2022 NOPR, which is 98% AFUE.
The current standard went into effect in November 2015.
ENERGY STAR V. 4.1 went into effect in February 2013.
The range for average life represents the span of typical values.

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- Current Federal standards for non-weatherized gas furnaces:
  - AFUE ≥ 80%
- ENERGY STAR V. 4.1 criteria for gas furnaces:
  - South: AFUE ≥ 90%
  - North: AFUE ≥ 95%
  - Furnaces must be equipped with electronically commutated fan motor and have less than or equal to 2.0% air leakage
- Most efficient unit currently available: 99.0% AFUE. The current market is nearly evenly split between non-condensing units (AFUE≤82%) and condensing units (AFUE≥90%).
- The maximum AFUE for non-condensing gas furnaces is 82%; above this level, the potential for exhaust gas condensation increases. This condensate is corrosive and requires cost restrictive corrosion resistant venting.
- High-efficiency condensing furnaces typically have high-grade stainless steel (AL 29-4C) heat exchangers.
- Many condensing furnaces are available as direct vent and sealed combustion systems, which do not use room air for combustion, but instead draw combustion air directly from outdoors.
- Depending on the location of the home, piping materials in use, and other considerations, condensing furnaces may need an acid neutralizer and/or lift pump for the condensate.
- Furnaces may contain permanent split capacitor (PSC) fan motors or electronically commutated motors (ECMs). The type of motor affects the electrical consumption of the furnace as well as the seasonal energy efficiency ratio (SEER) / energy efficiency ratio (EER) of the associated air conditioner.
  - The 2016 Energy Conservation Standards for Residential Furnace Fans Final Rule requires that all furnaces use ECM fans.
  - Most non-weatherized gas furnaces employ ECMs and can fully modulate rather than cycling on and off. Because they modulate, there is an increase in total fan-on time.

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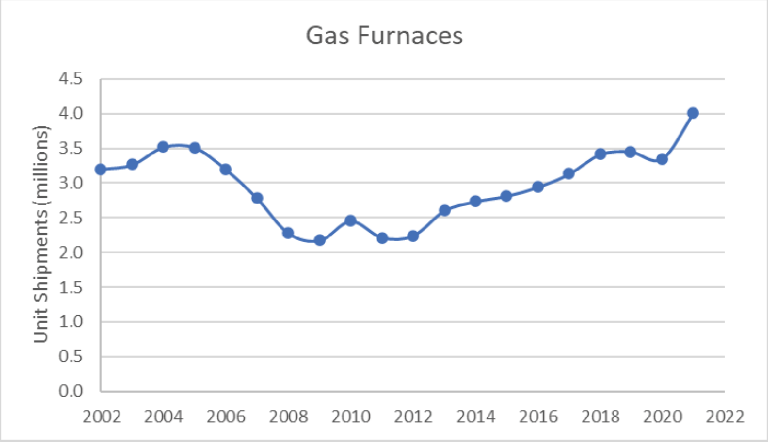
Annual shipments reached 3.5 million units in 2005 and then declined each year until 2009, leveling off at about 2.25 million units. Since 2012, shipments have increased steadily and reached a peak of 4.0 million units in 2021.



Source: *Air-Conditioning, Heating, and Refrigeration Institute (AHRI)*

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Residential Oil-Fired Furnaces

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Same as Reference Case

DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	105	105	105	105	105	105	105	105	105	105	105	105
AFUE (%)	83	83	83	85	85	97	85	97	85	97	85	97
Electric Consumption (kWh/y)[1]	477	477	477	466	466	410	466	410	466	410	466	410
Average Life (y)[2]	20	20	20	20	20	20	20	20	20	20	20	20
	33	33	33	33	33	33	33	33	33	33	33	33
Retail Equipment Cost (2022$)	2,620	2,620	2,620	2,650	2,650	3,170	2,650	3,170	2,650	3,170	2,650	3,170
	3,450	3,450	3,450	3,490	3,490	4,090	3,490	4,090	3,490	4,090	3,490	4,090
Total Installed Cost (2022$)	3,250	3,250	3,250	3,480	3,480	5,140	3,480	5,140	3,480	5,140	3,480	5,140
	6,520	6,520	6,520	6,820	6,820	10,110	6,820	10,110	6,820	10,110	6,820	10,110
Annual Maintenance Cost (2022$)	80	80	80	80	80	240	80	240	80	240	80	240

1. Electric consumption accounts for the electricity consumption of components such as the furnace fan, draft inducer, and the ignitor. In some high efficiency products, this component also includes auxiliary equipment, such as condensate pumps and heat tape.
2. Lifetime range was calculated using the Weibull Distribution in Residential Furnaces EERE 2011.

Note:
The current standard went into effect in May 2013.
ENERGY STAR V. 4.1 went into effect in February 2013.
Ranges represent the span of typical values for a given parameter.

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Residential Oil-Fired Furnaces

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- Current Federal standards:
  - AFUE ≥ 83%
  - ≤ 11 watts of electrical power when in standby and off modes (non-weatherized models only)
- ENERGY STAR V. 4.1 criteria: AFUE ≥ 85%
- Since the latent heat content of oil is lower than that for either propane or natural gas, oil-fired appliances can typically operate at a higher AFUE rating than comparable gas-fired appliances before condensation issues arise.
- Most efficient unit currently available: 96.7% AFUE – condensing units with tiny market share (<1%), due to market acceptance issues.
- Condensate from condensing oil furnaces is typically even more corrosive than that of gas-fired systems due to the higher sulfur content in fuel oil. Hence, condensing oil furnaces also likely require the use of an acid neutralizer.
- Oil-fired furnaces, like gas-fired furnaces, achieve condensing conditions through the use of a secondary heat exchanger. Typically, these secondary heat exchangers use a high-grade stainless steel (AL 29-4C).
- Sooting is an issue for all oil-fired appliances, but secondary heat exchangers, with their narrow passages, are even more prone to be plugged by soot. Because of this, condensing oil furnaces typically require frequent cleaning and maintenance.

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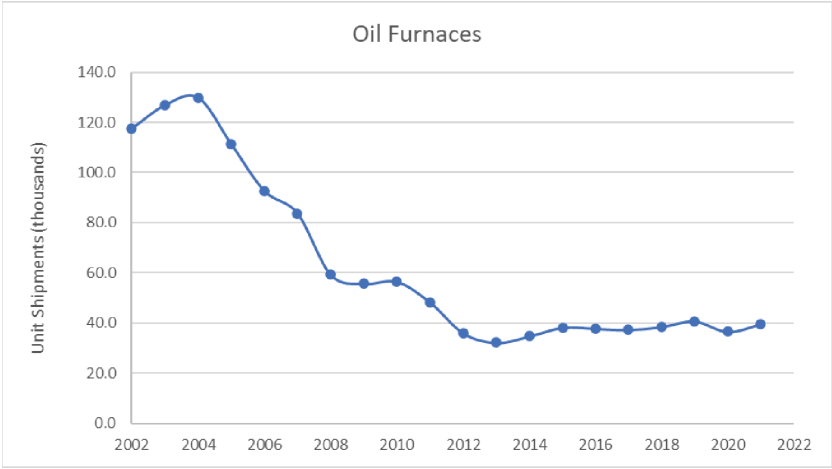
Annual shipments declined rapidly after 2004, likely due, at least in part, to an increase in fuel oil prices, which more than tripled from 2002 to 2008. Since 2012 shipments have largely leveled off.



Source: *AHRI*

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Residential Gas-Fired Boilers

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DATA	2015	2020[1]	2022				2030[2]		2040[2]		2050[2]	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	100	100	100	100	100	100	100	100	100	100	100	100
AFUE (%)	82	95	84	95	90	96	95	96	95	96	95	96
Electric Consumption (kWh/y)[3]	197	506	282	506	527	502	506	502	506	502	506	502
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20	20
	30	30	30	30	30	30	30	30	30	30	30	30
Retail Equipment Cost (2022$)	2,540	2,890	1,820	2,890	2,440	3,670	2,890	3,670	2,890	3,670	2,890	3,670
Total Installed Cost (2022$)	7,760	5,940	8,700	5,940	6,700	6,710	5,940	6,710	5,940	6,710	5,940	6,710
Annual Maintenance Cost (2022$)[4]	110	160	150	160	160	160	160	160	160	160	160	160

1. The 2020 AFUE is estimated based on EERE 2022 preliminary analysis, which estimates that gas-fired boilers with the highest market share in 2020 have an AFUE of 95%.
2. The 2030, 2040, 2050 projections are estimated based on the EERE 2022 preliminary analysis, which notes that majority of the market is expected to be condensing, if new standards are not implemented. The EERE 2022 preliminary analysis estimates a minimum efficiency of 95% AFUE for condensing units.
3. Electric Consumption accounts for the electricity consumption of auxiliary electrical components including circulating pump, the boiler pump (condensing boilers only), the draft inducer (if present), and the ignitor. It also accounts for the electricity consumption of auxiliary equipment such as a condensate pump and heat tape, which are sometimes installed with higher efficiency boilers. Additionally, it accounts for the additional cooling load due to heat loss from the boiler and water heater as a result of water heating during the cooling season.
4. Maintenance cost is the routine annual cost to the consumer of general maintenance for product operation. Maintenance cost is higher for condensing boilers for the inspection of condensate system and replacement of condensate neutralizer filter.

Note:
The current standard went into effect in January 2021.
ENERGY STAR V. 3.0 went into effect in December 2013.
Water boilers considered. Steam boilers also exist but make up a small percentage of the market.
The range for average life represents the span of typical values.

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- Federal standard for gas-fired hot-water boilers (more common than steam):
  - AFUE ≥ 84%
  - Standard went into effect on January 21, 2021
- ENERGY STAR criteria: AFUE ≥ 90%
- Most efficient gas-fired boiler available: 96.4% AFUE
- Gas-fired boilers have lost market share to furnaces and heat pumps over the past 30 years.
- U.S. gas hot water boiler sales are split approximately 60/40 between condensing and non-condensing.[1] Condensing boilers typically have heat exchangers made of stainless steel, and non-condensing boilers typically have heat exchangers made of cast iron.
- Typically, condensing boilers are low-mass in construction with modulating burners, variable-speed inducer fan systems or sealed powered direct-vent combustion, multiple sensor technologies, and electronic ignition and control.
- Due to incentives and market pressure, the U.S. boiler industry has been shifting towards also providing condensing boilers. Most of these boilers are private-labeled products sourced from Europe, where the hydronic market is much bigger and condensing appliances are much more common and/or required by law.
- Most value-added components for condensing boilers are sourced abroad, even when the condensing boiler is assembled in North America (e.g., heat exchanger, gas valve, burner, sensors, and/or controls).

Source: EERE 2022 Preliminary Analysis TSD, Chapter 3

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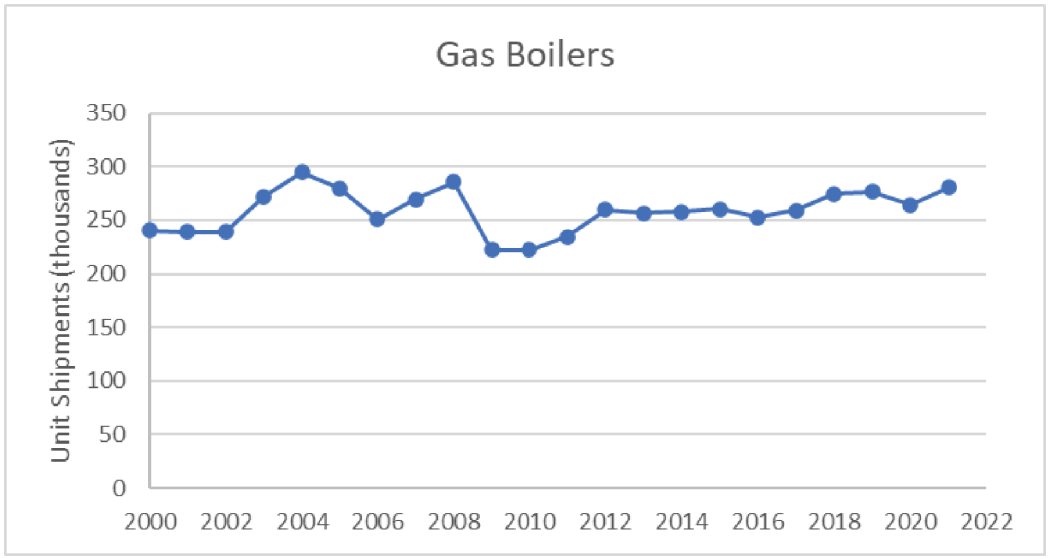
Annual shipments had a significant decrease following the 2009 financial crisis and a steady recovery in the years since.



Source: *Boilers EERE 2022 Preliminary Analysis*

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Residential Oil-Fired Boilers

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Typical AFUE and costs increase to ENERGY STAR levels. High AFUE and costs increase to condensing units.

DATA	2015	2020[1]	2022				2030[2]		2040[2]		2050[2]	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	140	140	140	140	140	140	140	140	140	140	140	140
AFUE (%)	84	86	86	86	87	88	87	95	87	95	87	95
Electric Consumption (kWh/y)[3]	230	310	310	310	307	305	307	265	307	265	307	265
Average Life (y)[4]	18	18	18	18	18	18	18	18	18	18	18	18
	28	28	28	28	28	28	28	28	28	28	28	28
Retail Equipment Cost (2022$)	4,850	3,590	3,590	3,590	3,680	3,770	3,680	6,890	3,680	6,890	3,680	6,890
Total Installed Cost (2022$)	9,800	5,510	5,510	5,510	5,600	5,690	5,600	11,910	5,600	11,910	5,600	11,910
Annual Maintenance Cost (2022$)[4]	160	170	170	170	170	170	170	170	170	170	170	170

1. The 2020 AFUE is estimated based on EERE 2022 preliminary analysis, which estimates that oil-fired boilers with the highest market share in 2020 have an AFUE of 86%.
2. The 2030, 2040, 2050 projections are estimated based on the EERE 2022 preliminary analysis, which notes that majority of the market is expected to be at 86% AFUE, if new standards are not implemented.
3. Electric Consumption accounts for the electricity consumption of auxiliary electrical components including circulating pump, the ignitor, condensate pump, and heat tape, which are sometimes installed with higher efficiency boilers. Additionally, it accounts for the additional cooling load due to heat loss from the boiler and water heater as a result of water heating during the cooling season.
4. Maintenance cost is the routine annual cost to the consumer of general maintenance for product operation.

Note:
The current standard went into effect in January 2021.
ENERGY STAR V. 3.0 went into effect in December 2013.
Water boilers considered. Steam boilers also exist but make up a small percentage of the market.
The range for average life represents the span of typical values.

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Residential Oil-Fired Boilers

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- Federal standard for oil-fired hot-water boilers (more common than steam):
  - AFUE ≥ 86%
  - Standard went into effect on January 21, 2021
- ENERGY STAR criteria: AFUE ≥ 87%
- Most efficient oil-fired boiler available: 88% AFUE
- Since the latent heat content of oil is lower than that for either propane or natural gas, oil-fired appliances can typically operate at a higher AFUE rating than comparable gas-fired appliances before condensation issues arise.
- Oil boilers have heat exchangers made of cast iron or steel.
- No condensing oil-fired boilers currently exist in the U.S. market. The high sulfur content in fuel-oil causes heat exchanger fouling if the flue gases from an oil-fired boiler were to condense. As a result, condensing oil-fired boilers would require more frequent maintenance and repair, if installed.
- Advanced Case: Increased incentives move typical efficiency products to ENERGY STAR levels by 2030. The current typical efficiency product is at 86% AFUE, while ENERGY STAR is at 87%, with only a small difference in costs. It is expected that with more market incentives, manufacturers will produce more products that can be ENERGY STAR certified at the 87% level.
- Advanced Case: High efficiencies expected to be at 95% AFUE for condensing oil-fired boilers. These models are already seen in Europe and would be expected to re-enter the U.S. market as well.

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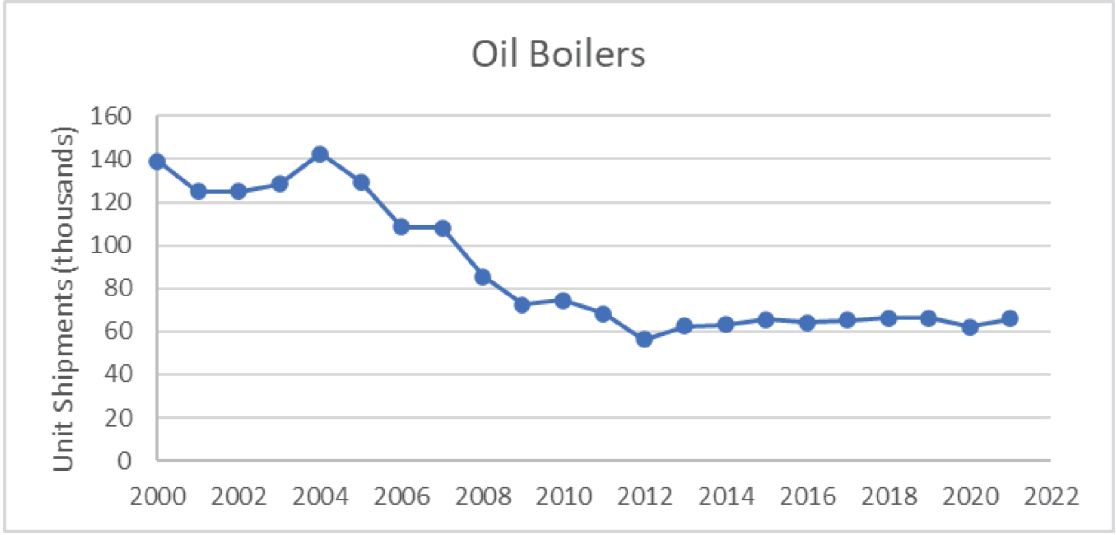
Annual shipments declined rapidly after 2004, likely due, at least in part, to an increase in fuel oil prices, which more than tripled from 2002 to 2008. Since 2012 shipments have largely leveled off.



Source: *Boilers EERE 2022 Preliminary Analysis*

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Residential Electric Resistance Furnaces

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Same as Reference Case

DATA	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Input Capacity (kBtu/h)	68	68	68	68	68	68	68
AFUE (%)	98	98	100	100	100	100	100
Average Life (y)	15	15	15	15	15	15	15
	30	30	30	30	30	30	30
Retail Equipment Cost (2022$)[1]	760	760	950	950	950	950	950
Total Installed Cost (2022$)[1]	1,290	1,290	1,480	1,480	1,480	1,480	1,480
Annual Maintenance Cost (2022$)[1]	50	50	50	50	50	50	50

1. Costs for a 100% AFUE unit are assumed to be equal to the costs of a 98% AFUE unit.

Note:
The current standard went into effect in January 1992.
The range for average life represents the span of typical values.

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Residential Electric Resistance Furnaces

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- Federal standards for electric furnaces:
  - AFUE ≥ 78%
  - Standby and off mode power consumption ≤ 10 watts
- According to preliminary Residential Energy Consumption Survey (RECS) data released May 2022, electric central warm-air furnaces are the main source of space heating in approximately 17.5 million U.S. homes or about 14%.
- Electric furnaces range in capacity from 10 to 25 kW (34 to 85 kBtu/h), with 20 kW (68 kBtu/h) being the typical for units on the market.
- Electric resistance furnaces are considered near 100% efficient because there is no flue heat loss, and any jacket losses are contained within the home.
  - ASHRAE Standard 103, the test method for furnaces incorporated by reference into the federal test procedure, specifies that for electric furnaces AFUE = 100 – 1.7 x jacket losses. Jacket losses can be determined either through testing or assumed to be 1%. Thus, the minimum AFUE of electric furnaces is 98.3%.

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Residential Electric Resistance Unit Heaters

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Same as Reference Case

DATA	2015	2020	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (kBtu/h)	3.5	3.5	5.1	5.1	5.1	5.1
Efficiency (%)	100	100	100	100	100	100
Average Life (y)[1]	15	15	15	15	15	15
	30	30	30	30	30	30
Retail Equipment Cost (2022$)[2]	90	90	85	85	85	85
	240	240	340	340	340	340
Total Installed Cost (2022$)[3]	150	150	390	390	390	390
	320	320	1,190	1,190	1,190	1,190
Annual Maintenance Cost (2022$)[4]	-	-	-	-	-	-

1. Assumes similar lifetime to Electric Furnaces on the basis that both products have heating elements that burn out and lead to product failure.
2. The lower bound of the equipment costs represents the average retail price listed at the typical capacity for electric baseboard heaters through a retailer website. The upper bound represents the average retail price for compact recessed electric wall heaters at the same capacity.
3. Range represents the estimated minimum and maximum installation costs.
4. Maintenance costs are negligible.

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Residential Electric Resistance Unit Heaters

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- Electric resistance unit heaters include electric wall and baseboard heaters. Plug-in space heaters are not included.
- There are currently no federal efficiency requirements for electric resistance unit heaters.
- According to preliminary RECS data released May 2022, electric resistance unit heaters are the main source of space heating in approximately 8.25 million U.S. homes or about 7%.
- Electric heaters range in capacity from 500 to 2,500 watts (1.7 to 8.5 kBtu/h), with 1,500 watts (5.1 kBtu/h) being the most typical for units on the market.
- Electric resistance heating is considered 100% energy efficient; all incoming electric energy is converted to heat.

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Residential Central Air Conditioners – North (Not Hot-Dry or Hot-Humid)

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Higher typical efficiencies with the same costs as ref. case despite increased efficiency.

DATA	2015	2020	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
SEER[1]	12.5	13.9	13.0	14.1	15.0	17.0	14.1	16.0	17.0	15.0	17.0	15.5	17.0	15.5	17.0
SEER2[2]	11.9	13.2	NA	13.4	NA	16.2	13.4	15.2	16.2	14.3	16.2	14.7	16.2	14.7	16.2
Average Life (y)	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	2,410	2,670	2,580	2,700	3,110	3,950	2,680	3,750	3,950	2,760	3,950	2,760	3,950	2,760	3,950
Total Installed Cost (2022$)	4,000	4,300	5,250	5,320	5,520	5,980	5,310	5,880	5,980	5,350	5,980	5,350	5,980	5,350	5,980
Annual Maintenance Cost (2022$)[3]	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150

1. Values shown are for split-system units in the 36 kBtu/h (3-ton) size class. Costs and efficiency levels are for "coil-only" systems, meaning they do not include a blower. Note blower-coil systems were analyzed for residential air-source heat pumps, which is why the "High" SEER levels are higher for heat pumps than for air conditioners.
2. In 2023, new energy conservation standards for Residential Central Air Conditioners and Heat Pumps took effect. The new standards specify a different metric for central air conditioners (SEER2). SEER to SEER2 conversions were determined using the RESNET website.
3. Annual maintenance include preventative maintenance and services provided by HVAC professionals for maintaining product operation. Examples include, calibrate and level thermostat, clean filters, clean indoor and condenser coil, flush/treat condensate drain with anti-algae, inspect condenser coil, monitor operating pressure of refrigerant, inspect fan blade, etc.

Note:
The previous standard went into effect in January 2015. The current standard went into effect in January 2023.
ENERGY STAR V. 5.0 went into effect in September 2015. ENERGY STAR V. 6.1 went into effect in January 2023.
Ranges represent the span of typical values for a given parameter.

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Residential Central Air Conditioners – South (Hot-Dry and Hot-Humid)

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Higher typical efficiencies with the same costs as ref. case despite increased efficiency.

DATA	2015	2020	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
SEER[1]	13.0	14.4	14.0	14.6	15.0	17.0	15.1	16.0	17.0	15.5	17.0	16.0	17.0	16.0	17.0
SEER2[2]	12.4	13.7	NA	13.9	NA	16.2	14.3	15.2	16.2	14.7	16.2	15.2	16.2	15.2	16.2
Average Life (y)	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	2,410	2,760	2,680	2,850	3,110	3,950	3,110	3,750	3,950	3,190	3,950	3,190	3,950	3,190	3,950
Total Installed Cost (2022$)	4,000	4,390	5,310	5,390	5,520	5,980	5,520	5,880	5,980	5,570	5,980	5,570	5,980	5,570	5,980
Annual Maintenance Cost (2022$)[3]	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150

1. Values shown are for split-system units in the 36 kBtu/h (3-ton) size class. Costs and efficiency levels are for "coil-only" systems, meaning they do not include a blower. Note blower-coil systems were analyzed for residential air-source heat pumps, which is why the "High" SEER levels are higher for heat pumps than for air conditioners.
2. In 2023, new energy conservation standards for Residential Central Air Conditioners and Heat Pumps took effect. The new standards specify a different metric for central air conditioners (SEER2). SEER to SEER2 conversions were determined using the RESNET website.
3. Annual maintenance include preventative maintenance and services provided by HVAC professionals for maintaining product operation. Examples include, calibrate and level thermostat, clean filters, clean indoor and condenser coil, flush/treat condensate drain with anti-algae, inspect condenser coil, monitor operating pressure of refrigerant, inspect fan blade, etc.

Note:
The previous standard went into effect in January 2015. The current standard went into effect in January 2023.
ENERGY STAR V. 5.0 went into effect in September 2015. ENERGY STAR V. 6.1 went into effect in January 2023.
Ranges represent the span of typical values for a given parameter.

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- The previous standards took effect in 2015; amended standards for all product classes went into effect in January 2023.
  - Amended standards are based on new metrics (SEER2, EER2).
  - SEER2 values are generally expected to be lower than SEER because a higher external static pressure is required during testing, which reduces measured performance.
- Systems installed in the Southwest (CA, AZ, NM, and NV) must also meet an EER standard that varies by cooling capacity and system configuration.
- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more cost-effective variable speed technology) are expected to increase efficiency without substantially increasing costs.

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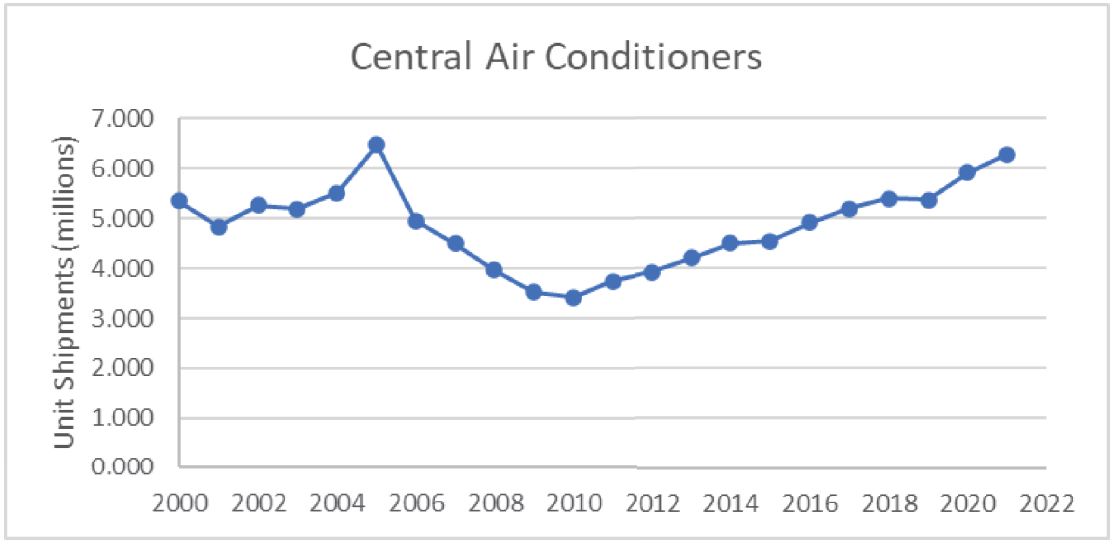
Annual shipments spiked at 6.5 million units in 2005 at the peak of the housing boom and just before more stringent Federal standards took effect in 2006. Annual shipments have been steadily increasing since 2010 and have almost reached the previous high in 2021.



Source: *AHRI*

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Residential Room Air Conditioners

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Increased efficiency with corresponding cost increases.

DATA	2015	2020	2022				2030[2]		2040[2]		2050[2]	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.2	High[1]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	10	10	10	10	10	10	10	10	10	10	10.0	10.0
CEER (Btu/Wh)	10.9	10.9	10.9	12.0	12.0	15.7	16.0	16.5	17.0	17.5	17.5	18.0
Average Life (y)	6	6	6	6	6	6	6	6	6	6	6	6
	13	13	13	13	13	13	13	13	13	13	13	13
Retail Equipment Cost (2022$)	560	330	330	340	340	450	450	450	460	460	470	470
	710	480	480	480	480	590	590	590	610	610	620	620
Total Installed Cost (2022$)	640	490	490	490	490	600	600	600	610	610	630	630
	830	630	630	640	640	750	750	750	760	760	770	770
Annual Maintenance Cost (2022$)[3]	0	0	0	0	0	0	0	0	0	0	0	0

1. RAC EERE 2022 NOPR has analysis for combined energy efficiency ratio (CEER) of 16 Btu/Wh, which represents variable speed room air conditioners. However, maximum CEER identified in DOE's Compliance Certification Database (CCD) in August 2022 was 15.7 Btu/Wh. Accordingly, the high CEER is estimated to be 15.7 for 2022 and beyond. Cost values for a representative unit with a CEER of 16 Btu/Wh were used.
2. The 2030, 2040, 2050 projections are estimated based on RAC EERE 2022 NOPR, which notes that in the absence of no new standards, room air conditioners with a CEER of 12 Btu/Wh are expected to have the maximum market share.
3. Maintenance costs are negligible per RAC EERE 2011 and RAC EERE 2022 NOPR.

Note:
All values are for the most common product class, Product Class 3 (without reverse cycle, with louvered sides, and 8,000 to 13,999 Btu/h).
The current standard went into effect in June 2014.
ENERGY STAR V. 4.2 went into effect in October 2015.
Ranges represent the span of typical values for a given parameter (for example, installed cost for equipment meeting the federal standard) not the highest and lowest available on the market.

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Residential Room Air Conditioners

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- Analyzed the most common type of room air conditioners: louvered sides (window air conditioners) without reverse cycle and having cooling capacity of 8,000–13,999 Btu/h (DOE Product Class 3).
- Federal standards for Product Class 3:
  - CEER ≥ 10.9 (beginning June 1, 2014)
- CEER incorporates energy use in cooling mode and standby and off modes.
- ENERGY STAR V. 4.2 criteria for Product Class 3:
  - CEER ≥ 12.0 (effective October 26, 2015)
- Efficiency improvements in room air conditioners are attained by:
  - Higher efficiency compressor and fan motors (including variable speed motors), and
  - An increased heat transfer area in the evaporator and condenser using larger heat exchangers, finer fin spacing, micro-channel heat exchangers, and similar design options.
- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more efficient motors and compressors, larger cross-section heat exchangers, adoption of variable speed technologies) are expected to increase efficiency with corresponding increases in cost.

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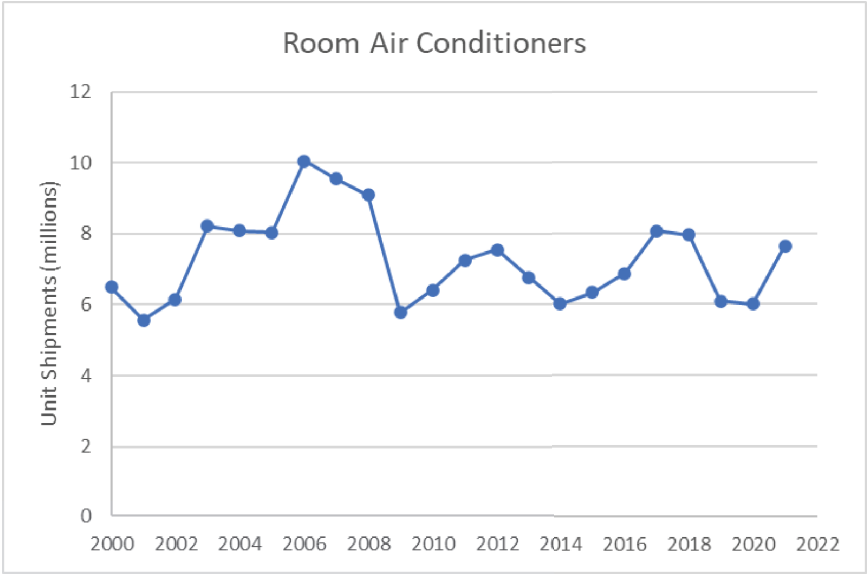
Annual shipments dropped sharply in 2009, likely due to the recession and an unusually cool summer in the Northeast. Sales have largely leveled off in the years since, fluctuating between 6 and 8 million.



Source: *RAC EERE 2022 NOPR*

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Residential Portable Air Conditioners

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Increased efficiency with corresponding cost increases.

DATA	2015	2020	2022[4]		2025		2030		2040		2050	
	Installed Base	Installed Base	Typical	High[5]	New Standard	High[5]	Typical	High[5]	Typical	High[5]	Typical	High[5]
Typical Capacity (kBtu/h)[1]	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
CEER[2]	5.6	5.6	5.5	7.6	6.7	7.6	7.8	8.8	8.9	10.1	10.2	11.6
Average Life (y)	7	7	7	7	7	7	7	7	7	7	7	7
	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)	700	700	700	810	760	810	810	810	820	820	830	830
Total Installed Cost (2022$)[3]	700	700	700	810	760	810	810	810	820	820	830	830
Annual Maintenance Cost (2022$)[3]	0	0	0	0	0	0	0	0	0	0	0	0

1. All values are for the average capacity for single-duct and dual-duct portable air conditioners available on the market.
2. CEER is calculated for typical capacity using the equation provided in PAC EERE 2020.
3. Installation and maintenance costs are negligible.
4. The 2022 Typical estimates are based on PAC EERE 2020, which estimated majority of the market to be at EL1 in 2022 for the no-new standards case, which translates to a CEER of 5.5 for this analysis.
5. All High values are based on the most-efficient models available in the market, as specified in PAC EERE 2020.

Note:
A final rule for portable air cleaners published in January 2020 with an effective date of January 2025.
Costs are interpolated from the costs presented in PAC EERE 2020.
Range for lifetime represents typical values.

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Residential Portable Air Conditioners

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- A final rule establishing new energy conservation standards for portable air conditioners published in January 2020 with an effective date of January 2025.
- The final rule outlined an equation-based conservation standard (in CEER) for both single-duct and dual-duct portable ACs, based on the seasonally adjusted cooling capacity (SACC)

$$\text{Minimum CEER} = \text{PR} \times \frac{\text{SACC}}{(3.7117 \times \text{SACC}^{0.6384})}$$

- Efficiency improvements in portable air conditioners are attained by:
  - Higher efficiency compressor and fan motors (including variable speed motors), and
  - An increased heat transfer area in the evaporator and condenser using larger heat exchangers, finer fin spacing, micro-channel heat exchangers, and similar design options.
- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more efficient motors and compressors, larger cross-section heat exchangers, adoption of variable speed technologies) are expected to increase efficiency with corresponding increases in cost.

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Residential Portable Air Conditioners

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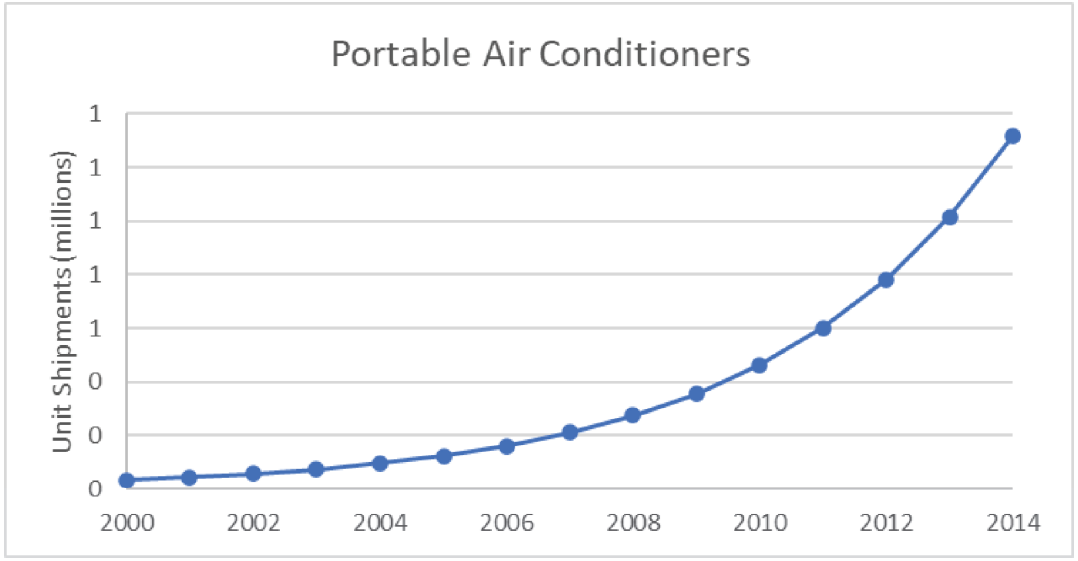
Annual shipments have seen an exponential growth through 2014. Shipments data since 2014 is not publicly available but it is expected that portable air conditioners shipments may have increased in recent years in response to indoor air quality concerns following COVID-19.



Source: *PAC EERE 2020*

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Residential Swamp Coolers

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Same as reference case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Air Flow Rate (CFM)	3,800	3,800	3,800	4,700	3,800	4,700	3,800	4,700	3,800	4,700
Power (Hp)	1/3	1/3	1/3	1/2	1/3	1/2	1/3	1/2	1/3	1/2
Average Life (y)[1]	10	10	10	10	10	10	10	10	10	10
	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)	960	960	960	1,100	960	1,100	960	1,100	960	1,100
Total Installed Cost (2022$)	1,360	1,360	1,360	1,540	1,360	1,540	1,360	1,540	1,360	1,540
Annual Maintenance Cost (2022$)	330	330	330	330	330	330	330	330	330	330

1. Average lifetime provided by major swamp cooler installer in the U.S. Southwest.

Note:
Efficiency values were determined based on a sample of window-mounted swamp coolers.
Lifetime range represents span of typical values.

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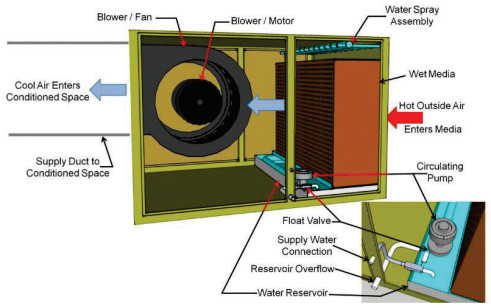
- Evaporative cooling (i.e., "swamp coolers") is a technology that takes advantage of water evaporation to cool incoming air. Energy is required to change water from a liquid to a vapor (i.e., the heat of vaporization), and in doing so, temperature of the air is reduced. Evaporative cooling is best suited for hot, dry climates.
- Swamp coolers come in a variety of different configurations, including centrally ducted units that are mounted outside a building or roof; window evaporative coolers that are window-mount units that pull in warm outdoor air, pass it through wet media to remove heat, and blow out the cooled air; or portable plug-in units. Window units were considered for this analysis due to the high model share count on distributor websites.
- The U.S. Environmental Protection Agency (EPA) has cautioned against using swamp coolers in wildfire-impacted areas in smoky conditions because it can result in more smoke bring brought inside.
- Swamp coolers are not a DOE-covered product.
- Swamp cooler metrics include power of the fan/blower, measured in horsepower (hp), and air flow rate, measured in cubic feet per minute (CFM).



Single-inlet direct swamp cooler. Source: PNNL

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Residential Air-Source Heat Pumps

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Higher typical efficiencies with the same costs as reference case despite increased efficiency

DATA	2015	2020	2022				2023				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	ENERGY STAR Cold Climate Criteria	High[4]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
SEER (Cooling)[1]	13.1	15.3	14.0	15.3	15.0	22.6	15.0	16.0	NA	22.6	16.5	22.6	17.0	22.6	17.5	22.6
SEER2[2]	12.4	14.5	NA	14.5	NA	21.5	14.3	15.2	15.2	21.5	15.7	21.5	16.2	21.5	16.6	21.5
HSPF (Heating)[1]	7.9	8.6	8.2	8.6	8.5	12.4	8.8	9.2	NA	12.4	9.3	12.4	9.3	12.4	9.4	12.4
HSPF2[2]	6.7	7.3	NA	7.3	NA	10.6	7.5	7.8	8.1	10.6	7.9	10.6	7.9	10.6	8.0	10.6
Average Life (y)	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
Retail Equipment Cost (2022$)[1]	3,290	4,270	3,970	4,270	4,110	6,740	4,110	4,380	4,380	6,740	4,380	6,740	5,000	6,740	5,100	6,740
Total Installed Cost (2022$)[1]	5,790	6,880	6,730	6,880	6,810	8,620	6,810	6,940	6,940	8,620	6,940	8,620	7,240	8,620	7,330	8,620
Annual Maintenance Cost (2022$)[3]	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150

1. Values shown are for split-system units in the 36 kBtu/h (3-ton) size class. Costs and efficiency levels are for "blower-coil" systems, meaning they include a blower. Note coil-only systems were analyzed for residential central air conditioners, which is why the "High" SEER levels are higher for heat pumps than for air conditioners.
2. In 2023, new energy conservation standards for Residential Central Air Conditioners and Heat Pumps took effect. The new standards specify different metrics for Air-Source Heat Pumps (SEER2 and heating seasonal performance factor 2 (HSPF2)). SEER to SEER2 and HSPF to HSPF2 conversions were determined using the RESNET website.
3. Annual maintenance include preventative maintenance and services provided by HVAC professionals for maintaining product operation. Examples include, calibrate and level thermostat, clean filters, clean indoor and condenser coil, flush/treat condensate drain with anti-algae, inspect condenser coil, monitor operating pressure of refrigerant, inspect fan blade, etc.
4. High costs derived from developing a cost-efficiency curve between retail/installed costs and SEER.

Note:
The previous standard went into effect in January 2015. The current standard went into effect in January 2023.
ENERGY STAR V. 5.0 went into effect in September 2015. ENERGY STAR V. 6.1 went into effect in January 2023.
Ranges represent the span of typical values for maintenance costs.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.88, 2, 1).

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- The previous standards took effect in 2015; amended standards for all product classes went into effect in January 2023.
  - Amended standards are based on new metrics (SEER2, EER2, HSPF2).
  - SEER2 values are generally expected to be lower than SEER because a higher external static pressure is required during testing, which reduces measured performance.
- High efficiency cooling does not necessarily correlate with high efficiency heating. The range of SEER–HSPF combinations is very broad.
- Heat pumps are generally sized to meet the cooling load of the house. When the heating load exceeds heat pump heating capacity, electric resistance heat is used to supplement.
- Variable-speed compressors improve efficiency of heat pumps by reducing cyclic losses and by operating above their nominal speed, boosting heating capacity, and reducing the need for supplementary electric resistance heat.
- In addition to meeting the SEER2 and HSPF2 requirements, air source heat pumps must demonstrate low ambient performance to earn the Cold Climate designation by meeting the following:
  - Coefficient of Performance (COP) at 5 degrees Fahrenheit (°F) ≥ 1.75, measured in accordance with Appendix M1 $H4_2$ test
  - Percent of Heating Capacity at 5 °F ≥ 70% of that at 47 °F, with the 5 °F capacity measured per Appendix M1 $H4_2$ test and the 47 °F capacity measured as the nominal heating capacity per Appendix M1 (i.e., from the Appendix M1 $H1_N$ test for units having a variable-speed compressor where the compressor speed shall be the maximum speed that the system controls would operate at 47 °F, otherwise from the Appendix M1 $H1_2$ test)
  - Perform a controls verification procedure (CVP) to confirm that the above performance metrics measured at the Appendix M1 low ambient test point at 5 °F are achieved by the native controls operating as they would in a customer's home
- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more cost-effective variable speed technology) are expected to increase efficiency without substantially increasing costs.

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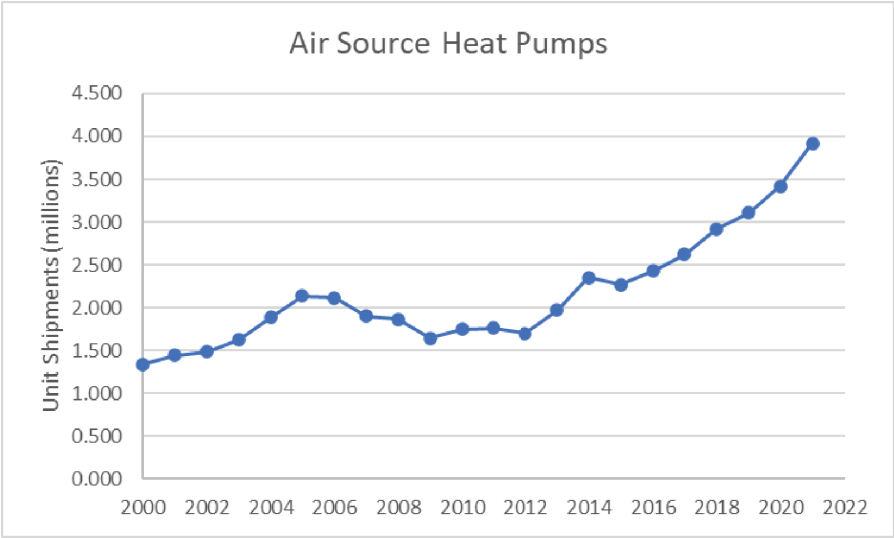
From 2000 to 2005 annual shipments increased nearly 60% to 2.1 million units, then dropped and leveled off around 1.7 million units. In 2014 annual shipments surpassed the 2005 peak and have been increasing uniformly since then.



Source: *AHRI*

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Residential Central Air Conditioners and Air-Source Heat Pumps

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- Principal energy efficiency drivers for central air conditioners and heat pumps:
  - Heat exchanger (surface area, number of tube rows)
  - Compressor (type and single-stage vs. two-stage vs. variable-speed operation)
  - Fan motor choices (PSC vs. ECM fan motors on inside and outside)
  - Control choices (i.e., piston, thermal, and electronic expansion valves)
- When the heat pump or air conditioner's capacity exceeds the heating or cooling load, the unit starts and stops more frequently, causing wear and tear on the components and an overall loss of efficiency. Multi-stage and/or variable-speed compressors can help, as does sophisticated refrigerant management.
- Typical high-efficiency unit (≥ 16 SEER) has very large heat exchanger, ECM evaporator fan motor, and two-stage scroll compressor.
- Variable-speed compressor technology typically leads to a significant SEER boost, making possible high-SEER condensing units with smaller heat exchangers, and thus, smaller enclosures.
- Efficiency levels > 21 SEER made possible through combining existing large heat exchangers with variable-speed compressors, ECM fan motors, and electronic expansion valves.

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Residential Ductless Mini-Split Air-Source Heat Pumps

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Same as reference case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)[1]	12	12	12	12	12	12	12	12	12	12
SEER	16.0	16.0	21.9	33.1	21.9	33.1	21.9	33.1	21.9	33.1
EER	12.5	12.5	13.0	19.1	13.0	19.1	13.0	19.1	13.0	19.1
HSPF	10.0	10.0	11.1	14.0	11.1	14.0	11.1	14.0	11.1	14.0
Average Life (y)[2]	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3
Retail Equipment Cost (2022$)	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580	1,580
Total Installed Cost (2022$)	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030	2,030
Annual Maintenance Cost (2022$)[3]	100	100	100	100	100	100	100	100	100	100

1. Representative capacity determined from most frequent capacity in AHRI database
2. Assumed same lifespan and maintenance cost as air-source heat pumps given the technology is similar between air-source and ductless mini-split heat pumps, and ductwork itself is not expected to fail.
3. Annual maintenance covers the same services identified for air-source heat pumps.

Note:
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.88, 2, 1).

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Residential Ductless Mini-Split Air-Source Heat Pumps

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- Ductless systems can be useful in "spot cooling" certain high-use areas of a home, such as a living room, bedroom, or office.
- Mini-split heat pumps are generally more efficient (often > 20 SEER) and smaller in cooling capacity (often ≤ 24 kBtu/h) compared to split-system heat pumps.
  - A mini-split heat pump could be equal in capacity and efficiency to a split-system heat pump as there are no inherent design changes between split-system and mini-split heat pumps, aside from the ductwork. Mini-split heat pumps tend to be more efficient and smaller in capacity due to their prevalence for spot cooling, but the same technologies are used between the two product categories.
- Due to the similarities in design, cost estimations were determined based on smaller capacity (24 kBtu/h) split-system heat pumps and Gordian's RSMeans Data – Building Construction Costs 2023. Efficiency data was analyzed using the AHRI directory, which provides disaggregation of data on the basis of ducted and ductless heat pumps.
- Annual maintenance covers the same services identified for air-source heat pumps.

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Residential Ground-Source Heat Pumps

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Same typical efficiencies with the lower costs as ref. case despite same efficiency.

DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.2	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	36	36	36	36	36	36	36	36	36	36	36	36
COP (Heating)[1]	3.1	3.7	3.2	3.6	3.6	4.5	3.6	4.5	3.6	4.5	3.6	4.5
EER (Cooling)[2]	13.3	17.3	14.1	17.3	17.1	22.0	17.3	22.0	17.3	22.0	17.3	22.0
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8	8
	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	4,650	5,470	4,820	5,470	5,410	6,530	4,920	5,880	4,920	5,880	4,920	5,880
Total Installed Cost (2022$)	14,060	14,880	14,230	14,880	14,880	15,940	13,390	14,350	13,390	14,350	13,390	14,350
	22,290	23,120	22,470	23,120	23,120	24,170	20,810	21,750	20,810	21,750	20,810	21,750
Annual Maintenance Cost (2022$)	90	90	90	90	90	90	90	90	90	90	90	90

1. COP values listed are assessed at a "ground loop" test condition, which is representative of closed loop ground source heat pumps (GSHP) operating conditions. However, DOE sets standards at a "water loop" test condition. The AHRI directory lists COP ratings at both sets of test conditions and is used to convert between them where necessary.
2. EER values listed are assessed at a full-load "ground loop" test condition, which is representative of closed loop GSHP operating conditions. However, DOE sets standards at a full-load "water loop" test condition. The AHRI directory lists EER ratings at all sets of test conditions and is used to convert between them where necessary.

Note:
Residential and commercial GSHPs are very similar - the main difference in data presented is the different capacity (3-ton vs. 4-ton) and slightly higher installation costs for commercial GSHP. DOE does not distinguish between residential and commercial units in its regulations.
Current standards went into effect on October 9, 2015. COP and EER ratings are converted from the "water loop" test condition to "ground loop."
ENERGY STAR V. 3.2 went into effect January 1, 2012.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (17.04, 1.64, 1).

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Residential Ground-Source Heat Pumps

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- Heating COP does not correlate with cooling EER.
- The ENERGY STAR criteria for water-to-air ground-source heat pumps are:

Type	Heating COP	Cooling EER
Closed Loop	3.6	17.1
Open Loop	4.1	21.1
Direct Expansion	3.6	16

- The most common GSHP is a closed-loop system in which water or an anti-freeze solution is circulated through plastic pipes buried underground. Open loop systems that employ ground water or surface water (e.g., open well, pond, lake) are used in some parts of the country, but water supply and water quality issues impose limitations on such applications.
- Installation cost is for a closed loop system and includes necessary accessories. The ground loop heat exchanger represents a majority of the installation cost. Installed costs for these systems vary widely.
- Variable speed ECMs improve performance on high-end models.
- Advanced Case: GSHP are already highly efficient and have not changed much in terms of efficiency in recent years. With increased R&D, it is anticipated that the equipment and installation costs will be reduced over time, but efficiency will likely stay the same.

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Residential Natural Gas Heat Pumps

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Same as reference case

DATA	2015	2020	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (kBtu/h)	60	60	60	60	60	60
COP (Heating)	1.3	1.3	1.3	1.3	1.3	1.3
COP (Cooling)	0.6	0.7	0.7	0.7	0.7	0.7
Annual Electric Use (kWh/y)[1]	1,500	1,500	1,500	1,500	1,500	1,500
Average Life (y)[2]	12	12	12	12	12	12
	18	18	18	18	18	18
Retail Equipment Cost (2022$)[2]	12,940	12,940	12,940	12,940	12,940	12,940
	14,350	14,350	14,350	14,350	14,350	14,350
Total Installed Cost (2022$)[2]	14,700	14,700	14,700	14,700	14,700	14,700
	17,290	17,290	17,290	17,290	17,290	17,290
Annual Maintenance Cost (2022$)	200	200	200	200	200	200

1. Annual electric use accounts for the electricity consumption of components such as the heat pump fan.

Note:
Ranges represent the span of typical values observed in the market.

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Residential Natural Gas Heat Pumps

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- Residential natural gas heat pumps are not currently subject to DOE regulations. The California Energy Commission's (CEC) Title 24, Part 6 Section 112 does indicate cooling efficiency requirements for natural gas heat pumps.
- Natural gas heat pumps are much more popular in other parts of the world, such as Europe. Gas-fired cooling equipment currently comprises less than 1% of the residential air conditioning/heat pump market in the U.S.
- Currently, Robur is the predominant manufacturer of residential-sized natural gas heat pumps with sales operations in the U.S.. Robur units are 5-ton nominal cooling capacity, a size typically associated with larger homes. Since only one product is available, no mid-level or high efficiency categories are included in this analysis.
- The data represents air-source absorption heat pumps. Gas engine-driven vapor compression heat pumps are available in other parts of the world; York formerly offered the Triathlon gas engine-driven heat pump in the U.S. It is possible to couple either technology to the ground (ground-source) rather than the atmosphere (air-source).
- The absorption heat pump is a gas-fired, ammonia-water absorption cycle, combined with a high-efficiency low-pressure boiler integrated into one outdoor unit.
- The cooling efficiency of a gas-fired air-source absorption heat pump is considerably lower than for an electric air-source heat pump. Heating efficiency of an air-source heat pump (electric or gas-fired absorption) decreases as outdoor temperature decreases; however, the gas-fired absorption heat pump recovers waste heat from the combustion process to improve heating efficiency.

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Residential Cordwood Stoves

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Same as reference case

DATA	2015[1]	2020[2]	2022[3]		2030[4]		2040[4]		2050[4]	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	50	50	50	50	50	50	50	50	50	50
Efficiency (Non-Catalytic) (HHV)[5]	63	71	71	80	71	80	71	80	71	80
Efficiency (Catalytic) (HHV)[5]	72	76	76	81	76	81	76	81	76	81
Average Life (y)	12	12	12	12	12	12	12	12	12	12
	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$) (Non-Catalytic)	2,880	1,670	1,670	2,300	1,670	2,300	1,670	2,300	1,670	2,300
Retail Equipment Cost (2022$) (Catalytic)	3,540	3,040	3,040	3,830	3,040	3,830	3,040	3,830	3,040	3,830
Total Installed Cost (2022$) (Non-Catalytic)[6]	8,290	7,090	7,090	7,710	7,090	7,710	7,090	7,710	7,090	7,710
Total Installed Cost (2022$) (Catalytic)[6]	8,950	8,460	8,460	9,240	8,460	9,240	8,460	9,240	8,460	9,240
Annual Maintenance Cost (2022$) (Non-Catalytic)[7]	190	190	190	190	190	190	190	190	190	190
Annual Maintenance Cost (2022$) (Catalytic)[7]	280	280	280	280	280	280	280	280	280	280

1. For 2015, assumed EPA default efficiencies, which were used by EPA to approximate the efficiency of stoves before the 2015 EPA rule required efficiency testing.
2. For 2020, assumed same efficiencies as estimated for 2022 given the most recent EPA rule went into effect in May 2020.
3. The 2022 High value is the highest EPA certified efficiency. The 2022 Typical value is the average of EPA certified efficiencies.
4. For 2030-2050, it is assumed that the same conditions as current would persist because no impending efficiency requirements are expected from EPA, given recency of 2020 rulemaking and current market factors.
5. Efficiency includes combustion and heat transfer efficiency and is based on the higher heating value (HHV) of the fuel.
6. Installed costs include the cost of hearth and stainless-steel chimney liner - materials and labor.
7. For catalytic stoves, annual maintenance cost includes periodic cost of replacing the catalytic combustor.

Note:
The range for average life represents the span of typical values.

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Residential Cordwood Stoves

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- Residential cordwood stoves that must meet EPA particulate limits fall into two broad classes based on whether they use a catalyst for air treatment. Catalytic wood stoves use a catalytic combustor to reduce emissions from the combustion air. Non-catalytic wood stoves use baffles and introduce secondary air above the flames to enable more complete combustion and reduce emissions.
- In 2015, EPA published an update to its New Source Performance Standards (NSPS), decreasing the emissions limit (previously set by 1988 EPA rule) to 4.5 grams per hour (g/h) for both catalytic and non-catalytic stoves. The new rule did not institute efficiency standards but required that manufacturers test and certify the efficiency of their stoves. This standard took full effect on January 1, 2016.
- In 2020, the NSPS limit for new room heaters was lowered to 2.5 g/h if tested with cord wood.
- Prior to the 2015 rule, manufacturers could either submit efficiency data from laboratory testing or certify with the default efficiency value designated by EPA. EPA's default efficiency values were 63% for non-catalytic wood stoves and 72% for catalytic wood stoves. Under this system, few manufacturers submitted efficiency test data to EPA.
- Multiple test standards are commonly used to assess stove efficiency, and data from product literature does not generally identify the efficiency test method.
- It is not possible to determine performance trends based on construction or configuration (e.g., cast iron vs. plate steel, powered blowers vs. no blowers, etc.) trends in specific equipment type or construction based on published efficiencies. Further, EPA certification data shows no significant relationship between emissions and heating efficiency.
- Cordwood stoves require chimneys for venting combustion gases. Whether conventional masonry chimneys are used or metal chimney liners, these add considerable cost to the overall system. Accordingly, installed costs can be twice that of the wood stove itself.

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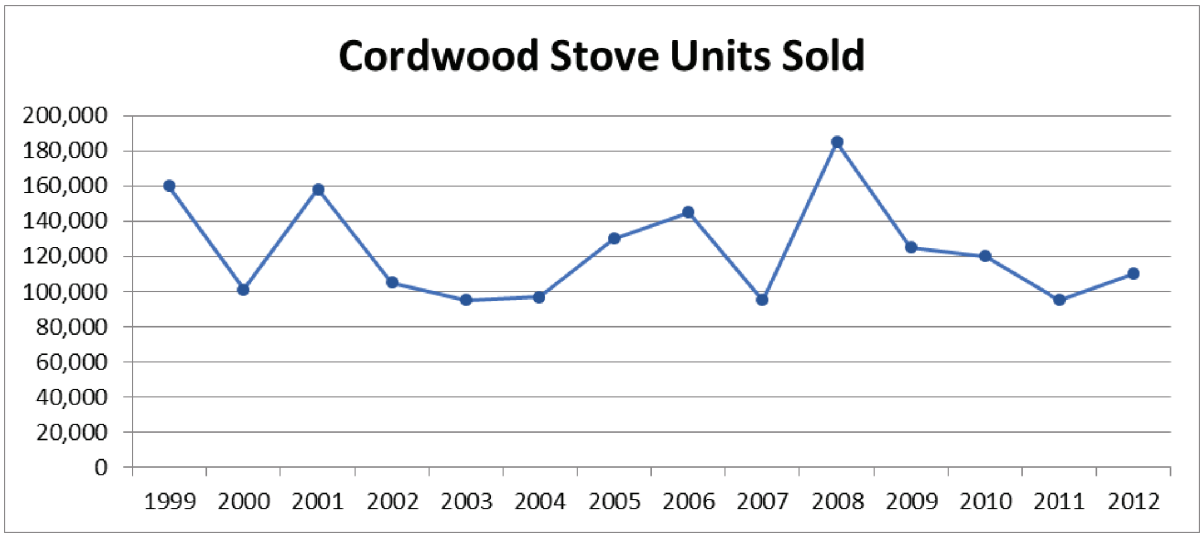
Cordwood stove shipments have averaged 123,000 per year since 1999 and have fluctuated approximately in accordance with fuel oil costs.



Source: *HPBA, no post-2012 sales data was publicly available at time of publication.*

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Residential Wood Pellet Stoves

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Same as reference case

DATA	2015[1]	2020[2]	2022[3]		2030[4]		2040[4]		2050[4]	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	50	50	50	50	50	50	50	50	50	50
Efficiency (HHV)[5]	70	73	73	85	73	85	73	85	73	85
Annual Electricity Consumption (kWh)[6]	600	600	600	600	600	600	600	600	600	600
Average Life (y)	12	12	12	12	12	12	12	12	12	12
	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	3,900	3,120	3,120	4,000	3,120	4,000	3,120	4,000	3,120	4,000
Total Installed Cost (2022$)[7]	5,550	4,520	4,520	5,400	4,520	5,400	4,520	5,400	4,520	5,400
Annual Maintenance Cost (2022$)	310	310	310	310	310	310	310	310	310	310

1. For 2015, assumed EPA default efficiencies, which were used by EPA to approximate the efficiency of stoves before the 2015 EPA rule required efficiency testing.
2. For 2020, assumed same efficiencies as estimated for 2022 given the most recent EPA rule went into effect in May 2020.
3. The 2022 High value is the highest EPA certified efficiency. The 2022 Typical value is the average of EPA certified efficiencies.
4. For 2030-2050, it is assumed that the same conditions as current would persist because no impending efficiency requirements are expected from EPA, given recency of 2020 rulemaking and current market factors.
5. Efficiency includes combustion and heat transfer efficiency and is based on the HHV of the fuel.
6. The annual electric consumption estimates assume 6 months/year @ 100kW/mo based on DOE estimates.
7. Installed cost includes cost of hearth and vent pipe - materials and labor.

Note:
The range for average life represents the span of typical values.

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Residential Wood Pellet Stoves

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- In 2015, EPA published an update to its NSPS, limiting emissions for wood pellet stoves to 4.5 g/h. Prior to the 2015 EPA rule, most pellet stoves were exempt from EPA's NSPS requirements. The new rule did not institute efficiency standards but required that manufacturers test and certify the efficiency of their stoves. This standard took full effect on January 1, 2016.
- Prior to the 2015 rule, manufacturers could either submit efficiency data from laboratory testing or certify with the default efficiency value designated by EPA. EPA's default efficiency values were 63% for non-catalytic wood stoves and 72% for catalytic wood stoves. Under this system, few manufacturers submitted efficiency test data to EPA.
- Multiple test standards are commonly used to assess stove efficiency and data from product literature does not generally identify the efficiency test method.
- It is not possible to determine performance trends based on construction or configuration (e.g., cast iron vs. plate steel, powered blowers vs. no blowers, etc.) trends in specific equipment type or construction based on published efficiencies. Further, EPA certification data shows no significant relationship between emissions and heating efficiency.
- Wood pellet stoves may be able to be direct vented to the outdoors, eliminating the need for a chimney. This reduces the overall system cost as compared to a cord wood stove. However, they do use electricity to power the pellet feeder, the combustion air fan, and the blower. In the event of a power outage, a pellet stove can not operate without some back-up source of electricity (e.g., battery) .

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Residential Wood Pellet Stoves

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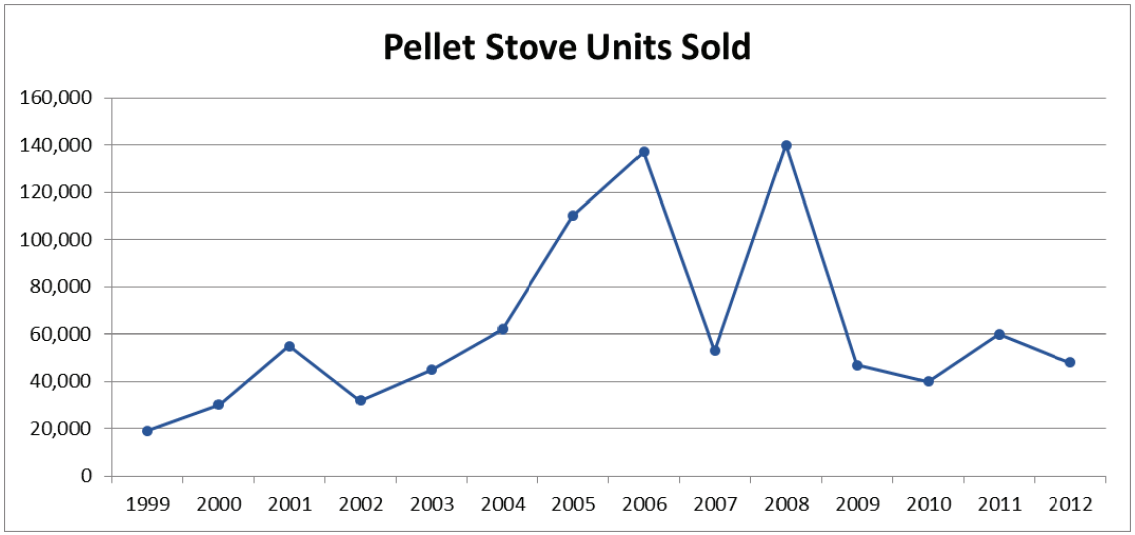
Wood pellet stove shipments grew substantially in the 2005 – 2008 time period but have averaged only 40,000 – 60,000 units since that time.



Source: *HPBA, no post-2012 sales data was publicly available at time of publication.*

Residential Water Heating

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Residential Gas-Fired Storage Water Heaters

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Increased typical efficiencies with associated increase in costs to reflect condensing units.

DATA	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	40	40	40	40	40	40	40	40	40	40	40	40	40
Uniform Energy Factor (UEF)[1]	0.58	0.63	0.61	0.61	0.66	0.84	0.83	0.78	0.84	0.78	1.33	0.78	1.33
Average Life (y)	13	13	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
Retail Equipment Cost (2022$)	590	880	420	420	490	720	700	420	720	420	720	420	720
	650	1,410	990	990	1,110	1,650	1,590	990	1,650	990	1,650	990	1,650
Total Installed Cost (2022$)	1,240	1,650	740	740	800	1,140	1,130	740	1,140	740	1,140	740	1,140
	1,240	2,880	1,690	1,690	1,850	3,130	3,160	1,690	3,130	1,690	3,130	1,690	3,130
Annual Maintenance Cost (2022$)[2]	20	20	20	20	20	20	20	20	20	20	20	20	20

1. Analysis is based on an average of medium and high draw pattern units, as this is most reflective of the market.
2. Maintenance includes manufacturer recommendation for the water heater to be drained and flushed annually to minimize deposition of sediment, maintain operating efficiency, and prolong product life. Available evidence indicates that this is performed in 10% of households.

Note:
Ranges represent the span of typical values.
Current standards went into effect April 16, 2015.
ENERGY STAR V. 4.0 went into effect January 5, 2022
ENERGY STAR V. 5.0 will go into effect April 18, 2023
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.1, 1.76, 1).

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Residential Gas-Fired Storage Water Heaters

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
≥ 20 gal and ≤ 55 gal	Very Small	UEF=0.3456-(0.002*Gal)	No models on the market	NA
	Low	UEF=0.5982-(0.0019*Gal)	0.54 for a 29-gallon water heater	NA
	Medium	UEF=0.6483-(0.0017*Gal)	0.58 for a 38-gallon water heater	0.64
	High	UEF=0.692-(0.0013*Gal)	0.64 for a 48-gallon water heater	0.68
> 55 gal and ≤ 100 gal	Very Small	UEF=0.647-(0.0006*Gal)	No models on the market	NA
	Low	UEF=0.7689-(0.0005*Gal)	No models on the market	NA
	Medium	UEF=0.7897-(0.0004*Gal)	No models on the market	0.78
	High	UEF=0.8072-(0.0003*Gal)	No models on the market	0.80

- There are currently no models on the market above 55 gallons (gal) due to the high UEF, which would require using condensing or gas-fired heat pump (e.g., absorption) technology to achieve.
- The cost of installation is typically $600 to $1200, which exceeds that of electric water heaters. This difference can be attributed to multiple differences; for example, gas-fired heaters require an extra 1.5 hours of labor for 2 plumbers.
- Condensing units are high efficiency and use PVC venting instead of stainless-steel. Condensing units also use an electrical supply for electronic ignition and power venting. Some building codes require condensate neutralizer filters.
- Advanced Case: Condensing gas-fired storage water heaters are expected to dominate the market by 2030, with corresponding price increases.

[1]Energy Conservation Standards for Residential Water Heaters. 10 CFR 430.32(d).

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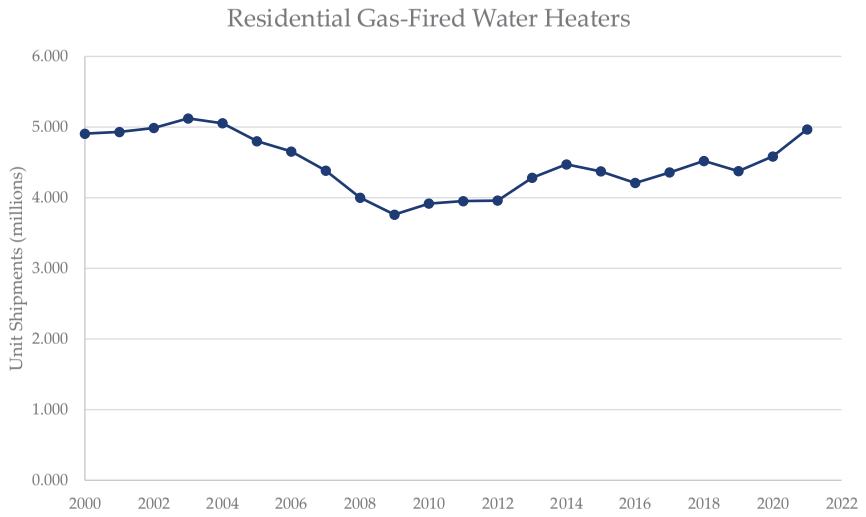
Shipments were flat at 5 million units per year through 2004, then declined gradually over 5 years to a new plateau at 4 million units until rising again back to 5 million units in 2021.



Source: *AHRI*

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Residential Oil-Fired Water Heaters

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Same as Reference Case

DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	32	32	32	32	32	32	32	32	32	32	32
Uniform Energy Factor[1]	0.51	0.67	0.64	0.66	0.68	0.66	0.68	0.66	0.68	0.66	0.68
Average Life (y)	13	13	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Retail Equipment Cost (2022$)	1,590	1,880	1,380	1,400	1,480	1,400	1,480	1,400	1,480	1,400	1,480
	1,710	2,410	2,810	2,870	3,030	2,870	3,030	2,870	3,030	2,870	3,030
Total Installed Cost (2022$)	2,350	2,650	2,620	2,650	2,730	2,650	2,730	2,650	2,730	2,650	2,730
	2,470	3,350	4,050	4,120	4,280	4,120	4,280	4,120	4,280	4,120	4,280
Annual Maintenance Cost (2022$)[2]	210	210	210	210	210	210	210	210	210	210	210

1. Analysis is based on an average of medium and high draw pattern units, as this is most reflective of the market.
2. Oil-fired storage water heaters are typically cleaned and maintained under maintenance contracts. The annual cost of typical maintenance is based on maintenance contract prices from different oil-fired product suppliers as specified in the CWH EERE 2022 Preliminary Analysis.

Note:
Ranges represent span of typical values.
Current standards went into effect April 16, 2015.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (16.2, 1.70, 1).

Residential Oil-Fired Water Heaters

- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
≤ 50 gal	Very Small	UEF=0.2509-(0.0012*Gal)	No models on the market	NA
	Low	UEF=0.533-(0.0016*Gal)	No models on the market	NA
	Medium	UEF=0.6078-(0.0016*Gal)	No models on the market	NA
	High	UEF=0.6815-(0.0014*Gal)	0.64 for a 29-gallon water heater	NA

- There are no ENERGY STAR requirements for oil-fired storage water heaters.
- Annual shipments of residential oil-fired storage water heaters are approximately 4,000, which is less than 1% of shipments of residential gas-fired storage water heaters.
- Oil-fired storage water heaters often have smaller tanks with larger input ratings relative to natural gas-fired and electric storage water heaters.
- No condensing residential oil-fired storage water heaters currently exist in the U.S. market. Condensing oil-fired water heaters are generally not considered technologically feasible because the sulfur content in fuel oil leads to the condensate becoming corrosive.
- Residential oil-fired water heaters utilize power burners and have at least some level of electrical power consumption.
- The most efficient models on the market use a proprietary "turbo-flue" design to increase heat transfer to water.

[1]Energy Conservation Standards for Residential Water Heaters. 10 CFR 430.32(d).

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Residential Oil-Fired Water Heaters

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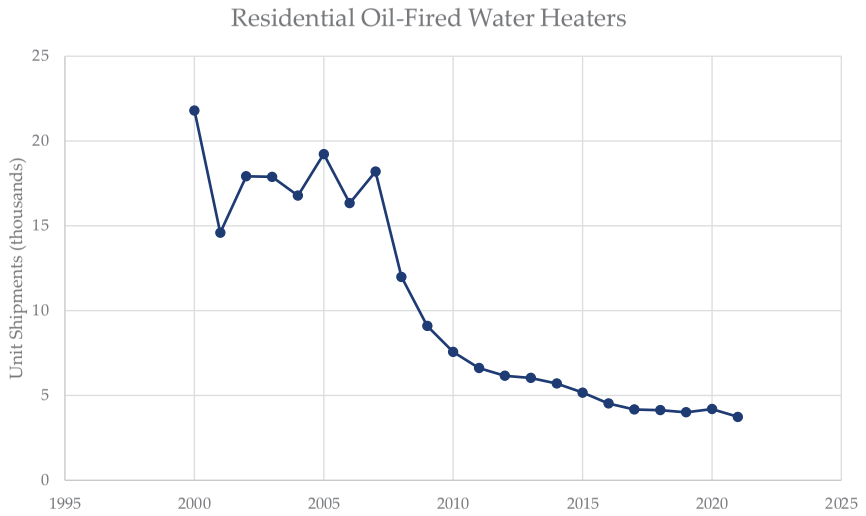
Shipments peaked at about 22,000 units in 2000 and have decreased since then, with an exponential decay occurring since 2007. Only about 4,000 units were shipped in 2021.



Source: *CWH EERE 2022 Preliminary Analysis*

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Residential Electric Resistance Storage Water Heaters

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Same as Reference Case

DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	50	50	50	50	50	50	50	50	50	50	50
Uniform Energy Factor[1]	0.88	0.93	0.92	0.92	0.93	0.92	0.93	0.92	0.93	0.92	0.93
Average Life (y)	13	13	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Retail Equipment Cost (2022$)	290	350	330	330	600	330	600	330	600	330	600
	530	650	760	760	850	760	850	760	850	760	850
Total Installed Cost (2022$)	590	710	500	500	550	500	550	500	550	500	550
	940	1,290	1,310	1,310	1,430	1,310	1,430	1,310	1,430	1,310	1,430
Annual Maintenance Cost (2022$)[2]	20	20	20	20	20	20	20	20	20	20	20

1. Beginning in 2016, the efficiency metric for water heaters changed from energy factor (EF) to UEF based on DOE test procedures. The UEF values for the installed base in 2015 are converted values equivalent to 0.90 EF. Analysis is based on an average of low and medium draw pattern units, as this is most reflective of the market.
2. Similar to gas-fired and oil-fired storage water heaters, manufacturers recommend that electric storage water heaters be drained and flushed annually to minimize deposition of sediment, maintain operating efficiency, and prolong product life. The available evidence indicates that this practice is done in 10% of households.

Note:
Ranges represent span of typical values.
Current standards went into effect April 16, 2015.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.7, 1.57, 1).

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Residential Electric Resistance Storage Water Heaters

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
≥ 20 gal and ≤ 55 gal	Very Small	UEF=0.8808-(0.0008*Gal)	No models on the market	2.00
	Low	UEF=0.9254-(0.0003*Gal)	0.92 for a 27-gallon water heater	2.00
	Medium	UEF=0.9307-(0.0002*Gal)	0.92 for a 45-gallon water heater	2.00
	High	UEF=0.9349-(0.0001*Gal)	0.93 for a 50-gallon water heater	2.00
> 55 gal and ≤ 120 gal	Very Small	UEF=1.9236-(0.0011*Gal)	No models on the market	2.20
	Low	UEF=2.0440-(0.0011*Gal)	No models on the market	2.20
	Medium	UEF=2.1171-(0.0011*Gal)	2.05 for a 58-gallon water heater	2.20
	High	UEF=2.2418-(0.0011*Gal)	2.15 for a 80-gallon water heater	2.20

- The federal standards for residential electric storage water heaters apply to both electric resistance storage water heaters and heat pump water heaters.
  - The Federal standard levels for the ≤ 55-gallon range are achievable through electric resistance and heat pump technology.
  - The Federal standards for the > 55-gallon range and all ENERGY STAR levels are only achievable through heat pump technology.
- Typical storage volumes range from 25-55 gallons for electric resistance storage water heaters and 45-80 gallons for heat pump water heaters (HPWHs).

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Residential Electric Resistance Storage Water Heaters

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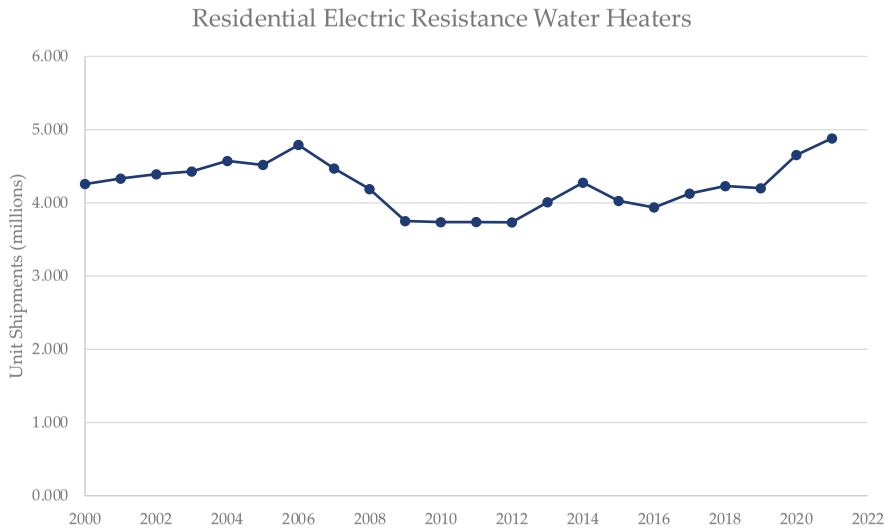
Shipments peaked in 2006 then dropped a total of 22 percent over three years. Shipments have gradually increased since then and were at the highest level in 2021.



Source: *AHRI*

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Residential Heat Pump Water Heaters

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Same as Reference Case

DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	50	50	50	50	50	50	50	50	50	50	50
Uniform Energy Factor[1]	2.05	3.28	3.33	3.30	3.73	3.33	3.73	3.33	3.73	3.33	3.73
Average Life (y)	13	13	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1	15.1
Retail Equipment Cost (2022$)[2]	1,290	1,410	630	630	670	630	670	630	670	630	670
	1,650	1,760	1,440	1,440	1,670	1,370	1,590	1,300	1,510	1,240	1,430
Total Installed Cost (2022$)[2]	1,710	1,880	870	870	980	870	980	870	980	870	980
	2,940	3,000	2,230	2,230	2,450	2,120	2,330	2,010	2,210	1,910	2,100
Annual Maintenance Cost (2022$)[3]	20	20	20	20	20	20	20	20	20	20	20

1. Analysis is based on an average of low and medium draw pattern units, as this is most reflective of the market.
2. It is expected that costs for HPWHs will decrease over time as these products become more common. This analysis estimates these cost decreases for the higher range of costs.
3. For heat pump water heater design options, DOE assumed higher maintenance cost to take into account annual cleaning of the air filter, preventative maintenance cost to check the evaporator and refrigeration system, inspection of the condensate withdrawal system, and replacement of the condensate neutralizer filter, if applicable. However, this maintenance is estimated to occur in only 10% of households, so overall maintenance cost is similar to that of other electric resistance water heaters.

Note:
Ranges represent span of typical values.
ENERGY STAR V. 4.0 went into effect January 5, 2022.
Assume same lifetime as electric resistance water heaters.

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Residential Heat Pump Water Heaters

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- Technology improvements have advanced efficiency and reliability, but the high first-cost and lack of awareness among consumers and contractors still precludes high-volume market penetration.
- New Federal standards that came into effect in April 2015 effectively mandate heat pump technology for electric storage water heaters with storage volume > 55 gallons.
- Integrated models are the most common configuration for residential HPWHs. Several major water heater manufacturers produce such models, and other competitors offer integrated or add-on units (for existing electric or indirect storage water heaters).
- Sales are estimated to be driven partly by rebates and tax credits at the utility, local, state, and Federal level.
- Resistive heating elements are virtually 100% efficient, but there is a jump in efficiency when heat pump technology is adopted because heat pumps' COP are usually between 2.5 and 4.
- Heat pumps raise the water temperature more slowly than resistive heating elements, so most models use backup resistive elements along with the heat pump when hot water demand is high. Most HPWHs allow the consumer to control whether resistive elements are used in periods of high demand (e.g., "hybrid mode" or "heat pump only mode").

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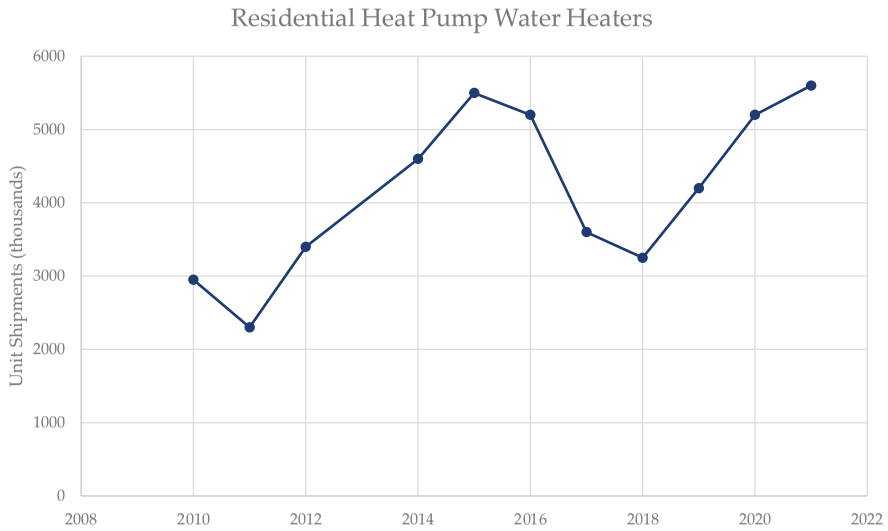
Shipments make up a small portion of electric resistance heaters, with a peak of only about 5,500 units, occurring in both 2015 and 2021.



Source: *ENERGY STAR*

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Residential Solar Water Heaters

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DATA	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	ENERGY STAR V. 4.0	Typical	Typical	Typical	Typical
Typical Capacity (ft^2)[1]	42	42	40	40	40	40	40
	65	65	54.4	54.4	54.4	54.4	54.4
Solar Uniform Energy Factor (SUEF)[2]	3.0	3.0	3.0	99.0	99.0	99.0	99.0
Average Life (y)	15	15	15	15	15	15	15
	30	30	30	30	30	30	30
Retail Equipment Cost (2022$)	7,710	7,710	6,430	6,430	6,430	6,430	6,430
Total Installed Cost (2022$)	10,650	10,650	8,060	8,060	8,060	8,060	8,060
Annual Maintenance Cost (2022$)[3]	80	80	80	80	80	80	80

1. Capacity selections are based on the range observed from medium draw units in the ENERGY STAR database. Medium draw represented the largest portion of units.
2. An SUEF of 3.0 is the required threshold for ENERGY STAR certification, yet a value of 99 was the most common observed SUEF among medium draw units. Note that an SUEF of 99 indicates that no backup heating was required for the applicable draw pattern, and all energy was provided by the solar collector. Since SUEF is a measure of hot water energy out divided by electrical or gas backup energy in, it will be infinite for cases where the collector provides all the hot water needed for the draw pattern – the Solar Rating and Certification Corporation's (SRCC's) OG-300 software is written to assign an SUEF of 99 to this case.
3. Annual maintenance is expected to be 0.5% to 1% of the total installation for 2022, 2030, 2040, and 2050.

Note:
ENERGY STAR V. 4.0 went into effect January 5, 2022.

Residential Solar Water Heaters

- Solar water heaters are not subject to federal energy conservation standards. The ENERGY STAR requirements are:

Applicable Products	Backup Fuel	ENERGY STAR Requirement	Test Method
Whole-home solar units	Gas	SUEF ≥ 3.0	ICC 900/SRCC 300-2020 Solar Thermal System Standard, Appendix A: Solar Uniform Energy Factor Procedure for Solar Water Heating Systems
	Electric	SEF ≥ 1.8	

- Solar water heaters can be either active or passive. An active system uses an electric pump to circulate the heat transfer fluid; a passive system has no pump. Most solar water heaters in the U.S. are the active type.
- Solar water heaters are also characterized as open loop (also called "direct") or closed loop (also called "indirect"). An open-loop system circulates household (potable) water through the collector. A closed-loop system uses a heat transfer fluid (water or diluted antifreeze, for example) to collect heat and a heat exchanger to transfer the heat to household water. Direct systems were observed as the most common product type and subject of this analysis.
- In 2020, stakeholders from the solar thermal industry developed the Solar Uniform Energy Factor (SUEF) Specification for solar water heaters to align with the UEF metric used by DOE for other water heating technologies.
- SUEF is also the metric used by the current ENERGY STAR Specification, and it replaced the Solar Energy Factor (SEF) metric.
- Over two-third of the current solar water heater market is in the southern or western U.S. (including Hawaii). A collector area of 42 square feet (ft^2) would be typical for these areas. Colder areas of the U.S. would require a larger collector (e.g., 65 ft^2).
- Installed costs are higher for colder areas where larger collectors are required. Costs also vary widely depending on collector quality, type of system, and site-specific characteristics.

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Residential Solar Water Heaters

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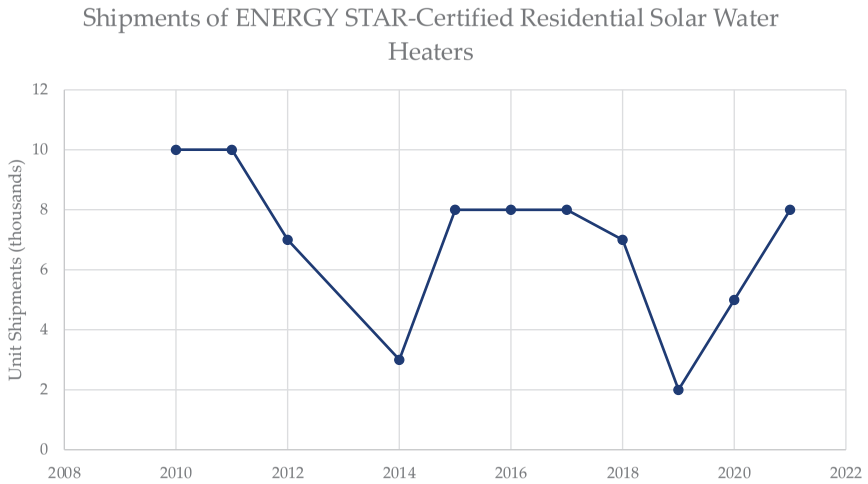
The shipments data below only represents ENERGY STAR-certified solar water heaters, as ENERGY STAR did not provide a market penetration rate. Solar water heaters have a small market share, with only 10,000 shipments at the peak in 2010 and 2011.



Source: *ENERGY STAR*

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Residential Gas-Fired Instantaneous Water Heaters

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Higher typical efficiency product with the same costs as ref. case despite increased efficiency

DATA	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	199	199	199	199	199	199	199	199	199	199	199	199	199
Uniform Energy Factor (UEF)[1]	0.81	0.89	0.81	0.92	0.87	0.97	0.95	0.96	0.97	0.96	0.97	0.96	0.97
Average Life (y)	19	19	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$)	1,410	1,180	430	580	580	610	610	580	610	580	610	580	610
	1,760	1,410	1,020	1,360	1,350	1,430	1,430	1,360	1,430	1,360	1,430	1,360	1,430
Total Installed Cost (2022$)	2,590	1,760	920	1,070	950	1,090	1,090	1,070	1,090	1,070	1,090	1,070	1,090
	3,820	3,350	2,860	3,160	3,140	3,230	3,220	3,160	3,230	3,160	3,230	3,160	3,230
Annual Maintenance Cost (2022$)[2]	90	90	90	90	90	90	90	90	90	90	90	90	90

1. Analysis is based on an average of low, medium, and high draw pattern units, as this is most reflective of the market.
2. Annual maintenance includes deliming to minimize deposition of sediment in the heat exchanger, maintain operating efficiency and prolong product life. Also includes additional tasks, including inspection of the ignition device, gas valve, controls, thermostat, and venting.

Note:
Current standards went into effect April 16, 2015.
ENERGY STAR V. 4.0 went into effect January 5, 2022.
ENERGY STAR V. 5.0 will go into effect April 18, 2023.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (21.3, 1.76, 1).

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Residential Gas-Fired Instantaneous Water Heaters

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- The equations for Federal Standards and the voluntary ENERGY STAR requirements, if applicable, are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes	ENERGY STAR
<2 gal and >50,000 Btu/h	Very Small	UEF=0.80	No models on the market	0.87
	Low	UEF=0.81	No models on the market	0.87
	Medium	UEF=0.81	0.81	0.87
	High	UEF=0.81	0.81	0.87

- The ENERGY STAR levels require the use of condensing technology.
- All of the major water heater manufacturers now offer an instantaneous water heater model.
- The maintenance costs include cleaning the water inlet filter and the heat exchanger of mineral deposits and replacing the water valve approximately once every five years for all instantaneous water heaters.
- When replacing a storage water heater with an instantaneous water heater, there are significant additional costs to upsize the gas supply line to ¾ inch from the typical ½ inch and change the venting.
- Advanced Case: Increased market incentives are expected to drive further adoption of condensing products, thereby raising the typical efficiency, while increased R&D is expected to improve cost.

[1]Energy Conservation Standards for Residential Water Heaters. 10 CFR 430.32(d).

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Residential Gas-Fired Instantaneous Water Heaters

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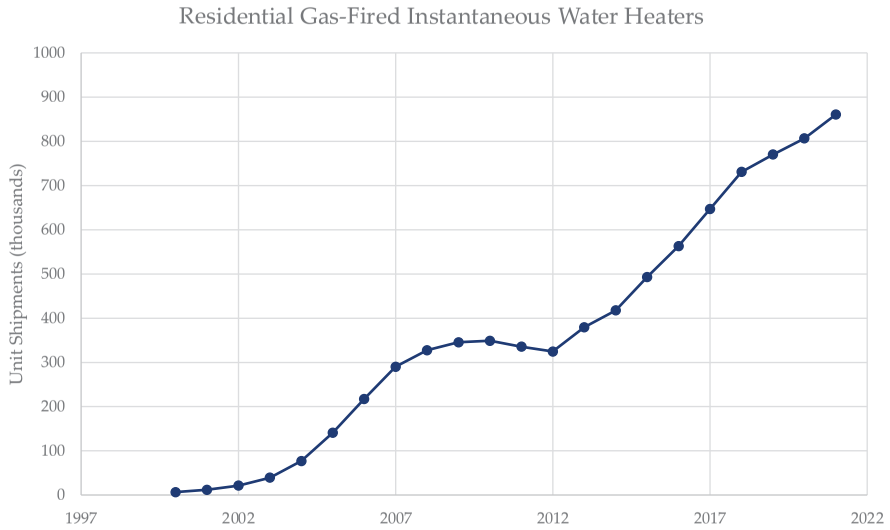
Shipments for Gas-Fired Instantaneous Water Heaters have grown steadily with nearly no shipments in 2000 and a peak of about 850,000 units in 2021.



Source: *CWH EERE 2022 Preliminary Analysis*

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Residential Electric Instantaneous Water Heaters

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DATA	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Representative Input Rate (kW)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Uniform Energy Factor (UEF)[1]	0.96	0.96	0.91	0.96	0.98	0.96	0.98	0.96	0.98	0.96	0.98
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$)	260	260	260	260	260	260	260	260	260	260	260
Total Installed Cost (2022$)	520	520	520	520	520	520	520	520	520	520	520
Annual Maintenance Cost (2022$)[2]	90	90	90	90	90	90	90	90	90	90	90

1. Analysis is based on an average of low, medium, and very small draw pattern units, as this is most reflective of the market.
2. Annual maintenance costs not provided in CWH EERE 2022 Preliminary Analysis. Maintenance costs determined from the following calculation: GIWH - (GSWH - ESWH) - i.e., the difference factor in maintenance between gas and electric storage heat pumps applied to gas instantaneous heat pumps.

Note:
Current standards went into effect April 16, 2015.
Assume same lifetime as gas-fired instantaneous water heaters.

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- The Federal standards are:

Volume Range	Draw Pattern	Federal standard[1]	Federal minimum UEF for typical sizes
<2 gal	Very Small	UEF=0.91	0.91
	Low	UEF=0.91	0.91
	Medium	UEF=0.91	No models on the market
	High	UEF=0.92	No models on the market

- Electric instantaneous water heaters use electric resistance heating elements to heat water when there is a demand. Resistive heating elements are virtually 100% efficient, and the small storage capacities of these products means that they do not lose significant amounts of heat to the environment.
- The federal standards for these products require UEFs of 0.91 for very small, low, and medium draw pattern models and 0.92 for high draw pattern models.
- Most products currently on the market are in the very small draw pattern or the low draw pattern because electric resistance elements can only supply a limited quantity of heat on an instantaneous basis due to circuit amperage limitations.
- Many products are designed for point-of-use applications, such that the water heater only supplies water to one faucet or showerhead.

Residential Appliances

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Residential Refrigerator-Freezers (Top)

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	19	19	19	19	19	19	19	19	19	19	19	19
Energy Consumption (kWh/y)[3]	512	401	411	401	370	358	370	358	370	358	370	358
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	670	750	740	750	760	760	750	760	750	760	750	760
Total Installed Cost (2022$)	670	750	740	750	760	760	750	760	750	760	750	760
Annual Maintenance Cost (2022$)[4]	10	10	10	10	10	10	10	10	10	10	10	10

1. Product Class 3 is used for this analysis (Refrigerator-freezers—automatic defrost with top-mounted freezer without through-the-door ice service and all-refrigerator—automatic defrost).
2. The volume shown here is the nominal total volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. The 2015 installed base energy consumption value is based on an adjusted volume of 21 cubic feet (ft^3). Energy consumption values for the 2020 installed base and 2022 and beyond are based on an adjusted volume of 22 ft^3, representing the current market.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics, ice maker), not replaceable components (e.g., water filters).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect in September 2014.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (10.26, 1.28, 5.13).

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Residential Refrigerator-Freezers (Side)

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	26	26	25	25	25	25	25	25	25	25	25	25
Energy Consumption (kWh/y)[3]	893	693	705	693	635	610	635	610	635	610	635	610
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	1,400	1,130	1,130	1,130	1,160	1,470	1,130	1,470	1,130	1,470	1,130	1,470
Total Installed Cost (2022$)	1,400	1,130	1,130	1,130	1,160	1,470	1,130	1,470	1,130	1,470	1,130	1,470
Annual Maintenance Cost (2022$)[4]	30	20	20	20	20	30	20	30	20	30	20	30

1. Product Class 7 is used for this analysis (Refrigerator-freezers—automatic defrost with side-mounted freezer with through-the-door ice service).
2. The volume shown here is the nominal total volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 32 ft^3 for all analysis years.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics, ice maker), not replaceable components (e.g., water filters).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect in September 2014.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (10.26, 1.28, 5.13).

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Residential Refrigerator-Freezers (Bottom)

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	19	19	19	19	19	19	19	19	19	19	19	19
Energy Consumption (kWh/y)[3]	547	473	521	473	469	430	469	430	469	430	469	430
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	1,190	920	920	920	920	930	920	930	920	930	920	930
Total Installed Cost (2022$)	1,190	920	920	920	920	930	920	930	920	930	920	930
Annual Maintenance Cost (2022$)[4]	30	20	20	20	20	20	20	20	20	20	20	20

1. Product Class 5 is used for this analysis (Refrigerator-freezers—automatic defrost with bottom-mounted freezer without through-the-door ice service).
2. The volume shown here is the nominal total volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 23 ft^3 for all analysis years.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics, ice maker), not replaceable components (e.g., water filters).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect in September 2014.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (10.26, 1.28, 5.13).

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Residential Refrigerator-Freezers

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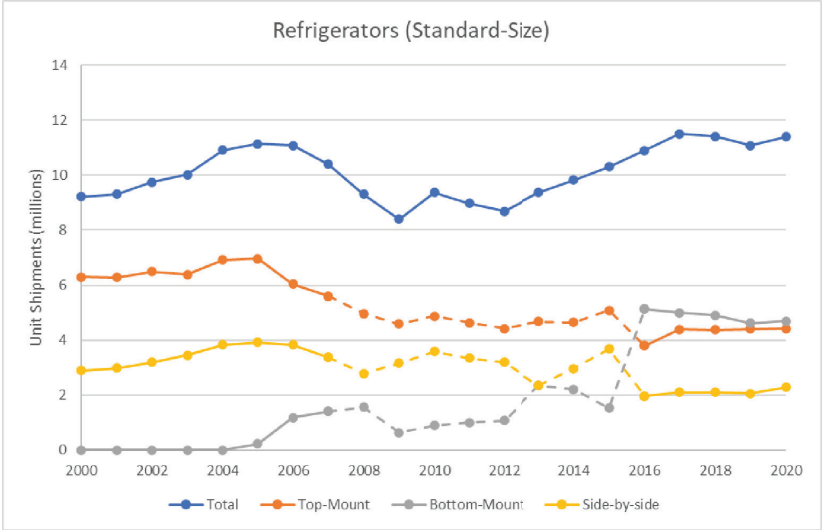
- Current Federal standards[1]:
  - Compliance required beginning September 15, 2014
  - Models divided into 32 product classes based on size (standard or compact), location of freezer (top, bottom, or side), type of defrost (automatic or manual), installation configuration (freestanding or built-in), and presence and configuration (through-the-door or inside cabinet) of automatic icemaker
  - Limits on annual electricity consumption expressed as functions of adjusted volume[2]
  - New product classes for built-in units
  - Amount by which standards are tightened varies by product class
- ENERGY STAR criteria limit annual electricity consumption to 10% less than the Federal standard
- Energy efficiency opportunities for refrigerators include:
  - More efficient compressor, including variable speed compressors
  - Brushless direct current (DC) fan motor (also known as ECM motor)
  - Variable defrost
  - Larger condenser
  - Dual evaporators
  - Vacuum-insulated panels
  - Refrigerants (Isobutane vs. R134a)
- Advanced Case: Increased market incentives will push product sales towards the ENERGY STAR level, but the technologies used to meet ENERGY STAR are already well-known and prices will likely not rise as manufacturing volumes increase at higher efficiencies.

[1]Energy Conservation Standards for Residential Refrigerators, Refrigerator-Freezers, and Freezers. 10 CFR 430.32(a).
[2]Adjusted Volume (AV) = (Fresh Volume) + 1.76 × (Freezer Volume)

Annual shipment volumes have rebounded from a sharp decline between 2006 and 2009, reaching approximately 11.4 million units in 2020.



Source: *Appliance Magazine; DOE's CCD, as of December 2017; ENERGY STAR Unit Shipment Data (2017-2020); Guidehouse analysis.* Dashed lines are a combination of interpolated and available data.

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Residential Refrigerator-Freezers

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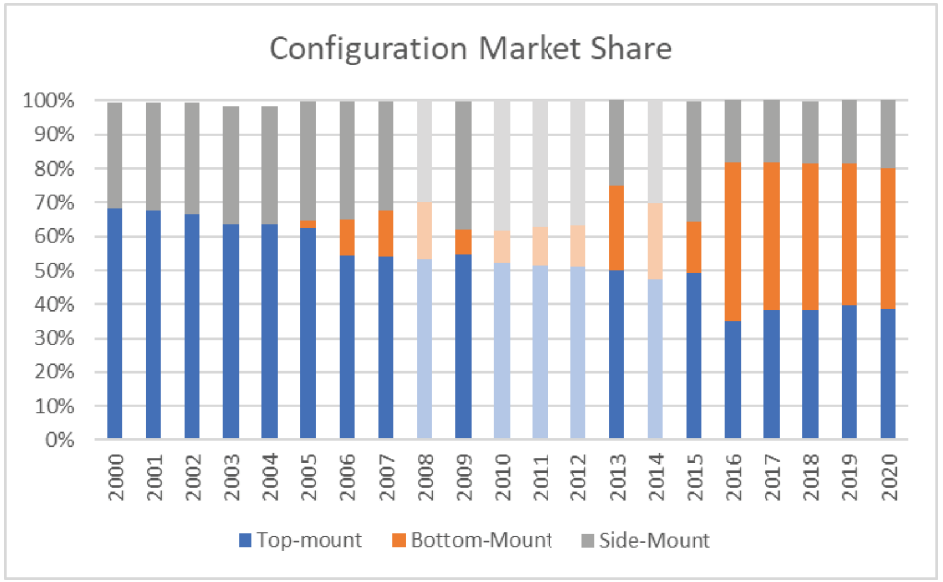
Bottom-mount units have gained market share, surpassing top-mount units since 2016.



Sources: *RF EERE 2021 Preliminary Analysis; DOE's CCD, as of December 2017; Guidehouse analysis.* Lightly shaded bars indicate interpolated data.

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Residential Freezers (Chest)

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Same as Reference Case

DATA[1]	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	16	15	15	15	15	15	15	15	15	15	15
Energy Consumption (kWh/y)[3]	360	297	297	297	287	297	287	297	287	297	287
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	510	590	680	680	690	680	690	680	690	680	690
Total Installed Cost (2022$)	510	590	680	680	690	680	690	680	690	680	690
Annual Maintenance Cost (2022$)[4]	10	10	10	10	10	10	10	10	10	10	10

1. Product Class 10 is used for this analysis (Chest freezers and all other freezers except compact freezers).
2. The volume shown here is the nominal volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume (zero for freezers) plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 26 ft^3, which is the average adjusted volume for units with a rounded total refrigerated volume of 15 ft^3 per the DOE CCD.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan, electronics)

Note:
Current standard went into effect in September 2014.
ENERGY STAR excluded as no products at the typical capacity are ENERGY STAR compliant.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (21.96, 1.83, 1).

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Residential Freezers (Upright)

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA[1]	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)[2]	17	17	18	18	18	18	18	18	18	18	18	18
Energy Consumption (kWh/y)[3]	615	446	497	493	448	441	448	441	448	441	448	441
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	690	880	830	830	830	830	830	830	830	830	830	830
Total Installed Cost (2022$)	690	880	830	830	830	830	830	830	830	830	830	830
Annual Maintenance Cost (2022$)[4]	10	10	10	10	10	10	10	10	10	10	10	10

1. Product Class 9 is used for this analysis (Upright freezers with automatic defrost).
2. The volume shown here is the nominal volume, not the adjusted volume, which is used to determine compliance with standards. The adjusted volume is equal to the fresh food internal volume (zero for freezers) plus the freezer internal volume times an adjustment factor, which depends on the product type.
3. Based on an adjusted volume of 31 ft^3, which is the average adjusted volume for units with a rounded total refrigerated volume of 18 ft^3 per the DOE CCD.
4. Maintenance costs include cost of repairing integral components (e.g., compressor, evaporator fan electronics).

Note:
Current standard went into effect in September 2014.
ENERGY STAR V. 5.1 went into effect September 2014.
Assume same lifetime as chest freezers.

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Residential Freezers

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- Current Federal standards[1]:
  - Compliance required beginning September 15, 2014
  - Models divided into 10 product classes based on size (standard or compact), orientation (chest or upright), type of defrost (automatic or manual), installation configuration (freestanding or built-in), and presence of automatic icemaker
    - Current analysis focuses on the two representative product classes analyzed in the recent rulemaking, chest and upright freezers.
  - Limits on annual electricity consumption expressed as functions of adjusted volume[2]
    - Chest freezers and all other freezers except compact freezers (PC 9): 9.88AV + 143.7
    - Upright freezers with automatic defrost (PC 10): 12.43AV + 326.1
- ENERGY STAR criteria limit annual electricity consumption to 10% less than the Federal standard
  - No ENERGY STAR compliant products at the typical capacity for chest freezers
- Energy efficiency opportunities for freezers include:
  - Higher efficiency and/or variable-speed compressor systems
  - Larger heat exchangers
  - Permanent-magnet fan motor systems (vs. shaded pole motor (SPM) and PSC fan motors)
  - Demand defrost systems
  - Vacuum-insulated panels
  - Thicker insulation (though at a loss of consumer utility)
  - Refrigerants (Isobutane vs. R134a)
  - Variable anti-sweat heating
  - Use of forced convection condenser (for upright freezers)
- Advanced Case: Increased market incentives will push product sales of upright freezers towards the ENERGY STAR level, but the technologies used to meet ENERGY STAR are already well-known and prices will likely not rise as manufacturing volumes increase at higher efficiencies. Unlikely to occur for chest freezers due to such a low existing market penetration of ENERGY STAR products.

[1]Energy Conservation Standards for Residential Refrigerators, Refrigerator-Freezers, and Freezers. 10 CFR 430.32(a).
[2]Adjusted Volume (AV) = (Fresh Volume) + 1.76 × (Freezer Volume).

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Residential Freezers

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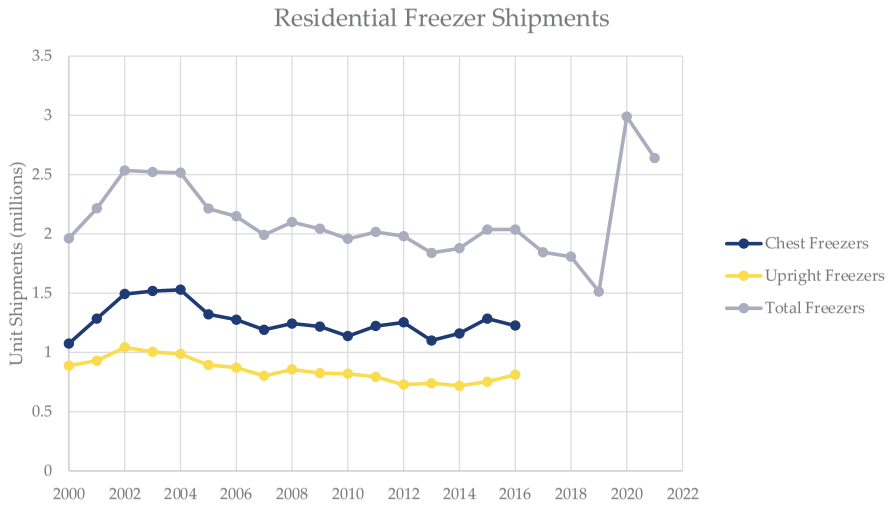
Shipment volumes held steady between 2007 to 2016 at about 2 million units per year. Shipments jumped to 3 million units in 2020. Chest freezers represent about 60% of the market.



Sources: *Appliance Magazine* from 2000 to 2016; *ENERGY STAR from 2017 to 2021*

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Residential Natural Gas Cooktops

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Same as Reference Case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	9	9	9	9	9	9	9	9	9	9
	23	23	23	23	23	23	23	23	23	23
Integrated Annual Energy Consumption (kBtu/y)[1]	1,061	914	914	730	914	730	914	730	914	730
Cooking Efficiency (%)	40	45	45	52	45	52	45	52	45	52
Average Life (y)	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	290	310	310	330	310	330	310	330	310	330
Total Installed Cost (2022$)[2]	420	460	460	480	460	480	460	480	460	480
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to Integrated Annual Energy Consumption (IAEC) (kBtu/h). The Consumer Cooking Products EERE 2020 notice of proposed determination (NOPD) used for 2020 and beyond in this analysis also determined IAEC using a different test procedure than the Consumer Cooking Products EERE 2016 SNOPR.
2. Equipment and installed costs are for cooktops only (not combined range units).
3. Annual maintenance costs are negligible.

Note:
The range for typical capacity represents the span of typical values.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (14.56, 5.73).

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Residential Natural Gas Ovens

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Same as Reference Case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	16	16	16	16	16	16	16	16	16	16
	18	18	18	18	18	18	18	18	18	18
Typical Cavity Volume (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kBtu/y)[1]	2,038	1,960	1,960	1,831	1,960	1,831	1,960	1,831	1,960	1,831
Cooking Efficiency (%)	6.6	6.9	6.9	7.3	6.9	7.3	6.9	7.3	6.9	7.3
Average Life (y)	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	740	770	770	810	770	810	770	810	770	810
Total Installed Cost (2022$)[2]	870	920	920	950	920	950	920	950	920	950
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to IAEC (kBtu/y). The 2015 IAEC value is reflective of freestanding standard gas ovens, which was previously determined to be the most representative product class. IAEC for 2020 and beyond is reflective of freestanding self-clean gas ovens, which is the product class that makes up the majority of historical and projected gas oven shipments.
2. Equipment and installed costs are for ovens only (not combined ranges). Costs are reflective of freestanding self-clean oven units with single oven component, which represent the majority of the market.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (14.56, 5.73).

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Residential Natural Gas Ranges

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Same as Reference Case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity of Cooktop Component (kBtu/h)	9	9	9	9	9	9	9	9	9	9
	23	23	23	23	23	23	23	23	23	23
Typical Capacity of Oven Component (kBtu/h)	16	16	16	16	16	16	16	16	16	16
	18	18	18	18	18	18	18	18	18	18
Typical Cavity Volume of Oven Component (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kBtu/y)[1]	3,099	2,874	2,874	2,561	2,874	2,561	2,874	2,561	2,874	2,561
Average Life (y)	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$) [2]	750	770	770	850	770	850	770	850	770	850
Total Installed Cost (2022$) [2]	900	920	920	1,000	920	1,000	920	1,000	920	1,000
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. IAEC of a natural gas range is calculated as the sum of the IAEC for a natural gas cooktop and natural gas oven. IAEC of the oven component is reflective of freestanding self-clean gas ovens, which represent the majority of the market. The 2015 IAEC value of the oven component is reflective of freestanding standard gas ovens, which was previously determined to be the most representative product class.
2. Retail and installed cost are reflective of a typical unit with standard 30-inch width and 4 to 5 cooking top heating elements. Based on data from DOE rulemakings, Gordian's RSMeans Data – Building Construction Costs 2023, and distributors, total installed cost is estimated to be around $150 more than retail equipment cost.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (14.56, 5.73).

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Residential Natural Gas Cooktops, Ovens, and Ranges

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- DOE analyzes cooktops and ovens separately, although they are often sold together in a single unit that combines both a cooktop and an oven into a product referred to as a range.
- Since January 1, 1990, gas cooking products with an electrical supply cord have been required to not be equipped with a constant burning pilot light. This requirement extended to gas cooking products without an electrical supply cord, as of April 9, 2012.
- DOE published a final rule in 2009[1] in which it determined that no standard for cooking efficiency would be cost-justified.
- DOE initiated a standards rulemaking in 2014 to consider amended standards for cooking products, including gas cooktops and ovens[2].
- On September 2, 2016, DOE proposed performance-based standards for gas cooktops and ovens that would take effect in 2020, if adopted.
- DOE established the new IAEC metric, in kBtu/y, to replace cooking efficiency (%).
- On December 14, 2020, DOE initially determined that amended energy conservation standards for consumer conventional cooking products would not be economically justified and would not result in significant conservation of energy[3].
- On February 2, 2023, DOE proposed new and amended energy conservation standards for consumer conventional cooking products[4].
- The IAEC of a range is calculated as the sum of the IAECs for cooktops and ovens. However, retail and installation costs for a range are similar to the cost of an oven.

[1]Energy Conservation Standards for Certain Consumer Products (Dishwashers, Dehumidifiers, Microwave Ovens, and Electric and Gas Kitchen Ranges and Ovens) and for Certain Commercial and Industrial Equipment (Commercial Clothes Washers); Final Rule. 74 FR 16040.
[2]Energy Conservation Standards for Residential Conventional Cooking Products; Supplemental notice of proposed rulemaking (SNOPR). 81 FR 60784.
[3]Energy Conservation Standards for Consumer Conventional Cooking Products; Notice of proposed determination (NOPD). 85 FR 80982.
[4]Energy Conservation Standards for Consumer Conventional Cooking Products; SNOPR. 88 FR 6818.

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Residential Natural Gas Cooktops, Ovens, and Ranges

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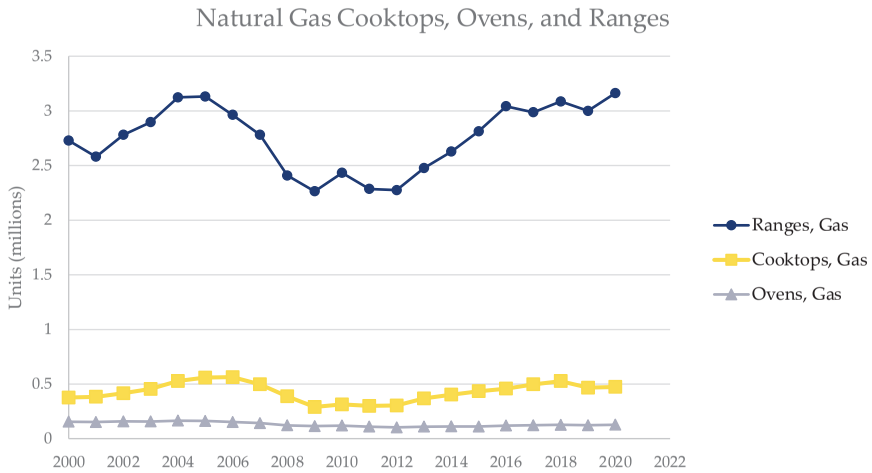
Shipments have been rising since 2012. In 2020, gas range shipments surpassed the peak reached in 2005.



Source: *Appliance Magazine and Consumer Cooking Products EERE 2022 SNOPR*

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Residential Electric Cooktops

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Same as Reference Case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (W)	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700
Integrated Annual Energy Consumption (kWh/y)[1]	155	155	155	119	155	119	155	119	155	119
Average Life (y)	17	17	17	17	17	17	17	17	17	17
Retail Equipment Cost (2022$)[2]	470	470	470	810	470	810	470	810	470	810
Total Installed Cost (2022$)[2]	620	620	620	1,230	620	1,230	620	1,230	620	1,230
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to IAEC (kBtu/y). IAEC was determined using DOE rulemaking data for the most representative product class, electric smooth element cooking tops, which covers cooking tops with electric resistance heating elements and cooking tops with induction heating elements.
2. Equipment and installed costs are for cooktops only (not combined range units). Costs were determined using DOE rulemaking data for the most representative product class, electric smooth cooking tops, which includes cooking tops with electric resistance heating elements and cooking tops with induction heating elements. A high-end unit with induction technology is expected to have a greater retail equipment cost and greater installation cost in order to implement this technology.
3. Maintenance costs are negligible.

Note:
The range for typical capacity represents the span of typical values.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (16.88, 6.99).

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Residential Electric Ovens

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Same as Reference Case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (W)	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400
Typical Cavity Volume (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kWh/y)[1]	355	355	355	278	355	278	355	278	355	278
Average Life (y)	17	17	17	17	17	17	17	17	17	17
Retail Equipment Cost (2022$)[2]	630	630	630	730	630	730	630	730	630	730
Total Installed Cost (2022$)[2]	770	770	770	870	770	870	770	870	770	870
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. Although there is no performance standard in effect, the test procedure metric has changed from Cooking Efficiency (%) to IAEC (kBtu/y). IAEC was determined using DOE rulemaking data for freestanding electric self-clean ovens, which represent the majority of the market.
2. Equipment and installed costs are for ovens only (not combined ranges). Costs are reflective of freestanding self-clean oven units with single oven component, which represent the majority of the market.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (16.88, 6.99).

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Residential Electric Ranges

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Same as Reference Case

DATA	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity of Cooktop Component (W)	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700	3,700
Typical Capacity of Oven Component (W)	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400
Typical Cavity Volume of Oven Component (ft^3)	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Integrated Annual Energy Consumption (kWh/y)[1]	510	510	510	397	510	397	510	397	510	397
Average Life (y)	17	17	17	17	17	17	17	17	17	17
Retail Equipment Cost (2022$) [2]	630	630	630	900	630	900	630	900	630	900
Total Installed Cost (2022$) [2]	770	770	770	1,050	770	1,050	770	1,050	770	1,050
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-

1. IAEC of an electric range is calculated as the sum of the IAEC for an electric cooktop and an electric oven. IAEC of the electric cooktop component was determined using DOE rulemaking data for the most representative product class, electric smooth element cooking tops, which covers cooking tops with electric resistance heating elements and cooking tops with induction heating elements. IAEC of the electric oven component was determined using DOE rulemaking data for freestanding electric self-clean ovens, which represent the majority of the market.
2. Retail and installed cost are reflective of standard units that are 30-inch wide and have 4 to 5 cooking top heating elements. Based on data from DOE rulemakings, Gordian's RSMeans Data – Building Construction Costs 2023, and distributors, total installed cost is estimated to be around $140 more than retail equipment cost for a typical unit, and $150 more than retail equipment cost for a high-end unit. A high-end unit with an induction cooking top component is expected to have a greater retail equipment cost and greater installation cost in order to implement this technology.
3. Maintenance costs are negligible.

Note:
Ranges represent the span of typical values for a given parameter.
Average life is determined using a Weibull distribution characterized by the following scale (α) and shape (β) parameters: (16.88, 6.99).

Residential Electric Cooktops, Ovens, and Ranges

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- DOE analyzes cooktops and ovens separately, although they are often sold together in a single unit that combines both a cooktop and an oven into a product referred to as a range.
- DOE initiated a standards rulemaking in 2014 to consider amended standards for cooking products, including electric cooktops and ovens[1].
- On September 2, 2016, DOE proposed performance-based standards for electric cooktops and ovens that would take effect in 2020 if adopted.
- DOE established the new IAEC metric, in kWh/y, to replace cooking efficiency (%).
- On December 14, 2020, DOE initially determined that amended energy conservation standards for consumer conventional cooking products would not be economically justified and would not result in a significant conservation of energy[2].
- On February 2, 2023, DOE proposed new and amended energy conservation standards for consumer conventional cooking products[3].
- The IAEC of a range is calculated as the sum of the IAECs for cooktops and ovens. However, retail and installation costs for a range are similar to the cost of an oven.

[1]Energy Conservation Standards for Residential Conventional Cooking Products; Supplemental notice of proposed rulemaking (SNOPR). 81 FR 60784.
[2]Energy Conservation Standards for Consumer Conventional Cooking Products; Notice of proposed determination (NOPD). 85 FR 80982.
[3]Energy Conservation Standards for Consumer Conventional Cooking Products; SNOPR. 88 FR 6818.

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Residential Electric Cooktops, Ovens, and Ranges

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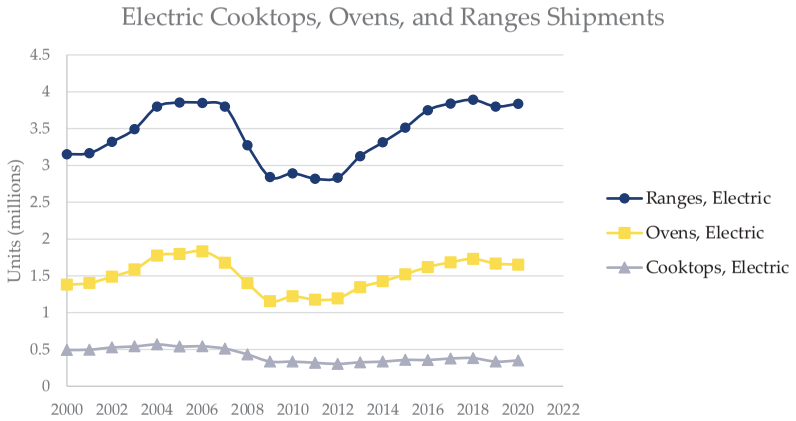
Shipments of electric cooking products reached a peak in 2006. Shipments of ranges and ovens have been rising again since 2012. In 2018, electric range shipments surpassed the peak reached in 2006.



Source: *Consumer Cooking Products EERE 2022 SNOPR*

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Residential Clothes Dryers (Electric)

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Higher typical efficiency product with the same costs as ref. case despite increased efficiency.

DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1[1]	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	7.4	7.4	7.4	7.4	7.4	4.5	7.4	4.5	7.4	4.5	7.4	4.5
Combined Energy Factor, D1 (lb/kWh)[2]	3.59	3.73	3.73	3.73	NA	3.93	3.73	3.93	3.73	3.93	3.73	3.93
Combined Energy Factor, D2 (lb/kWh)[2]	3.59	3.93	3.73	3.93	3.93	11.00	5.34	11.00	6.48	11.00	7.38	11.00
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8	8
	18	18	18	18	18	18	18	18	18	18	18	18
Retail Equipment Cost (2022$)	580	580	580	580	580	980	580	980	580	980	580	980
Total Installed Cost (2022$)	710	710	710	710	710	1,110	710	1,110	710	1,110	710	1,110
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-	-	-

1. ENERGY STAR V. 1.1 applies to vented and ventless standard electric clothes dryers.
2. The efficiency metric changed from EF to combined energy factor (CEF) in 2015. The 2015 Installed Base CEF data accounts for units tested to appendix D1 and appendix D2, because data specific to each appendix is not available for that year.
3. Maintenance costs are negligible. DOE estimated that on average 2.7 percent of electric and 3.3 percent of gas residential clothes dryers are repaired each year. (EERE 2014)

Note:
DOE test procedures for consumer clothes dryers appear at title 10 of the Code of Federal Regulations part 430, subpart B, appendix D1 and appendix D2. The second test method, appendix D2, was finalized in a final rule published by DOE on August 14, 2013. For current standard testing, units must be tested according to either the appendix D1 or the appendix D2 test method. ENERGY STAR V. 1.1 requires certified units to be tested according to the appendix D2 test method. The appendix D1 and appendix D2 test methods determine CEF differently.
The current standard went into effect in January 2015.
ENERGY STAR V. 1.1 went into effect in May 2017.
The range for average life represents the span of typical values.

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Residential Clothes Dryers (Gas)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1[1]	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Combined Energy Factor, D1 (lb/kWh)[2]	3.18	3.30	3.30	3.30	NA	3.48	3.30	3.48	3.30	3.48	3.30	3.48
Combined Energy Factor, D2 (lb/kWh)[2]	3.18	3.48	3.30	3.48	3.48	3.50	3.48	3.50	3.48	3.50	3.48	3.50
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8	8
	18	18	18	18	18	18	18	18	18	18	18	18
Retail Equipment Cost (2022$)	660	670	660	670	670	670	670	670	670	670	670	670
Total Installed Cost (2022$)	860	870	870	870	870	870	870	870	870	870	870	870
Annual Maintenance Cost (2022$)[3]	-	-	-	-	-	-	-	-	-	-	-	-

1. ENERGY STAR V. 1.1 applies to vented and ventless standard electric clothes dryers.
2. The efficiency metric changed from EF to CEF in 2015. The 2015 Installed Base CEF data accounts for units tested to appendix D1 and appendix D2, because data specific to each appendix is not available for that year.
3. Maintenance costs are negligible. DOE estimated that on average 2.7 percent of electric and 3.3 percent of gas residential clothes dryers are repaired each year. (EERE 2014)

Note:
DOE test procedures for consumer clothes dryers appear at title 10 of the Code of Federal Regulations part 430, subpart B, appendix D1 and appendix D2. The second test method, appendix D2, was finalized in a final rule published by DOE on August 14, 2013. For current standard testing, units must be tested according to either the appendix D1 or the appendix D2 test method. ENERGY STAR V. 1.1 requires certified units to be tested according to the appendix D2 test method. The appendix D1 and appendix D2 test methods determine CEF differently.
The current standard went into effect in January 2015.
ENERGY STAR V. 1.1 went into effect in May 2017.
The range for average life represents the span of typical values.

Residential Clothes Dryers

- Current standards[1] in effect since 2015:
  - For standard-size electric units : CEF ≥ 3.73 pound per kilowatt hours (lb/kWh)
  - For gas units: CEF ≥ 2.30 lb/kWh
  - Units may be tested according to the test method in appendix D1 or appendix D2, which was finalized in 2013.
- The main differences between appendix D1 and appendix D2 are:
  - Appendix D2 includes test methods that more accurately measure the effects of automatic cycle termination and that may result in differences in the total measured energy consumption of the test cycle as compared to the test methods in appendix D1.
  - Appendix D2 contains instructions for the testing of timer dryers, which include a lower final moisture content (FMC) of the test load as compared to the version of appendix D1 used for the 2011 rulemaking analysis.
- Efficiency improvement technologies for clothes dryers include:
  - Multi-step or modulating heat
  - Higher efficiency drum motors
  - Inlet air pre-heat
  - Better control systems for cycle termination
  - Heat pump (for electric clothes dryers)
- EPA developed ENERGY STAR V. 1.1, which became effective in 2017 and requires units to be tested according to the test method in appendix D2.
- Standard-size heat pump clothes dryers with CEF values up to 11.0 are currently available in the U.S. market. High initial cost has limited market penetration, but some utilities are offering rebates to support market penetration.
- Advanced Case: Due to increases in market incentives, the residential electric clothes dryers market will see an increase in adoption of heat pump dryers that improve the typical efficiency products.

[1]Energy Conservation Standards for Consumer Clothes Dryers. 10 CFR 430.32(h).

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Residential Clothes Dryers

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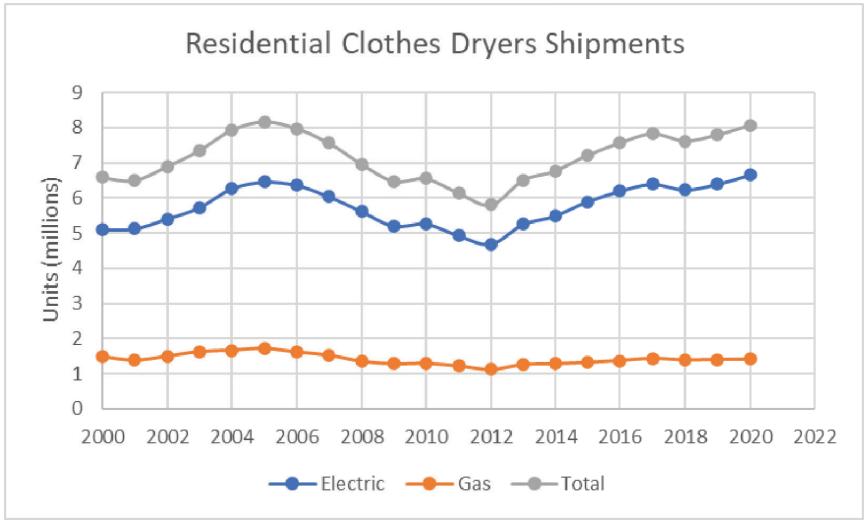
Shipment volumes have been on the rise since 2012. Gas dryers continue to account for about one-fifth of the market.



Source: *Consumer Clothes Dryers EERE 2022 NOPR*

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Residential Clothes Washers (Front)

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DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	3.7	4.1	3.4	4.5	4.5	5.0	4.5	5.0	4.5	5.0	4.5	5.0
Integrated Modified Energy Factor (ft^3/kWh/cycle)[1]	2.16	2.76	1.84	2.76	2.76	3.10	2.76	3.10	2.76	3.10	2.76	3.10
Integrated Water Factor (gal/cycle/ft^3)[2]	4.7	3.2	4.7	3.2	3.2	2.7	3.2	2.7	3.2	2.7	3.2	2.7
Average Life (y)	6	6	6	6	6	6	6	6	6	6	6	6
	17	17	17	17	17	17	17	17	17	17	17	17
Water Consumption (gal/cycle)	17	14	16	14	14	14	14	14	14	14	14	14
Hot Water Energy (kWh/cycle)	0.21	0.17	0.36	0.12	0.12	0.13	0.12	0.13	0.12	0.13	0.12	0.13
Machine Energy (kWh/cycle)	0.17	0.14	0.15	0.12	0.12	0.17	0.12	0.17	0.12	0.17	0.12	0.17
Dryer Energy (kWh/cycle)	1.31	1.24	1.34	1.17	1.17	1.56	1.17	1.56	1.17	1.56	1.17	1.56
Retail Equipment Cost (2022$)	735	1,000	705	930	930	950	930	950	930	950	930	950
Total Installed Cost (2022$)	915	1,175	880	1,130	1,130	1,150	1,130	1,150	1,130	1,150	1,130	1,150
Annual Maintenance Cost (2022$)	15	15	15	15	15	15	15	15	15	15	15	15

1. The efficiency metric changed from Modified Energy Factor to Integrated Modified Energy Factor (IMEF) in 2015.
2. The efficiency metric changed from Water Factor to Integrated Water Factor (IWF) in 2015.

Note:
The current standard went into effect in January 2018.
ENERGY STAR V. 8.1 went into effect in February 2018.
The range for average life represents the span of typical values.

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Residential Clothes Washers (Top)

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Same as Reference Case

DATA	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	3.3	3.4	3.5	3.5	4.4	5.5	3.5	5.5	3.5	5.5	3.5	5.5
Integrated Modified Energy Factor (ft^3/kWh/cycle)[1]	1.14	1.57	1.57	1.57	2.06	2.76	1.57	2.76	1.57	2.76	1.57	2.76
Integrated Water Factor (gal/cycle/ft^3)[2]	9.2	6.5	6.5	6.5	4.3	3.2	6.5	3.2	6.5	3.2	6.5	3.2
Average Life (y)	6	6	6	6	6	6	6	6	6	6	6	6
	17	17	17	17	17	17	17	17	17	17	17	17
Water Consumption (gal/cycle)	30	22	23	23	19	18	23	18	23	18	23	18
Hot Water Energy (kWh/cycle)	0.90	0.39	0.41	0.41	0.38	0.24	0.41	0.24	0.41	0.24	0.41	0.24
Machine Energy (kWh/cycle)	0.25	0.13	0.14	0.14	0.12	0.13	0.14	0.13	0.14	0.13	0.14	0.13
Dryer Energy (kWh/cycle)	1.73	1.63	1.68	1.68	1.64	1.61	1.68	1.61	1.68	1.61	1.68	1.61
Retail Equipment Cost (2022$)	590	590	520	520	640	725	520	725	520	725	520	725
Total Installed Cost (2022$)	765	765	715	715	840	920	715	920	715	920	715	920
Annual Maintenance Cost (2022$)	15	15	15	15	15	15	15	15	15	15	15	15

1. The efficiency metric changed from Modified Energy Factor to IMEF in 2015.
2. The efficiency metric changed from Water Factor to IWF in 2015.

Note:
The current standard went into effect in January 2018.
ENERGY STAR V. 8.1 went into effect in February 2018.
The range for average life represents the span of typical values.

Residential Clothes Washers

- The analysis treats front- and top-loading models separately due to their different energy use characteristics.
- Federal standards[1] for standard-capacity clothes washers (≥ 1.6 ft^3):

	Integrated Modified Energy Factor		Integrated Water Factor	
	Top-Loading	Front-Loading	Top-Loading	Front-Loading
Current DOE Standard (effective 1/1/2018)	≥ 1.57	≥ 1.84	≤ 6.5	≤ 4.7
Current ENERGY STAR V. 8.1 (effective 4/22/2021)	≥ 2.06	≥ 2.76	≤ 4.3	≤ 3.2

- In 2020, about 40% of top-loading models and almost all front-loading models achieved the ENERGY STAR level.
- Energy efficiency improvement technologies for clothes washers include:
  - Higher efficiency motors and higher spin speeds
  - Better load sensing for adaptive water fill control
  - Reduced water temperature and quantity, while providing equivalent cleaning and rinsing performance
- Maintenance costs include replacement or repair of the drain pump, control board, motor, rubber gaskets, or control panel knobs.
- The products on the market with the highest IMEF have significantly larger capacity and therefore use more energy per cycle than typical, smaller capacity products but still perform more efficiently on a per volume basis.

[1]Energy Conservation Standards for Consumer Clothes Washers. 10 CFR 430.32(g).

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Residential Clothes Washers

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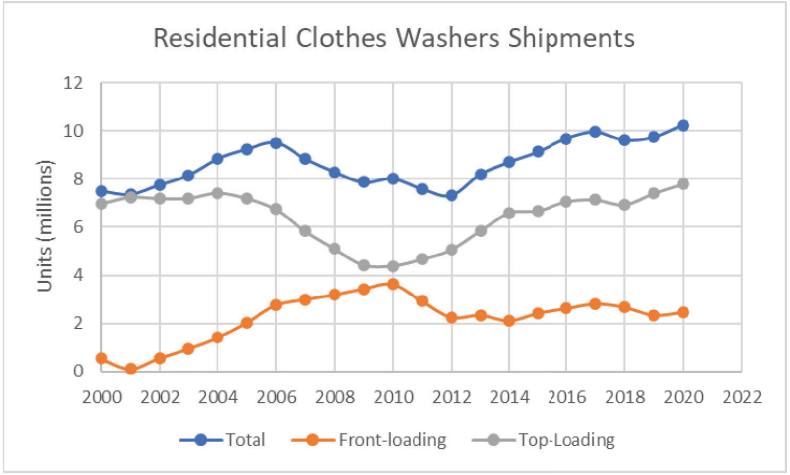
Shipments have been on the rise since 2012 and reached a peak of about 10 million in 2020. Since 2012, top-loading and front-loading units represent approximately 75% and 25% of shipments, respectively.



Source: *AHAM Shipment Data; RCW EERE 2021 Preliminary Analysis*

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Residential Dishwashers

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Same as Reference Case

DATA	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 6.0	High	ENERGY STAR V. 7.0	Typical	High	Typical	High	Typical	High
Typical Annual Energy Use (kWh/y)	295	270	307	270	270	225	240	240	225	240	225	240	225
Water Consumption (gal/cycle)	4.25	3.50	5.00	3.50	3.50	2.40	3.20	3.20	2.40	3.20	2.40	3.20	2.40
Water Heating Energy Use (kWh/y)[1]	154	125	176	123	123	84	112	123	84	123	84	123	84
Average Life (y)	15	15	15	15	15	15	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)	440	380	310	340	340	500	430	340	500	340	500	340	500
Total Installed Cost (2022$)	840	570	490	520	520	690	610	520	690	520	690	520	690
Annual Maintenance Cost (2022$)[2]	-	-	-	-	-	-		-	-	-	-	-	-

1. Refers to that portion of "Typical Annual Energy Use" that is the energy used to heat water in a separate water heater before it enters the dishwasher. The energy used to heat water inside the dishwasher cannot be disaggregated from the total.
2. Maintenance costs are negligible.

Note:
All values in table reflect 215 cycles/year according to the current test procedure at 10 CFR 430 Appendix C1.
The current standard went into effect in May 2013.
ENERGY STAR V. 6.0 went into effect in January 2016.
ENERGY STAR V. 7.0 will go into effect in July 2023.
Average life is determined using a Weibull distribution characterized by the following scale (α), shape (β), and delay (θ) parameters: (15.9, 1.8, 1).

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Residential Dishwashers

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- Performance criteria for standard-capacity dishwashers (assumes 215 cycles/year):
  - Federal Standards:
    - May 30, 2013: ≤ 307 kWh/y, ≤ 5.0 gal/cycle (DOE Direct Final Rule, published May 2012)
  - ENERGY STAR Criteria:
    - Jan. 29, 2016: ≤ 270 kWh/y (5% allowance for connected), ≤ 3.5 gal/cycle (V. 6.0)
    - July 19, 2023: ≤ 240 kWh/y, ≤ 3.2 gal/cycle (V. 7.0, effective August 2023)
- ENERGY STAR has maintained a very high market share for several years (93% in 2021), so sales-weighted average efficiency has tracked ENERGY STAR levels.
  - Due to the historically high market penetration of ENERGY STAR products, it is expected that manufacturers will make the necessary adjustments so ENERGY STAR V. 7.0 levels will be typical in future projections.
- Test procedures:
  - Accounts for motor, dryer, booster heater (if present), and hot water from separate water heater, as well as standby and off-mode energy.
  - ENERGY STAR established a cleaning performance test method. While cleaning performance reporting is currently optional, V. 7.0 requires a cleaning index of 65 or higher for ENERGY STAR certification.
  - In January 2023, DOE established a test procedure at Appendix C2, which would go into effect at the time of any amended energy conservation standards. Appendix C2 establishes a minimum cleaning index threshold of 70 as a condition for a valid test cycle. The cleaning index threshold of 70 established by DOE is equivalent to the cleaning index threshold of 65 specified in ENERGY STAR V. 7.0.
- Efficiency improvement technologies for dishwashers include:
  - Better soil sensing
  - Control strategies
  - Water distribution (small pipes, fine filter, small sump, multiple spray arms, alternating water use) and controls (flow meter, temperature sensor)
  - Inline water heater (to minimize sump volume)
  - Separate drain pump, high-efficiency, variable-speed circulation pump motor
  - Condensation drying (rather than power dry)

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Residential Dishwashers

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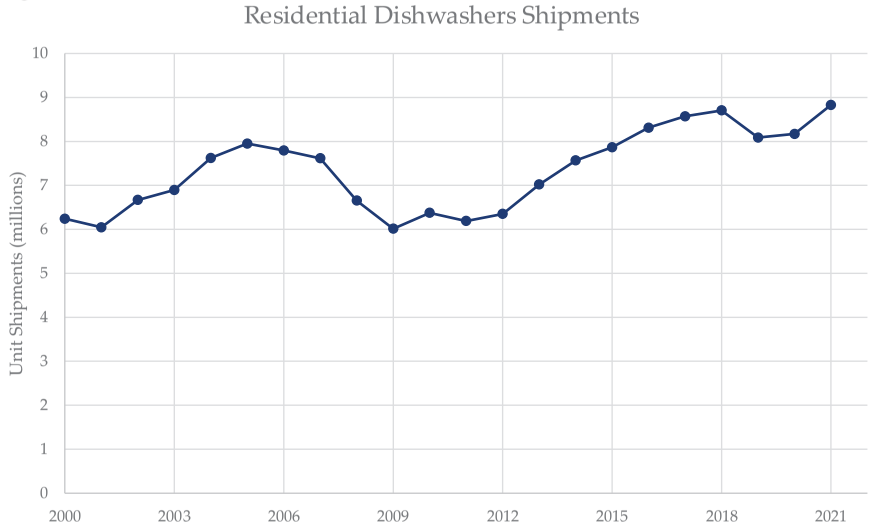
Shipments increased steadily from the early 1990s until the 2008-2009 recession. Shipments have resumed similar growth since then.



Source: *DW EERE 2022 Preliminary Analysis*

Commercial Space Heating and Cooling

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Commercial Gas-Fired Furnaces

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High thermal efficiency increase is possible with increased costs.

DATA	2012	2018	2022			2023[1]		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	Typical	Typical	Typical
Typical Input Capacity (kBtu/h)[2]	400	400	250	250	250	250	250	250	250	250
Thermal Efficiency (%)[3]	80	80	80	81	81	81	81	95	81	95
Typical Output Capacity (kBtu/h)	320	320	200	203	203	203	203	238	203	238
Average Life (y)	23	23	23	23	23	23	23	23	23	23
Retail Equipment Cost (2022$)	1,230	1,230	1,230	1,260	1,260	1,260	1,260	3,340	1,260	3,340
Total Installed Cost (2022$)	2,540	2,540	2,540	2,580	2,580	2,580	2,580	5,230	2,580	5,230
Total Installed Cost (2022$/kBtu/h)	6	6	10	10	10	10	10	21	10	21
Annual Maintenance Cost (2022$)	200	200	200	200	200	200	200	210	200	210
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1	1	1	1

1. In 2023, the new Energy Conservation Standards for Commercial Warm Air Furnaces (CWAF) took effect. These projections reflect the 2023 minimum thermal efficiency requirement for gas-fired furnaces, 81%.
2. When this analysis was previously conducted in EIA Technology Forecast Updates (2018), a typical input capacity of 400 kBtu/h was listed. An updated typical input capacity value of 250 kBtu/h was determined through an evaluation of the units in the DOE CCD as of August 2022. CWAF EERE 2015 also listed a representative input capacity of 250 kBtu/h.
3. DOE's efficiency metric for commercial furnaces accounts only for flue losses, not jacket losses.

Note:
The previous standard went into effect in January 1994. The current standard went into effect in January 2023.

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Commercial Gas-Fired Furnaces

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- Until 2022, the Federal standard required minimum 80% thermal efficiency. This metric, more commonly called "combustion efficiency" in other contexts, accounts only for flue losses, not jacket losses.
  - The Federal standard applied to all units manufactured on or after January 1, 1994, with maximum rated heat input ≥ 225,000 Btu per hour.
  - On January 1, 2023, the minimum Federal standard increased to 81% thermal efficiency.
- ASHRAE Standard 90.1, which is used as a commercial building code in many states, stipulates that furnaces that are not within the conditioned space shall not have jacket losses exceeding 0.75% of the input rating.
- Commercial furnaces are typically non-condensing with thermal efficiencies ranging from 80% to 81%. Condensing commercial furnaces, which can achieve up to 95% thermal efficiency, were previously introduced to the market but are not currently available due to cost and reliability concerns. The highest thermal efficiency included in DOE's CCD at this time is 81%.
- Besides capacity, commercial units can differ from residential furnaces in terms of the control system (i.e., integration with a Building Management System, twinning, or other staging strategies). Commercial systems may also use a heat recovery system to pre-heat inlet air.
- Advanced Case: Increased high efficiencies are feasible due to market incentives to re-introduce condensing commercial gas-fired furnaces through additional investment, research, and development. No significant changes otherwise.

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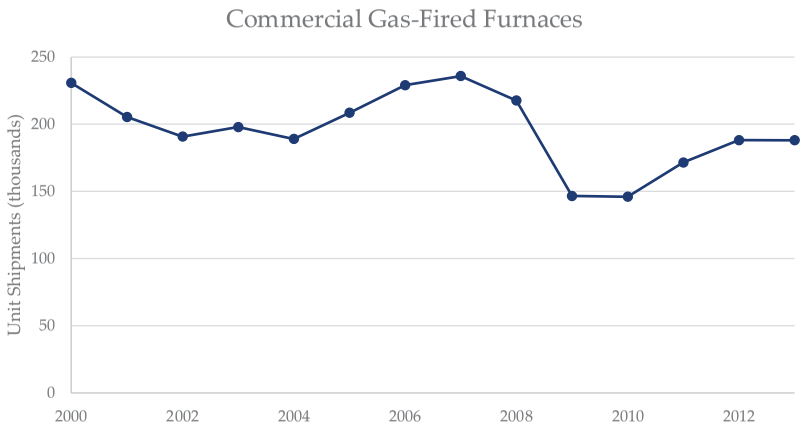
Annual shipments reached a peak of 235.9 thousand units in 2007. Following a decline in shipments after 2007, shipments increased to 188.1 thousand units in 2013. Shipment data after 2013 is not available.



Source: *AHRI*

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Same as Reference Case

DATA	2012	2018	2022			2023[1]	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	400	400	250	250	250	250	250	250	250	250	250	250
Thermal Efficiency (%)[2]	81	82	81	82	85	82	82	85	82	85	82	85
Typical Output Capacity (kBtu/h)	324	328	203	205	213	205	205	213	205	213	205	213
Average Life (y)	23	23	23	23	23	23	23	23	23	23	23	23
Retail Equipment Cost (2022$)	5,500	5,560	5,500	5,560	6,020	5,560	5,560	6,020	5,560	6,020	5,560	6,020
Total Installed Cost (2022$)	7,740	7,810	7,740	7,810	8,380	7,810	7,810	8,380	7,810	8,380	7,810	8,380
Total Installed Cost (2022$/kBtu/h)	24	24	38	38	39	38	38	39	38	39	38	39
Annual Maintenance Cost (2022$)	360	360	360	360	370	360	360	370	360	370	360	370
Annual Maintenance Cost (2022$/kBtu/h)	1	1	2	2	2	2	2	2	2	2	2	2

1. In 2023, the new Energy Conservation Standards for CWAF took effect. These projections reflect the 2023 minimum thermal efficiency requirement for oil-fired furnaces, 82%.
2. DOE's efficiency metric for commercial furnaces accounts only for flue losses, not jacket losses.

Note:
The previous standard went into effect in January 1994. The current standard went into effect in January 2023.

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- Until 2022, the Federal standard required minimum 81% thermal efficiency. This metric, more commonly called "combustion efficiency" in other contexts, accounts only for flue losses, not jacket losses.
  - The Federal standard applied to all units manufactured on or after January 1, 1994, with maximum rated heat input ≥ 225,000 Btu per hour.
  - On January 1, 2023, the minimum Federal standard increased to 82% thermal efficiency.
- ASHRAE Standard 90.1, which is used as a commercial building code in many states, stipulates that furnaces that are not within the conditioned space shall not have jacket losses exceeding 0.75% of the input rating.
- Commercial oil-fired furnaces have thermal efficiencies ranging from 81% to 85% and are non-condensing (i.e., not designed for condensation of flue gases).
- Besides capacity, commercial units can differ in terms of the control system (i.e., integration with a Building Management System, twinning, or other staging strategies). Commercial systems may also use a heat recovery system to pre-heat inlet air.
- The maintenance cost estimate assumes two cleanings per year.

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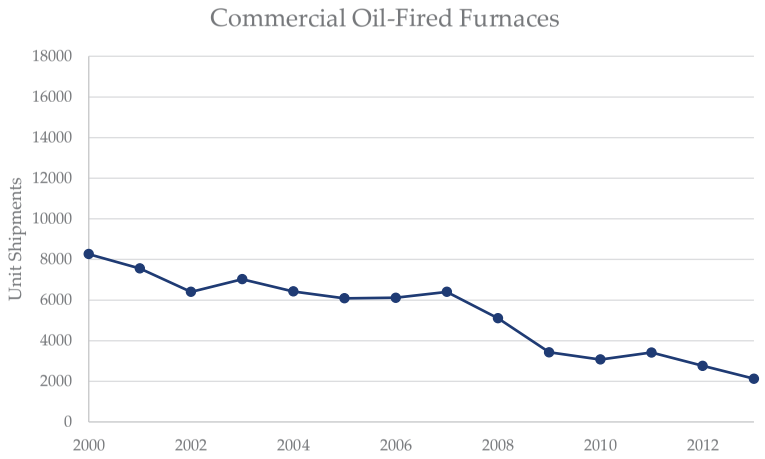
Annual shipments for commercial oil-fired furnaces have steadily decreased over time to 2,127 units in 2013. Shipment data after 2013 is not available.



Source: *AHRI*

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Commercial Electric Resistance Heaters

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Same as Reference Case

DATA	2012		2018		2022		2030		2040		2050	
	Installed Base: Small	Installed Base: Large	Installed Base: Small	Installed Base: Large	Small	Large	Small	Large	Small	Large	Small	Large
Typical Capacity (kBtu/h)[1]	17	170	17	170	17	170	17	170	17	170	17	170
Efficiency (%)	100	100	100	100	100	100	100	100	100	100	100	100
Average Life (y)	18	18	18	18	18	18	18	18	18	18	18	18
Retail Equipment Cost (2022$)	1,000	6,320	1,000	6,320	500	4,630	500	4,630	500	4,630	500	4,630
Total Installed Cost (2022$)	1,240	7,470	1,240	7,470	660	5,470	660	5,470	660	5,470	660	5,470
Total Installed Cost (2022$/kBtu/h)	73	44	73	44	39	32	39	32	39	32	39	32
Annual Maintenance Cost (2022$)[2]	-	-	-	-	-	-	-	-	-	-	-	-
Annual Maintenance Cost (2022$/kBtu/h)	-	-	-	-	-	-	-	-	-	-	-	-

1. Capacity is output.
2. Annual Maintenance Cost is negligible.

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- This analysis examined standard suspended electric wall and ceiling unit heaters, which are more common in commercial settings than baseboard electric heaters that were considered for the residential analysis.
- Electric unit heaters range in capacity from 2 to 100 kW (7 to 340 kBtu/h), with 5 to 50 kW (17 to 170 kBtu/h) being the most typical units on the market.
- Electric resistance heaters are considered near 100% efficient because there is no heat loss through ducts or combustion.
- Installation time and costs are estimated to be minimal.

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Commercial Electric Boilers

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Same as Reference Case

DATA	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (kW)[1]	165	165	165	165	165	165
Efficiency (%)	98	98	98	98	98	98
Average Life (y)	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	11,620	11,590	9,790	9,790	9,790	9,790
Total Installed Cost (2022$)[2]	17,500	13,820	11,950	11,950	11,950	11,950
Total Installed Cost (2022$/kBtu/h)	31	25	21	21	21	21
Annual Maintenance Cost (2022$)[2]	170	130	130	130	130	130
Annual Maintenance Cost (2022$/kBtu/h)	-	-	-	-	-	-

1. Capacity is output.
2. Retail and installed costs for 2022 and forecasts for 2030 and beyond are based on Gordian's RSMeans Data – Building Construction Costs 2023. Maintenance costs are same as EIA Technology Forecast Updates (2018), updated to reflect 2022$. The costs shown are for one 165kW unit, which would equate to a steady load of approximately 550,000 Btu/h. Annual maintenance in a typical application would include draining the unit for removal of any accumulated scale or sludge buildup.

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Commercial Electric Boilers

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- There are currently no federal standards associated with electric boilers.
- The costs shown are for one 165kW unit, which would equate to a steady load of approximately 550,000 Btu/h.
- Service life is determined mainly by water quality. Water conditioning (e.g., filters, softeners, de-alkalizers, chemical feeders) may be necessary for a given application.
- Annual maintenance in a typical application would include draining the unit for removal of any accumulated scale or sludge buildup.
- Minor end-use inefficiencies for electric boilers result from heat loss through the boiler (jacket losses).

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Commercial Gas-Fired Boilers

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Higher typical efficiencies with corresponding cost increases

DATA	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard[1]	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Thermal Efficiency (%)[2]	77	85	80	85	99	84	85	99	93	99	95	99	95	99
Average Life (y)	30	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	15,530	25,910	19,150	25,910	42,670	24,320	25,910	42,670	37,860	42,670	38,950	42,670	38,950	42,670
Total Installed Cost (2022$)	24,600	38,330	30,470	38,330	55,230	35,650	38,330	55,230	50,410	55,230	51,510	55,230	51,510	55,230
Total Installed Cost (2022$/kBtu/h)	40	56	48	56	70	53	56	70	68	70	68	70	68	70
Annual Maintenance Cost (2022$)[3]	1,710	2,100	2,100	2,100	2,140	2,100	2,100	2,140	2,140	2,140	2,140	2,140	2,140	2,140
Annual Maintenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3	3	3	3

1. The standard level shown here is for small (300 kBtu/h to 2500 kBtu/h) gas-fired hot water commercial packaged boilers, which are the most common type of boilers available on the market.
2. DOE's efficiency metric for most boiler types accounts for both flue and jacket losses; previously it did not. DOE continues to uses a combustion efficiency metric instead, for hot water boilers with heat input > 2,500,000 Btu/h.
3. Maintenance costs for 2018 and post-2018 are based on Commercial Packaged Boilers EERE 2020. The annualized maintenance costs estimated in the final rule differ for condensing vs. non-condensing boilers. Appendix 8E of the Commercial Packaged Boilers EERE 2020 TSD provides additional information on how the values are calculated.

Note:
The previous standard went into effect in March 2012.
The current standard went into effect in January 2023.
In December 2016, DOE issued a final rule titled Energy Conservation Program: Energy Conservation Standards for Commercial Packaged Boilers. This rule published in January 2020 with an effective date for January 2023.

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Commercial Gas-Fired Boilers

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- Commercial packaged gas-fired boilers are classified by:
  - Heat input capacity
  - Produce steam or hot water
  - Draft type (natural draft or not) – for steam boilers
- The most common type of commercial gas-fired boilers are small gas-fired hot water boilers with 300,000-2,500,000 Btu/h rated heat input.
- Similar technologies to those used in the residential gas-fired boilers market can be leveraged in the commercial arena. The higher efficiency units typically include electronic ignition, power burners, and improved heat exchangers. Some gas-fired boilers also condense water vapor from the flue gases to improve heating efficiency.
- DOE published a final rule for commercial packaged boilers in January 2020 that updated the efficiency ratings of gas-fired commercial packaged boilers beginning January 2023.
- Advanced Case: Condensing gas-fired boilers are expected to dominate the market by 2030, with corresponding price increases.

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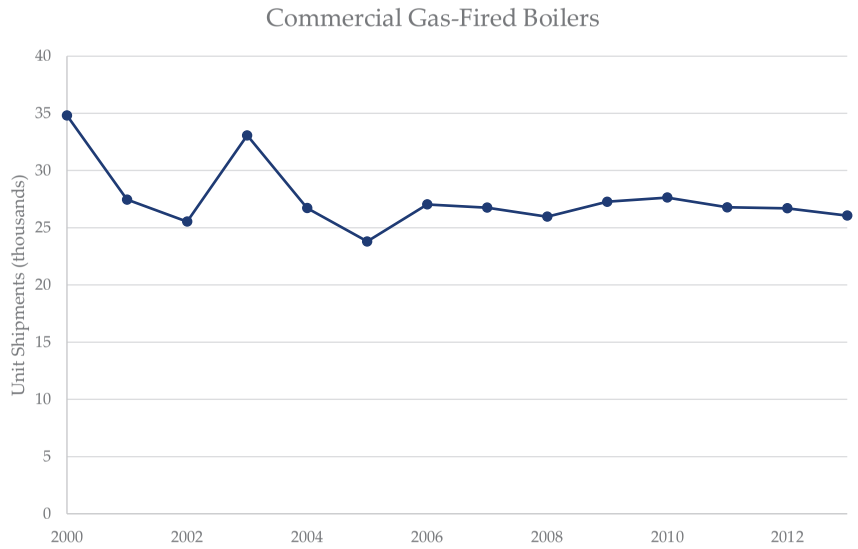
Shipments of commercial gas-fired boilers peaked in 2000 and have been steadily declining since 2010. Shipment data after 2013 is not available.



Source: *Commercial Packaged Boilers EERE 2020*

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Commercial Oil-Fired Boilers

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard[1]	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	1,200	800	800	800	800	800	800	800	800	800	800	800	800	800
Thermal Efficiency (%)[2]	81	85	82	85	97	87	87	97	92	97	92	97	92	97
Average Life (y)	30	25	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)	16,830	26,810	23,190	26,810	51,480	29,730	29,730	51,480	29,730	51,480	29,730	51,480	29,730	51,480
Total Installed Cost (2022$)	22,000	37,240	33,100	37,240	62,910	40,160	40,160	62,910	40,160	62,910	40,160	62,910	40,160	62,910
Total Installed Cost (2022$/kBtu/h)	23	55	50	55	81	58	58	81	55	81	55	81	55	81
Annual Maintenance Cost (2022$)[3]	1,710	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690	2,690
Annual Maintenance Cost (2022$/kBtu/h)	2	4	4	4	3	4	4	3	4	3	4	3	4	3

1. The standard level shown here is for small (300 kBtu/h to 2500 kBtu/h) oil-fired hot water commercial packaged boilers, which are the most common type of boilers available on the market.
2. DOE's efficiency metric for most boiler types accounts for both flue and jacket losses; previously it did not. DOE continues to uses a combustion efficiency metric instead, for hot water boilers with heat input > 2,500,000 Btu/h.
3. Maintenance costs for 2018 and post-2018 are based on Commercial Packaged Boilers EERE 2020. The annualized maintenance costs estimated in the final rule differ for condensing vs. non-condensing boilers. Appendix 8E of the Commercial Packaged Boilers EERE 2020 TSD provides additional information on how the values are calculated.

Note:
The previous standard went into effect in March 2012.
The current standard went into effect in January 2023.
In December 2016, DOE issued a final rule titled Energy Conservation Program: Energy Conservation Standards for Commercial Packaged Boilers. This rule published in January 2020 with an effective date for January 2023.

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Commercial Oil-Fired Boilers

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- Commercial packaged oil-fired boilers are classified by:
  - Heat input capacity
  - Produce steam or hot water
- The most common type of commercial oil-fired boilers are small hot water boilers with 300,000-2,500,000 Btu/h rated heat input.
- The higher efficiency units typically include improved heat exchangers, and multi-step or variable-output power burners.
- DOE published a final rule for commercial packaged boilers in January 2020 that updated the efficiency ratings of oil-fired commercial packaged boilers beginning January 2023.
- Advanced Case: Increased adoption of condensing oil-fired boilers by 2030. However, due to low demand and a shrinking market, costs are expected to remain the same.

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Commercial Oil-Fired Boilers

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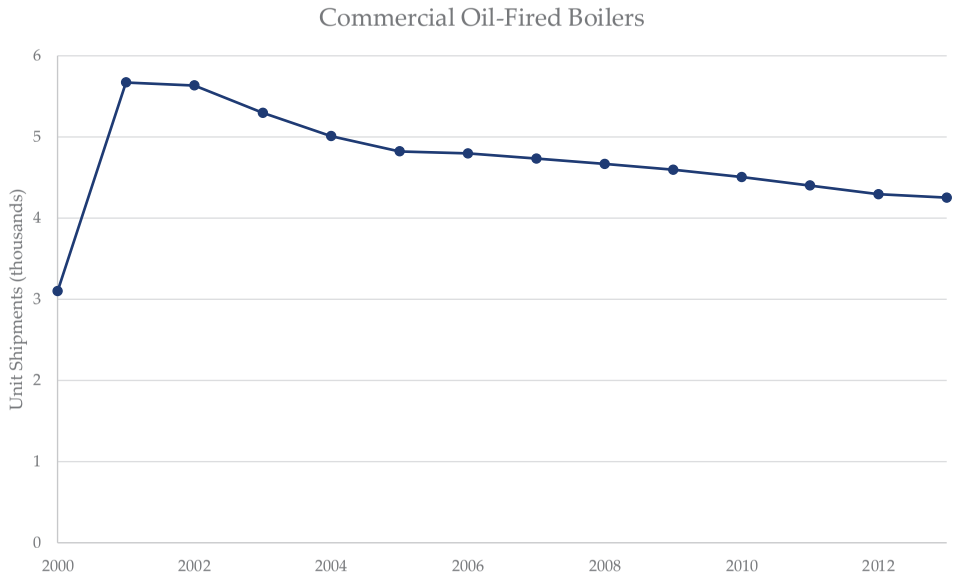
Shipments of commercial oil-fired boilers peaked in 2001 and have been decreasing since then.



Source: *Commercial Packaged Boilers EERE 2020*

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Commercial Centrifugal Chillers (Water-Cooled)

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA	2012	2018	2022[2]			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)[1]	400	400	400	400	400	400	400	400	400	400	400
	600	600	600	600	600	600	600	600	600	600	600
Efficiency [full-load] (kW/ton)	0.66	0.53	0.56	0.52	0.45	0.48	0.42	0.45	0.41	0.44	0.40
Efficiency [IPLV] (kW/ton)	0.61	0.37	0.50	0.31	0.30	0.30	0.28	0.29	0.26	0.28	0.25
COP [full-load]	5.4	6.6	6.3	6.8	7.8	7.3	8.4	7.8	8.6	8.0	8.8
COP [IPLV]	5.9	9.5	7.0	11.3	11.7	11.7	12.6	12.1	13.5	12.6	14.1
Average Life (y)	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$/ton)	380	500	480	500	680	590	760	660	780	690	810
Total Installed Cost (2022$/ton)	440	560	480	560	740	640	820	720	840	740	870
	500	590	540	590	760	670	830	740	860	760	880
Total Installed Cost (2022$/kBtu/h)	39	48	43	48	63	55	69	61	71	63	73
Annual Maintenance Cost (2022$/ton)	30	30	30	30	30	30	30	30	30	30	30
	40	40	40	40	40	40	40	40	40	40	40
Annual Maintenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3

1. Capacity is output.
2. ASHRAE 90.1 data are for units larger than 400 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019). Typical and high efficiency levels are determined based on the range of products currently available on the market.

Note:

For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the integrated part-load value (IPLV)) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.

ASHRAE 90.1 went into effect in October 2019.
Ranges represent the span of typical values for a given parameter.

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Commercial Centrifugal Chillers (Water-Cooled)

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- ASHRAE 90.1-2019 stipulates minimum efficiencies for centrifugal chillers separately from positive displacement water-cooled chillers. They are separated into 5 size categories, with categories divided at: 150, 300, 400, and 600 tons; ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly high full-load consumption in exchange for much lower part-load consumption. For example, for a 600-ton unit:
  - Path A: ≥ 0.56 kW/ton full-load and ≥ 0.50 kW/ton IPLV
  - Path B: ≥ 0.585 kW/ton full-load and ≥ 38 kW/ton IPLV
- Federal Energy Management Program (FEMP) recommendations, last updated in 2020, match ASHRAE 90.1-2019.
- The highest efficiency centrifugal chillers incorporate some of the following:
  - Variable speed drive (VSD) compressors
  - Dedicated heat recovery (heat pump chiller)
  - Magnetic bearing technology (oil-free operation)
  - Greater heat exchanger surface areas; enhanced tube configurations (counterflow)
  - Optimized fluid flow velocities
  - High efficiency electric motors
  - Improved turbomachinery design, resulting in higher compressor efficiency
  - Better piping and valving, including electronic expansion valves
  - Evaporative condenser for the heat rejection equipment
- Installed costs vary widely depending on equipment needed for installation (e.g., crane) and size of system. This is a mature market with centrifugal chillers representing 75% of commercial chiller sales larger than 200 tons.
- Water-cooled chiller ratings do not include energy consumption of the cooling tower and therefore are not directly comparable to rating for air-cooled chillers. Water-cooled centrifugal chillers were selected for analysis due to a higher model share on the AHRI directory in comparison to air-cooled chillers.
- Advanced Case: Due to increases in R&D, improvements in current technology are expected to increase efficiency without substantially increasing costs.

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Commercial Reciprocating Chillers (Air-Cooled Only)

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Same as Reference Case

DATA	2012	2018	2022[2]			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)[1]	100	100	100	100	100	100	100	100	100	100	100
	200	200	200	200	200	200	200	200	200	200	200
Efficiency [full-load] (kW/ton)	1.26	1.19	1.19	1.15	1.00	1.15	1.00	1.15	1.00	1.15	1.00
Efficiency [IPLV] (kW/ton)	1.13	0.86	0.86	0.86	0.80	0.80	0.79	0.80	0.79	0.80	0.79
COP [full-load]	2.8	3.0	3.0	3.0	3.5	3.1	3.5	3.1	3.5	3.1	3.5
COP [IPLV]	3.1	4.1	4.1	4.1	4.5	4.4	4.5	4.4	4.5	4.4	4.5
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$/ton)	725	820	820	820	1,030	820	1,030	820	1,030	820	1,030
	600	730	730	730	880	730	880	730	880	730	880
Total Installed Cost (2022$/ton)	800	880	880	880	1,180	880	1,180	880	1,180	880	1,180
	700	760	760	760	1,090	760	1,090	760	1,090	760	1,090
Total Installed Cost (2022$/kBtu/h)	63	68	68	68	95	68	95	68	95	68	95
Annual Maintenance Cost (2022$/ton)	45	45	50	50	50	45	50	45	50	45	50
	25	25	30	30	30	25	30	25	30	25	30
Annual Maintenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3

1. Capacity is output.
2. ASHRAE 90.1 data are for units larger than 150 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019). Typical and high efficiency levels are determined based on the range of products currently available on the market.

Note:

This analysis covers air-cooled chillers only.

For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.

ASHRAE 90.1 went into effect in October 2019.

Ranges represent the span of typical values for a given parameter.

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Commercial Reciprocating Chillers (Air-Cooled Only)

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- Reciprocating chillers are most cost effective for small loads (30 to 150-ton range). However, reciprocating chiller market share continues to be supplanted by screw and scroll chillers. This trend has accelerated with the phase out of R-22, which was the refrigerant of choice for reciprocating products, which has in turn driven major manufacturers to replace their reciprocating product lines with scroll products (rather than redesign reciprocating products for new refrigerants). As a result, product options are very limited.
- Reciprocating chillers can be used in either air-cooled or water-cooled applications. Reciprocating chillers shown in the data are air-cooled. Air-cooled chillers are less efficient than the water-cooled models. Listed efficiencies include matched condensers and their associated energy use.
- ASHRAE 90.1-2019 stipulates minimum efficiencies for all air-cooled chillers together, including reciprocating chillers, while water-cooled chillers are separated by positive displacement (e.g., reciprocating) versus centrifugal models. Air-cooled chiller efficiencies are further split by size for more and less than 150 tons. ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly lower full-load efficiency in exchange for much higher part-load efficiency. For example, for a 100-ton unit:
  - Path A: ≥ 10.1 EER full-load and ≥ 13.7 IPLV EER
  - Path B: ≥ 9.7 EER full-load and ≥ 15.8 IPLV EER
- FEMP (2022) recommendations for air-cooled chillers are:
  - Path A (<150 tons): ≥ 10.89 EER full-load and ≥ 13.7 IPLV EER
  - Path B (<150 tons): ≥ 9.7 EER full-load and ≥ 16.86 IPLV EER (same as 90.1-2019)
- The highest efficiency reciprocating chillers incorporate some of the following:
  - Multiple compressors for staged capacity control
  - Improved heat-exchangers

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Commercial Screw Chillers (Air-Cooled Only)

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019[1]	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	100	100	100	100	100	100	100	100	100	100	100
	300	300	300	300	300	300	300	300	300	300	300
Efficiency [full-load] (kW/ton)	1.26	1.18	1.19	1.15	0.92	1.11	0.91	0.99	0.86	0.93	0.77
Efficiency [IPLV] (kW/ton)	1.13	0.84	0.86	0.81	0.55	0.77	0.53	0.65	0.49	0.61	0.43
COP [full-load]	2.8	3.0	3.0	3.1	3.8	3.2	3.9	3.6	4.1	3.8	4.6
COP [IPLV]	3.1	4.2	4.1	4.4	6.4	4.5	6.6	5.4	7.2	5.7	8.2
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$/ton)	760	970	1,130	1,130	1,230	1,140	1,230	1,180	1,250	1,200	1,270
	620	850	770	770	870	780	870	820	890	840	910
Total Installed Cost (2022$/ton)	910	1,150	1,250	1,250	1,350	1,260	1,350	1,300	1,370	1,320	1,390
	850	940	820	820	920	830	920	870	940	890	960
Total Installed Cost (2022$/kBtu/h)	73	87	86	86	95	87	95	90	96	92	98
Annual Maintenance Cost (2022$/ton)	50	50	50	50	50	50	50	50	50	50	50
	20	20	20	20	20	20	20	20	20	20	20
Annual Maintenance Cost (2022$/kBtu/h)	3	3	3	3	3	3	3	3	3	3	3

1. ASHRAE 90.1 data for units larger than 150 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019).

Note:
For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.
ASHRAE 90.1 went into effect in October 2019.
Ranges represent the span of typical values for a given parameter.

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Commercial Screw Chillers (Air-Cooled Only)

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- Screw chillers are common in 150 to 500-ton capacities but are most cost effective for small (<300 tons) loads; screw chillers dominate the current market for small to mid-size chillers.
- Screw chillers can be used in either air-cooled or water-cooled applications. Screw chillers shown in the data are air-cooled. Air-cooled chillers are less efficient than the water-cooled models. Listed efficiencies include matched condensers and their associated energy use.
- ASHRAE 90.1-2019 stipulates minimum efficiencies for all air-cooled chillers together, including screw chillers, while water-cooled chillers are separated by positive displacement (e.g., screw) versus centrifugal models. Air-cooled chiller efficiencies are further split by size for more and less than 150 tons. ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly lower full-load efficiency in exchange for much higher part-load efficiency. For example, for a ≥ 150-ton unit:
  - Path A: ≥ 10.1 EER full-load and ≥ 14.0 IPLV EER
  - Path B: ≥ 9.7 EER full-load and ≥ 16.1 IPLV EER
- FEMP recommendations for air-cooled chillers (updated June 2020) are:
  - Path A (≥ 150 tons): ≥ 10.7 EER full-load and ≥ 14.0 IPLV EER
  - Path B (≥ 150 tons): ≥ 9.7 EER full-load and ≥ 16.4 IPLV EER
- The highest efficiency screw chillers incorporate some of the following:
  - Variable speed compressors and/or multiple compressors
  - Economizers
  - Improved heat-exchangers
- Advanced Case: Due to increases in R&D, improvements in current technology are expected to increase efficiency without substantially increasing costs.

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Commercial Scroll Chillers (Air-Cooled Only)

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Higher typical efficiencies with same costs as reference case despite increased efficiency

DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019[1]	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	50	50	50	50	50	50	50	50	50	50	50
	140	140	140	140	140	140	140	140	140	140	140
Efficiency [full-load] (kW/ton)	1.23	1.16	1.19	1.15	1.07	1.08	1.03	1.04	0.99	0.99	0.94
Efficiency [IPLV] (kW/ton)	0.99	0.77	0.88	0.77	0.70	0.71	0.66	0.69	0.63	0.67	0.60
COP [full-load]	2.9	3.0	3.0	3.1	3.3	3.3	3.4	3.4	3.6	3.6	3.7
COP [IPLV]	3.7	4.6	4.0	4.6	5.0	5.0	5.3	5.1	5.6	5.3	5.8
Average Life (y)	20	20	20	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$/ton)	680	1,000	1,060	1,060	1,160	1,120	1,160	1,150	1,200	1,200	1,240
	560	820	530	530	630	590	630	620	670	670	710
Total Installed Cost (2022$/ton)	970	1,210	1,170	1,170	1,270	1,230	1,270	1,260	1,310	1,310	1,350
	850	970	860	860	960	920	960	950	1,000	1,000	1,040
Total Installed Cost (2022$/kBtu/h)	76	91	85	85	93	90	93	92	96	96	100
Annual Maintenance Cost (2022$/ton)	60	60	60	60	60	60	60	60	60	60	60
	40	40	40	40	40	40	40	40	40	40	40
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4

1. ASHRAE 90.1 data for units less than 150 tons and for full-load optimized applications (Path A in ASHRAE 90.1-2019).

Note:
For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.
ASHRAE 90.1 went into effect in October 2019.
Ranges represent the span of typical values for a given parameter.

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Commercial Scroll Chillers (Air-Cooled Only)

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- Scroll chillers range in size from ~20 tons to ~200 tons and can be used in either air-cooled or water-cooled applications. They are the most common type of chiller for small chiller plants. The scroll chillers shown in the data are air-cooled, which is most common. Air-cooled chillers are less efficient than the water-cooled models. Listed efficiencies include matched condensers and their associated energy use.
- ASHRAE 90.1-2019 stipulates minimum efficiencies for all air-cooled chillers together, including scroll chillers, while water-cooled chillers are separated by positive displacement (e.g., scroll) versus centrifugal models. Air-cooled chiller efficiencies are distinct for more and less than 150 tons. ASHRAE 90.1-2019 also distinguishes between whether the unit will be optimized for full-load (Path A) or part-load operation (Path B). Data here are for Path A; a Path B chiller may have slightly lower full-load efficiency in exchange for much higher part-load efficiency. For example, for a 100-ton unit:
  - Path A: ≥ 10.1 EER full-load and ≥ 13.7 IPLV EER
  - Path B: ≥ 9.7 EER full-load and ≥ 15.8 IPLV EER
- FEMP recommendations for air-cooled chillers (updated June 2020) are:
  - Path A (< 150 tons): ≥ 10.7 EER full-load and ≥ 13.7 IPLV EER
  - Path B (< 150 tons): ≥ 9.7 EER full-load and ≥ 15.9 IPLV EER
- The highest efficiency scroll chillers incorporate some of the following:
  - Multiple compressors for staged capacity control
  - Improved heat-exchangers
  - Variable speed compressor (or other modulation controls)
- With the phase out of R-22, manufacturers have replaced many of their small reciprocating chiller products with equivalent scroll products, making them a primary choice for small tonnage applications.
- Advanced Case: Due to increases in R&D, improvements in current technology are expected to increase efficiency without substantially increasing costs.

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Commercial Gas-Fired Chillers (Water-Cooled, Direct-Fired Only)

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Same as Reference Case

DATA	2012		2018		2022				2030		2040		2050	
	Installed Base: Absorption	Installed Base: Engine-Driven	Installed Base: Absorption	Installed Base: Engine-Driven	ASHRAE 90.1-2019 Absorption	CA Title 24 – Engine-Driven	Absorption	Engine-Driven	Absorption	Engine-Driven	Absorption	Engine-Driven	Absorption	Engine-Driven
Typical Capacity (tons)[1]	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	1,500	400	1,500	400	1,500	400	1,500	400	1,500	400	1,500	400	1,500	400
COP [full-load]	1.1	1.7	1.2	1.7	1.0	1.2	1.2	1.7	1.3	1.8	1.4	1.8	1.4	1.8
COP [IPLV]	NA	NA	1.6	2.6	1.0	2.0	1.6	2.6	1.6	2.6	1.6	2.6	1.6	2.6
Average Life (y)	23	25	23	25	23	25	23	25	23	25	23	25	23	25
Retail Equipment Cost (2022$/ton)	1,060	1,000	1,060	1,000	1,200	1,000	1,200	1,000	1,200	1,000	1,200	1,000	1,200	1,000
	880	880	880	880	870	880	870	880	870	880	870	880	870	880
Total Installed Cost (2022$/ton)	1,290	1,240	1,180	1,240	1,110	1,240	1,110	1,240	1,110	1,240	1,110	1,240	1,110	1,240
	1,000	1,000	1,000	1,000	850	1,000	850	1,000	850	1,000	850	1,000	850	1,000
Total Installed Cost (2022$/kBtu/h)	95	93	91	93	82	93	82	93	82	93	82	93	82	93
Annual Maintenance Cost (2022$/ton)	40	60	40	60	40	60	40	60	40	60	40	60	40	60
	20	40	20	40	20	40	20	40	20	40	20	40	20	40
Annual Maintenance Cost (2022$/kBtu/h)	3	4	3	4	3	4	3	4	3	4	3	4	3	4

1. Capacity is output.

Note:
This analysis assumes a water-cooled chiller; both gas-fired chiller types (absorption and engine-driven) are shown. COP values for double-effect absorption chillers are shown.
For most chillers (including those in single-chiller applications and for peaking units in multi-chiller applications), the seasonal performance (represented by the IPLV) is more indicative of annual expected performance than the full-load performance; performance of baseload chillers in multi-chiller applications, which typically operate at full-load, are well represented by the full-load efficiency value.
ASHRAE 90.1 went into effect in October 2019.
CA Title 24 went into effect in January 2020.
Ranges represent the span of typical values for a given parameter.

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Commercial Gas-Fired Chillers (Water-Cooled, Direct-Fired Only)

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- Gas-fired chillers are available as either air-cooled (~25-50 tons) or water-cooled (150+ tons). This analysis covers only water-cooled chillers of two varieties: absorption and engine-driven vapor compression (direct-fired only; indirect steam or hot water driven units are excluded).
- Direct gas firing provides high enough temperatures to operate double effect absorption chillers, which operate at a 50-60% higher COP than single effect systems. Triple effect chillers, though not commercially available, can boost cooling COP 30-50% beyond double effect chillers. Some companies have worked on prototype direct-fired triple effect absorption chillers, but prohibitively high cost of advanced high heat/corrosion-resistant materials required for triple effect absorption chillers suggests that this technology will not likely have an impact on the market in the near-term.
- Gas-fired engine-driven chillers pair conventional vapor compression systems (typically screw or centrifugal compressors) with natural gas powered-reciprocating engines. They exhibit higher peak cooling COP than absorbers, and engine modulation results in better part-load performance. Future efficiency improvements for engine-driven chillers are not anticipated. Engine-driven chillers allow the opportunity to recover waste heat for useful purposes.
- Maintenance costs for engine-driven chillers are higher than for other chillers because they include all the typical components of a vapor compression chiller in addition to an engine; the engine maintenance costs vary depending on the annual run hours of the unit.
- Limited sales data suggest that the U.S. market for gas-fired chillers is very limited and is mostly for replacement units, not for new installations. Recent increases in electric chiller efficiency have narrowed the operating cost differential with gas chillers. Asia has the majority of the global gas-fired chiller market.
- Gas-fired chiller installations are particularly valuable in locations where electric rates are high and gas prices are low (i.e., low spark spread), where digester or landfill gas sources are available, or where waste heat sources are available (e.g., an industrial process or microturbine CHP system) that could be used with a hybrid direct/indirect-fired absorption chiller to offset the use of natural gas.

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Commercial Rooftop Air Conditioners

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Higher efficiencies with same costs as reference case despite increased efficiency

DATA	2012	2018	2022[4]				2023				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Output Capacity (kBtu/h)	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Part Load Efficiency (IEER)[1]	12.4	12.9	12.9	12.9	14.0	23.3	14.8	14.8	18.0	23.3	16.0	23.3	16.5	23.3	17.5	23.3
Efficiency (EER)[2]	10.6	11.5	11.5	11.5	12.2	12.8	12.2	12.2	12.7	12.8	12.6	12.8	12.6	12.8	12.7	12.8
Efficiency Conversion	3.6	3.8	3.8	3.8	4.1	6.8	4.3	4.3	5.3	6.8	4.7	6.8	4.8	6.8	5.1	6.8
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	7,760	8,280	8,280	8,280	9,090	12,210	9,490	9,490	10,340	12,210	9,590	12,210	9,590	12,210	9,590	12,210
Total Installed Cost (2022$)	10,350	11,870	11,870	11,870	13,020	17,600	13,560	13,560	14,970	17,600	13,720	17,600	13,720	17,600	13,720	17,600
Total Installed Cost (2022$/kBtu/h)	115	132	132	132	145	196	151	151	166	196	152	196	152	196	152	196
Annual Maintenance Cost (2022$)[3]	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370	370
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4

1. Values shown are for air-cooled small commercial packaged air conditioners with either electric resistance heating or no heating within the same enclosure. DOE published a direct final rule for commercial packaged air conditioners and heat pumps in January 2016 with initial standards becoming effective in 2018 and additional standards becoming effective in 2023. As part of this rulemaking, DOE changed the regulated metric from EER to integrated energy efficiency ratio (IEER).
2. DOE investigated the relationship between IEER and EER. Because the relationship between IEER and EER is weak, this analysis estimates EER values based on the average of the values seen at a given IEER.
3. Examples of annual maintenance services include, check tensions, condition, and alignment of belts and adjust as necessary; lubricate shaft and motor bearings; replace air filters; clean coils, drain pan and piping, blowers, fan motors as required; check refrigerant pressure and compressor oil level; etc.
4. The 2022 typical efficiency is based on the average IEER from DOE's CCD. The 2022 high efficiency is based on the most-efficient model in DOE's CCD, but costs are estimated based on the most efficient unit analyzed in CUAC EERE 2016, which had an IEER of 21.5.

Note:
EER is the ratio of the cooling capacity (in Btu/h) to the power input (in watts) and provides a measure of the efficiency of equipment operating at full load (i.e., 100 percent cooling capacity) in high-ambient-temperature conditions (i.e., 95 °F). IEER is a single number part-load efficiency based on weighting of EER at various load capacities. Efficiency Conversion is the conversion of IEER from a [(Btu/h)/W] metric to a metric in the same units.
The previous standard went into effect in January 2018. The current standard went into effect in January 2023.
ENERGY STAR V. 3.1 went into effect in January 2018. ENERGY STAR V. 4.0 went into effect in January 2023.

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Commercial Rooftop Air Conditioners

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- Air-Cooled Commercial Packaged Air Conditioners

Cooling Capacity (kBtu/h)	Heating Type	Federal Standard Effective 1/1/2018 Min. IEER	Federal Standard Effective 1/1/2023 Min. IEER
Small (≥ 65 and < 135)	Electric resistance or none	12.9	14.8
	Any other type	12.7	14.6
Large (≥ 135 and < 240)	Electric resistance or none	12.4	14.2
	Any other type	12.2	14.0

- This analysis focused on small air-cooled commercial packaged rooftop air conditioners (90 kBtu/h or 7.5 tons), though there are also standards for many other types of commercial air conditioners.
- Amended standards in terms of IEER for all equipment classes took effect in January 2018. More stringent standards in terms of IEER for all equipment classes took effect in January 2023.
- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more cost-effective variable speed technology) are expected to increase efficiency without substantially increasing costs.

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Commercial Gas-Fired Engine-Drive Rooftop Air Conditioners

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Same as Reference Case

DATA	2012[1]	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (tons)	18	11	11	11	11	11
Heating COP	1.4	1.4	1.4	1.4	1.4	1.4
Cooling COP	0.9	1.2	1.2	1.2	1.2	1.2
Average Life (y)	15	15	15	15	15	15
Retail Equipment Cost ($/ton)	3,350	2,820	3,710	3,710	3,710	3,710
Total Installed Cost ($/ton)	3,820	3,290	4,110	4,110	4,110	4,110
Total Installed Cost ($/kBtu/h)	318	274	343	343	343	343
Annual Maintenance Cost (2022$)	70	70	70	70	70	70
Annual Maintenance Cost (2022$/kBtu/h)	6	6	6	6	6	6

1. The 2012 typical capacity and cooling COP were estimated as a simple average between obsolete pre-2003 units and 2013 units, which first became available in 2010; this assumes that each vintage represents about half of the installed base.

Note:
Only one product was available in 2012; the market has grown slightly in years since. Typical capacity and COP for 2018 and later are averages of units available as of 2017.

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Commercial Gas-Fired Engine-Drive Rooftop Air Conditioners

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- There are only a few gas-fired engine-driven rooftop units currently available in the U.S. market. The first unit was introduced in 2010. It is an 11-ton packaged heat pump with dual scroll compressors, variable refrigerant flow, and a variable speed supply fan. Engine coolant heat recovery improves the heating mode COP.
- There are currently no Federal requirements on gas-fired engine-driven rooftop air conditioners or heat pumps.
- Annual sales of the engine-driven rooftop heat pump are estimated at less than 5,000 units per year.

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Commercial Rooftop Heat Pumps

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Higher efficiencies with same costs as reference case despite increased efficiency

DATA	2012	2018	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Part Load Efficiency (IEER)[1]	12.0	11.3	12.2	14.3	12.8	20.3	14.1	15.3	20.3	14.4	20.3	15.3	20.3	15.3	20.3
EER	10.2	11.2	11.3	11.5	11.8	13.0	12.0	11.8	13.0	11.7	13.1	11.7	13.1	11.7	13.1
COP (Heating)	3.3	3.3	3.3	3.4	3.4	3.7	3.4	3.5	3.7	3.4	3.7	3.5	3.7	3.5	3.7
Average Life (y)	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	7,490	7,490	9,000	10,250	9,370	12,920	10,160	10,600	12,920	10,290	12,920	10,600	12,920	10,600	12,920
Total Installed Cost (2022$)	9,340	9,340	12,900	14,940	13,530	18,860	14,810	15,510	18,860	15,000	18,860	15,510	18,860	15,510	18,860
Total Installed Cost (2022$/kBtu/h)	104	104	143	166	150	210	165	172	210	167	210	172	210	172	210
Annual Maintenance Cost (2022$)	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4

1. Values shown are for air-cooled small commercial packaged heat pumps with either electric resistance heating or no heating within the same enclosure. DOE published a direct final rule for commercial packaged air conditioners and heat pumps in January 2016 with initial standards becoming effective in 2018 and additional standards becoming effective in 2023. As part of this rulemaking, DOE changed the regulated metric from EER to IEER.

Note:
The previous standard went into effect in January 2018. The current standard went into effect in January 2023.
ENERGY STAR V. 3.1 went into effect in January 2018. ENERGY STAR V. 4.0 went into effect in January 2023.

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Commercial Rooftop Heat Pumps

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- Air-Cooled Commercial Packaged Heat Pumps

Cooling Capacity (kBtu/h)	Heating Type	Federal Standard Effective 1/1/2018 Min. IEER	Federal Standard Effective 1/1/2023 Min. IEER
Small (≥ 65 and < 135)	Electric resistance or none	12.2	14.1
	Any other type	12.0	13.9
Large (≥ 135 and < 240)	Electric resistance or none	11.6	13.5
	Any other type	11.4	13.3

- This analysis focused on small air-cooled commercial packaged rooftop heat pumps (90 kBtu/h or 7.5 tons), though there are also standards for many other types of commercial heat pumps.
- Amended standards in terms of IEER for all equipment classes took effect in 2018. More stringent standards in terms of IEER for all equipment classes took effect in 2023.
- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more cost-effective variable speed technology) are expected to increase efficiency without substantially increasing costs.

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Commercial Ground-Source Heat Pumps

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Same efficiencies with lower costs than reference case despite same efficiency

DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	48	48	48	48	48	48	48	48	48	48	48
COP (Heating)[1]	3.1	3.7	3.2	3.5	3.6	3.5	3.6	3.5	3.6	3.5	3.6
EER (Cooling)[2]	12.7	17.4	14.1	17.0	21.6	17.0	21.6	17.0	21.6	17.0	21.6
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8
	21	21	21	21	21	21	21	21	21	21	21
Retail Equipment Cost (2022$)	10,470	6,470	5,590	6,470	7,880	6,470	7,880	6,470	7,880	6,470	7,880
Total Installed Cost (2022$)	19,760	18,230	17,350	18,230	19,650	16,410	17,690	16,410	17,690	16,410	16,410
	44,820	26,520	25,580	26,520	27,880	23,870	25,090	23,870	25,090	23,870	23,870
Total Installed Cost (2022$/kBtu/h)	673	466	447	466	495	420	446	420	446	420	420
Annual Maintenance Cost (2022$)	180	180	180	180	180	180	180	180	180	180	180
Annual Maintenance Cost (2022$/kBtu/h)	4	4	4	4	4	4	4	4	4	4	4

1. COP values listed are assessed at a "ground loop" test condition, which is representative of closed loop GSHP operating conditions. However, DOE sets standards at a "water loop" test condition. The AHRI directory lists COP ratings at both sets of test conditions and is used to convert between them where necessary.
2. EER values listed are assessed at a full-load "ground loop" test condition, which is representative of closed loop GSHP operating conditions. However, DOE sets standards at a full-load "water loop" test condition. The AHRI directory lists EER ratings at all sets of test conditions and is used to convert between them where necessary.

Note:
Residential and commercial GSHPs are very similar - the main difference in data presented is the different capacity (3-ton vs. 4-ton) and slightly higher installation costs for commercial GSHP. DOE does not distinguish between residential and commercial units in its regulations.

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Commercial Ground-Source Heat Pumps

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- The most common commercial ground-source heat pump systems are closed-loop in which water or anti-freeze solution is circulated through plastic pipes buried underground. Commercial water-to-air heat pumps (WAHPs) range in size from 1 ton or less to over 500 tons depending on whether a distributed or centralized architecture is used. Distributed systems are more prevalent.
- Most geothermal WAHPs are rated for capacity and efficiency based on the ISO 13256-1 standard. Heating and cooling efficiency measurements under this standard include input energy for fans and pumps on a proportional basis that only includes that power required to transport air and liquid through the heat pump. The reason for this method is to simplify comparisons between heat pumps and to allow equipment to be optimized for real world conditions without suffering rating penalties. Real world energy use will exceed ratings predictions as a result of higher fluid static pressure requirements.
- ISO 13256-1 cooling rating conditions require 77 °F entering water temperature and 80.6 °F entering air temperature. More typical peak design criteria would be 80-90 °F entering water temperature and 75 °F entering air temperature. As a result, ISO 13256-1 rated cooling efficiency would be higher than typical design peak operation.
- Some WAHPs include efficiency data for a part-load operating condition as allowed by ISO 13256-1 for multiple stage or variable speed compressors. No seasonal energy efficiency metric (analogous to SEER or IEER) currently applies to WAHPs. The annual performance of a geothermal WAHP system can vary more widely than for other system types due to the large influence of ground loop design and characteristics.
- The ENERGY STAR criteria for ground-source heat pumps apply only to residential applications.
- Installation cost is for a closed loop system and includes necessary accessories. The ground loop heat exchanger and distribution pumping systems represent a majority of the installation cost.
- Low end WAHPs utilize single stage compressors. Higher efficiency units incorporate multiple stage or variable speed compressor controls to improve efficiency as well as humidity and temperature control. Variable speed ECM fan motors also improve overall energy efficiency.
- Advanced Case: Ground-source heat pumps are already highly efficient and have not changed much in terms of efficiency in recent years. With increased R&D, it is anticipated that the equipment and installation costs will be reduced over time, but efficiency will likely stay the same.

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Packaged Terminal Air Conditioners

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Same as Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High[2]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)[1]	9	9	9	9	9	9	9	9	9	9	9
Efficiency (EER)	11.3	11.3	11.3	11.3	13.1	11.3	13.1	11.3	13.1	11.3	13.1
Efficiency	3.3	3.3	3.3	3.3	3.8	3.3	3.8	3.3	3.8	3.3	3.8
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8
Retail Equipment Cost (2022$)	1,460	1,460	1,460	1,460	1,560	1,460	1,560	1,460	1,560	1,460	1,560
Total Installed Cost (2022$)	1,740	1,740	1,740	1,740	1,840	1,740	1,840	1,740	1,840	1,740	1,840
Total Installed Cost (2022$/kBtu/h)	193	193	193	193	204	193	204	193	204	193	204
Annual Maintenance Cost (2022$)	70	70	70	70	70	70	70	70	70	70	70
Annual Maintenance Cost (2022$/kBtu/h)	8	8	8	8	8	8	8	8	8	8	8

1. Typical capacity is representative of units with the most shipments. It was also the representative cooling capacity for DOE's analysis in packaged terminal air conditioners (PTAC) and packaged terminal heat pumps (PTHP) EERE 2022 NOPD.
2. High values for 2022 and beyond are based on the max-tech level from PTAC & PTHP EERE 2022 NOPD.

Note:
The current standard went into effect in January 2017.

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Packaged Terminal Air Conditioners

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- PTAC are a self-contained, ductless air conditioning system used for commercial applications.
- Analysis was conducted for the standard equipment class at the representative cooling capacity of 9000 Btu/h.

Cooling Capacity (kBtu/h)	Equipment Size	Equipment Class	Federal Standard EER
PTAC	Standard	< 7000	11.9
		≥7,000 Btu/h and ≤15,000 Btu/h	14.0 – (0.3 x Cap)
		> 15,000 Btu/h	9.5

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Packaged Terminal Heat Pumps

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Higher efficiencies with the same costs as ref. case despite increased efficiency

DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical[2]	High[3]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)[1]	9	9	9	9	9	9	9	9	9	9	9
Efficiency (EER)	11.3	11.3	11.3	11.3	13.1	11.5	13.1	12.0	13.1	12.4	13.1
Efficiency	3.3	3.3	3.3	3.3	3.8	3.4	3.8	3.5	3.8	3.6	3.8
COP (Heating)	3.2	3.2	3.2	3.2	3.6	3.3	3.6	3.4	3.6	3.5	3.6
Average Life (y)	8	8	8	8	8	8	8	8	8	8	8
Retail Equipment Cost (2022$)	1,620	1,620	1,620	1,620	1,720	1,630	1,720	1,630	1,720	1,630	1,720
Total Installed Cost (2022$)	1,910	1,910	1,910	1,910	2,010	1,910	2,010	1,910	2,010	1,910	2,010
Total Installed Cost (2022$/kBtu/h)	212	212	212	212	223	212	223	212	223	212	223
Annual Maintenance Cost (2022$)	70	70	70	70	70	70	70	70	70	70	70
Annual Maintenance Cost (2022$/kBtu/h)	8	8	8	8	8	8	8	8	8	8	8

1. Typical capacity is representative of units with the most shipments. It was also the representative cooling capacity for DOE's analysis in PTAC & PTHP EERE 2022 NOPD.
2. Typical values for 2022 and beyond are based on the efficiency level that has the largest market share per PTAC & PTHP EERE 2022 NOPD.
3. High values for 2022 and beyond are based on the max-tech level from PTAC & PTHP EERE 2022 NOPD.

Note:
The current standard went into effect in October 2012.

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Packaged Terminal Heat Pumps

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- PTHP are self-contained heat pumps primarily used for commercial applications.
- Analysis was conducted for the standard equipment class at the representative cooling capacity of 9000 Btu/h.

Cooling Capacity (kBtu/h)	Equipment Size	Equipment Class	Federal Standard EER	Federal Standard COP
PTHP	Standard	< 7000	11.9	3.3
		≥7,000 Btu/h and ≤15,000 Btu/h	14.0 – (0.3 x Cap)	3.7 – (0.052 x Cap)
		> 15,000 Btu/h	9.5	2.9
PTHP	Non-Standard	< 7000	9.3	2.7
		≥7,000 Btu/h and ≤15,000 Btu/h	10.8 – (0.213 x Cap)	2.9 – (0.026 x Cap)
		> 15,000 Btu/h	7.6	2.5

- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more cost-effective variable speed technology) are expected to increase efficiency without substantially increasing costs.

Commercial Water Heating

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Commercial Gas-Fired Storage Water Heaters

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Same as Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Typical Storage Capacity (gal)	100	100	100	100	100	100	100	100	100	100	100	100
Typical Input Capacity (kBtu/h)	199	199	199	199	199	199	199	199	199	199	199	199
Thermal Efficiency (%)[1]	81	82	80	82	94	99	95	99	95	99	95	99
Average Life (y)	13	10	10	10	10	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)	3,870	3,890	3,850	3,890	4,180	4,290	4,200	4,290	4,200	4,290	4,200	4,290
	5,170	5,200	5,140	5,200	5,530	5,650	5,550	5,650	5,550	5,650	5,550	5,650
Total Installed Cost (2022$)	5,170	5,190	5,140	5,190	6,630	6,730	6,640	6,730	6,640	6,730	6,640	6,730
	8,440	8,460	8,410	8,460	8,590	8,710	8,610	8,710	8,610	8,710	8,610	8,710
Total Installed Cost (2022$/kBtu/h)	42	42	43	42	41	39	40	39	40	39	40	39
Annual Maintenance Cost (2022$)[2]	320	320	320	320	330	330	330	330	330	330	330	330
Annual Maintenance Cost (2022$/kBtu/h)	2	2	2	2	2	2	2	2	2	2	2	2

1. Different levels of standby loss were not included in this analysis.
2. Maintenance consists of sediment and scale removal once or twice per year and replacement of miscellaneous components such as gaskets and sealants. Condensing units have an additional cost for replacement of condensate neutralizer media every two years.

Note:
The current standard went into effect in October 2015.
ENERGY STAR V. 2.0 went into effect in October 2018.
The range of retail and installed costs represent the range from replacement market to new construction market.

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Commercial Gas-Fired Storage Water Heaters

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- Input capacity > 155 kBtu/h and storage capacity ≤ 140 gal
- Federal standard:
  - Minimum thermal efficiency: 80%
  - Maximum standby loss (Btu/h) : Input Rate/800 + 110 × (Rated Volume)$^{1/2}$
- ENERGY STAR requirements:
  - Minimum thermal efficiency: 94%
  - Maximum standby loss (Btu/h): 0.84 × [(Input Rate/800) + 110 × (Rated Volume)$^{1/2}$]
- Baseline units are typically constructed similarly to residential units, though with higher input capacities (and often higher storage volumes).
- High-efficiency units include condensing heat exchangers (typically stainless or enameled steel) to extract additional heat by condensing water vapor in flue gases. Condensing units also include an inducer fan system or power burner. The heat exchanger is typically contained within the tank, but some designs consist of an external heating module attached to a storage tank. Condensing units are expected to be the majority market share by 2030.
- Maintenance consists of sediment and scale removal once or twice per year and replacement of miscellaneous components such as gaskets and sealants. Condensing units have an additional cost for replacement of condensate neutralizer media every two years.

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Commercial Gas-Fired Storage Water Heaters

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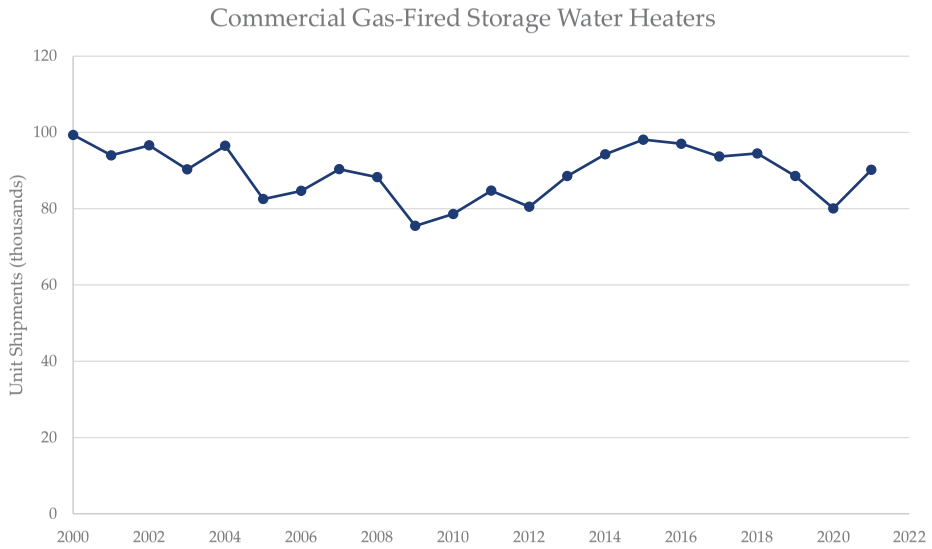
Annual shipments have fluctuated from 99,000 units in 2000 to 75,000 units in 2009, back to 99,000 units in 2015 and gradually decreasing since then until 2020.



Source: CWH EERE 2022 NOPR and AHRI

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Commercial Electric Resistance Storage Water Heaters

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Same as Reference Case

DATA	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Storage Capacity (gal)	119	119	119	119	119	119	119
Typical Input Capacity (kW)[1]	18	18	18	18	18	18	18
Typical Input Capacity (kBtu/h)	60	60	60	60	60	60	60
Thermal Efficiency (%)	98	98	98	98	98	98	98
Average Life (y)	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)	3,180	3,180	3,180	3,180	3,180	3,180	3,180
	3,750	3,750	3,750	3,750	3,750	3,750	3,750
Total Installed Cost (2022$)	4,460	4,460	4,460	4,460	4,460	4,460	4,460
	4,690	4,690	4,690	4,690	4,690	4,690	4,690
Total Installed Cost (2022$/kBtu/h)	76	76	76	76	76	76	76
Annual Maintenance Cost (2022$)	50	50	50	50	50	50	50
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1

1. Different levels of standby loss were not included in this analysis.

Note:
No new standards rulemaking has been initiated for commercial electric resistance water heaters since CWH EERE 2016 NOPR. Accordingly, the results are the same as EIA Technology Forecast Updates (2018), updated to 2022$.
The range of retail equipment and installed costs represents the range from replacement market to new construction market.

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Commercial Electric Resistance Storage Water Heaters

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- Federal standard:
  - Maximum standby loss (%/h) : 0.30 + 27/Measured Storage Volume
  - Minimum thermal efficiency: no standard, but all units have an efficiency ≥ 98%
- Storage capacity: typically, 50 to 120 gallons, though smaller and larger units exist for specialized applications
- Commercial units are typically constructed similar to residential units, though with higher input capacities (and often higher storage volumes).
- There is very little variation in thermal efficiency on the market; variation in standby loss is typically due to tank design and insulation thickness.
- Maintenance consists of sediment and scale removal once or twice per year.

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Commercial Electric Resistance Storage Water Heaters

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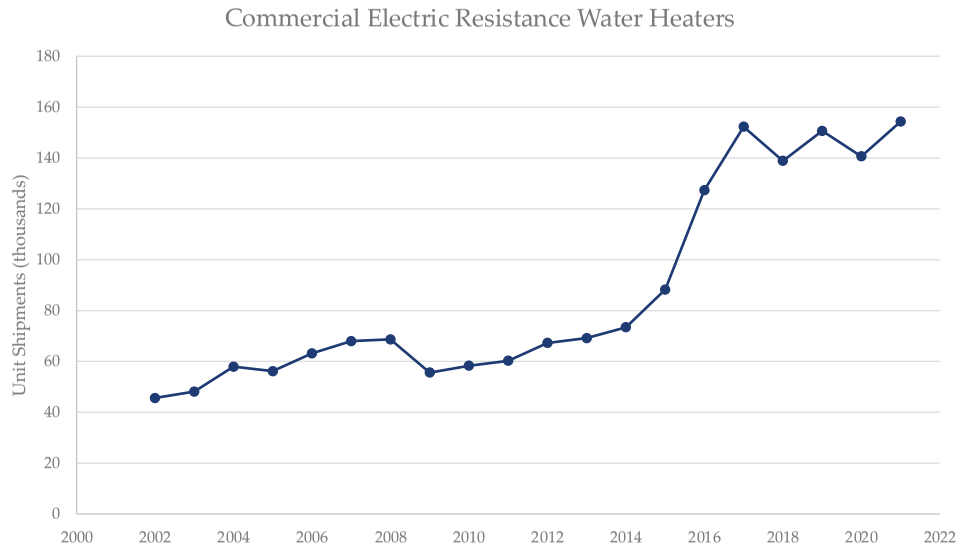
Annual shipments increased by almost 50% between 2002 and 2008. After a small dip in shipments in 2009, annual shipments have increased by about 173% between 2009 and 2017, stabilizing between 140-150 thousand shipments per year since then.



Source: AHRI

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Commercial Heat Pump Water Heaters

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Higher typical efficiencies with the same costs as reference case despite increased efficiency

DATA	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.0	Typical	Typical	Typical
Water Flow Rate (gal/min)[1]	34	34	34	34	34	34	34
Typical Output Capacity (kW)[1]	50	50	50	50	50	50	50
Typical Output Capacity (kBtu/h)	171	171	171	171	171	171	171
Coefficient of Performance (COP_h)	3.9	3.9	3.9	3.0	4	4.2	4.4
Average Life (y)	15	15	15	15	15	15	15
Retail Equipment Cost (2022$)[2]	55,406	55,406	55,406	55,406	55,406	55,406	55,406
Total Installed Cost (2022$)[2]	59,935	59,935	59,935	59,935	59,935	59,935	59,935
Total Installed Cost (2022$/kBtu/h)	350	350	350	350	350	350	350
Annual Maintenance Cost (2022$)[2]	120	120	120	120	120	120	120
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1

1. Water flow rate scales with typical capacity. The storage tanks must be purchased and installed separately from the HP unit. The typical output and flow rate provided are near the median of the products available on the market currently.
2. Costs are same as EIA Technology Forecast Updates (2018), updated to 2022$. Updated representative costs for commercial heat pump water heaters are not available due to the extremely small market for these products.

Note:
ENERGY STAR V. 2.0 went into effect in October 2018.

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Commercial Heat Pump Water Heaters

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- Typical commercial HPWHs (CHPWHs) are add-on units designed to be used with a storage tank(s); integrated CHPWHs have emerged on the market (i.e., heat pump module and storage tank combined in one unit) in recent years.
- CHPWHs serve only a small portion of the commercial water heating (CWH) market, with the ENERGY STAR database listing only two manufacturers, each with one basic model listed.
- CHPWHs can extract heat from either air or water for heating potable water ("air-source" or "water-source"). The capacity of air-source CHPWHs falls at lower ambient air temperatures.
- Air-source CHPWHs cool the surrounding air, which can be desirable when installed indoors in applications with a year-round cooling load (e.g., a commercial kitchen).
- Output capacities for CHPWHs range from 17 kW to over 70 kW for air-source units and over 600 kW for water-source units.
- Some commercial applications require water as hot as 180 °F, such as dishwashing; however, most CHPWHs cannot deliver hot water at temperatures higher than 150 °F.
- There are no current Federal standards for CHPWHs, but DOE prescribes a test procedure for determining COP_h for CHPWHs.
- The most recent ENERGY STAR V. 2.0 specification for CWH equipment went into effect in October 2018. It specifies a COP_h level of 3.0 for CHPWHs.
- Advanced Case: Due to increases in R&D, improvements in current technology (e.g., more cost-effective variable speed technology) are expected to increase efficiency without substantially increasing costs.

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Commercial Oil-Fired Storage Water Heaters

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Same as Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Storage Capacity (gal)	70	85	85	85	85	85	85	85	85	85	85
Typical Input Capacity (kBtu/h)	300	300	300	300	300	300	300	300	300	300	300
Thermal Efficiency (%)[1]	79	81	80	81	82	81	82	81	82	81	82
Average Life (y)	13	13	13	13	13	13	13	13	13	13	13
Retail Equipment Cost (2022$)	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470	5,470
Total Installed Cost (2022$)	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120	6,120
Total Installed Cost (2022$/kBtu/h)	26	25	26	25	25	25	25	25	25	25	25
Annual Maintenance Cost (2022$)	200	200	200	200	200	200	200	210	210	210	210
Annual Maintenance Cost (2022$/kBtu/h)	1	1	1	1	1	1	1	1	1	1	1

1. Different levels of standby loss were not included in this analysis.

Note:
The commercial oil-fired water heaters market is very small; currently, there are only 4 basic models in DOE's CCD. DOE's rulemaking analysis for oil-fired water heaters has not been updated since 2001. The retail, installed, and maintenance costs have been updated from EIA Technology Forecast Updates (2018) to 2022$.
The current standard went into effect in October 2015.

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Commercial Oil-Fired Storage Water Heaters

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- Input capacity > 155 kBtu/h and storage capacity ≤ 140 gal
- Federal standard:
  - Minimum thermal efficiency: 80%
  - Maximum standby loss (Btu/h) : Input Rate/800 + 110 × (Rated Volume)$^{1/2}$
- Condensing units do not exist, thus the highest thermal efficiency on the market is 82%.
- Commercial units are typically constructed similar to residential units, though with higher input capacities (and often higher storage volumes).
- Maintenance costs include sediment and scale removal once or twice per year.
- The market for commercial oil-fired storage water heaters is very small; shipments are approximately 3% of shipments for commercial gas-fired storage water heaters.

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Commercial Electric Booster Water Heaters

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Same as Reference Case

DATA	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (gal)	6	6	6	6	6	6
	16	16	16	16	16	16
Typical Output Capacity (kBtu/h)	1,374	1,374	1,374	1,374	1,374	1,374
Thermal Efficiency (%)	98	98	98	98	98	98
Average Life (y)	3	3	3	3	3	3
	10	10	10	10	10	10
Retail Equipment Cost (2022$)[1]	1,530	1,530	1,920	1,920	1,920	1,920
	3,290	3,530	4,560	4,560	4,560	4,560
Total Installed Cost (2022$)[1]	1,730	1,730	2,120	2,120	2,120	2,120
	3,490	3,730	4,760	4,760	4,760	4,760
Total Installed Cost (2022$/kBtu/h)	2	2	3	3	3	3
Annual Maintenance Cost (2022$)[2]	-	-	-	-	-	-
Annual Maintenance Cost (2022$/kBtu/h)	-	-	-	-	-	-

1. The 2012 and 2018 installed base costs are the same as EIA Technology Forecast Updates (2018), updated to 2022$. Retail costs for 2022 and later are based on the range of costs for products on the market today. Installed costs assume a $200 installation price.
2. Maintenance costs are negligible.

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Commercial Gas-Fired Booster Water Heaters

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Higher efficiencies with corresponding cost increases

DATA	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Capacity (gal)	3	3	3	3	3	3	3
	5	5	5	5	5	5	5
Typical Output Capacity (kBtu/h)	500	500	500	500	500	500	500
Thermal Efficiency (%)[1]	80	80	80	80	80	91	80
Average Life (y)	5	5	5	5	5	5	5
	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)[2]	5,530	5,760	7,130	7,130	7,130	9,500	7,130
	8,000	9,060	11,120	11,120	11,120	12,500	11,120
Total Installed Cost (2022$)[2]	5,830	6,060	7,430	7,430	7,430	9,800	7,430
	8,300	9,360	11,420	11,420	11,420	12,800	11,420
Total Installed Cost (2022$/kBtu/h)	14	15	19	19	19	23	19
Annual Maintenance Cost (2022$)	160	160	160	160	160	160	160
Annual Maintenance Cost (2022$/kBtu/h)	0	0	0	0	0	0	0

1. While EIA Technology Forecast Updates (2018) included high values reflecting condensing models, models currently available in the market do not exceed 80% efficiency.
2. The 2012 and 2018 installed base costs are the same as EIA Technology Forecast Updates (2018), updated to 2022$. Retail costs for 2022 and later are based on the range of costs for products on the market today. Installed costs assume a $300 installation price.

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Commercial Booster Water Heaters

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- Booster water heaters are installed, often at the point of use, in series with the main service water heating system to boost service water temperatures. The main service water heating system may provide 110-140 °F water, and the booster water heater may increase that temperature to 180-195 °F. Typical commercial applications for booster water heaters include commercial dishwashers, laundromats, hospitals, and car washes.
- Commercial booster water heaters are regulated by DOE as either storage or instantaneous water heaters, depending on the ratio of input capacity to storage volume. Units with input capacity < 4,000 Btu/h per gallon of stored water are storage water heaters; all other units are instantaneous water heaters.
- DOE's regulations do not currently include standards for electric instantaneous water heaters, but standards are included for electric storage water heaters, gas-fired instantaneous water heaters, and gas-fired storage water heaters.
- Condensing gas-fired booster water heaters, those with an efficiency of 90% of more, were analyzed previously. There are no condensing units currently on the market. Condensing gas-fired booster water heaters can only operate if the incoming water temperature is below 130 °F so there is enough heat transfer to condense.
- Booster water heaters typically have short lifetimes because of high usage and extreme temperatures.
- Shipments are small due to the limited number of applications.
- Advanced Case: increased high efficiencies are possible due to market incentives to re-introduce condensing commercial gas-fired booster water heaters through additional investment, research, and development. No significant changes otherwise.

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Commercial Gas-Fired Instantaneous Water Heaters

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Same as Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High[2]	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	250	250	250	250	250	250	250	250	250	250	250	250
	399	399	399	399	399	399	399	399	399	399	399	399
Thermal Efficiency (%)	80	92	80	92	94	99	96	99	96	99	96	99
Average Life (y)	17	17	17	17	17	17	17	17	17	17	17	17
	25	25	25	25	25	25	25	25	25	25	25	25
Retail Equipment Cost (2022$)[1]	1,630	1,840	1,630	1,840	1,880	7,990	1,930	7,990	1,930	7,990	1,930	7,990
	4,400	8,610	4,400	8,610	9,000	9,990	9,400	9,990	9,400	9,990	9,400	9,990
Total Installed Cost (2022$)[1]	2,430	3,980	2,430	3,980	4,010	13,000	4,070	13,000	4,070	13,000	4,070	13,000
	10,380	13,560	10,380	13,560	13,950	14,950	14,350	14,950	14,350	14,950	14,350	14,950
Total Installed Cost (2022$/kBtu/h)	25	29	25	29	29	44	30	44	30	44	30	44
Annual Maintenance Cost (2022$)[3]	90	100	90	100	100	820	100	820	100	820	100	820
	760	820	760	820	820	830	830	830	830	830	830	830
Annual Maintenance Cost (2022$/kBtu/h)	2	2	2	2	2	3	1	3	1	3	1	3

1. Commercial gas-fired instantaneous water heaters are categorized into two groups: tankless water heater and hot water supply boiler. Tankless units are similar in design to residential tankless units. The hot water supply boiler has a much higher input and is similar in design to boilers. The large variation of total input capacity and design causes a large range of costs. The range of retail, installed, and maintenance costs represent the differences in design, as well as the cost ranges arising from replacement versus new construction markets.
2. High efficiency was determined based on DOE's CCD. The most efficient tankless water heater has a thermal efficiency of 96%. The most efficient hot water supply boiler has a thermal efficiency of 99%.
3. Maintenance consists replacement of miscellaneous components such as gaskets and sealants. Condensing units have an additional cost for replacement of condensate neutralizer media every two years.

Note:
For the installed base, current standard, and typical costs, low values represent costs for tankless water heaters in the replacement market while high values represent costs for hot water supply boilers in the new construction market. The range of costs for the High values are estimated costs for hot water supply boilers in the replacement and new construction market.
ENERGY STAR V. 2.0 went into effect in October 2018.

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Commercial Gas-Fired Instantaneous Water Heaters

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- Storage Capacity < 10 gallons and ≥ 10 gallons
- Federal standard:
  - Minimum thermal efficiency: 80%
  - Maximum standby loss (Btu/h): Input Rate/800 + 110 x (Rated Volume)$^{1/2}$
- ENERGY STAR requirements:
  - Minimum thermal efficiency: 94%
- Wall-mounted ("tankless") units typically do not exceed ~400,000 Btu/h and are similar in design to residential tankless units. Floor-mounted units ("circulating" or "volume" water heaters) are similar in design to boilers and can have input capacities in the millions of Btu/h. Floor-mounted units are typically installed with a storage tank.
- Despite high available input capacities, some installations use multiple units staged together, which may have reliability and/or efficiency benefits.
- Similar to storage water heaters, higher efficiencies are achieved with condensing operation, which requires a condensing heat exchanger and inducer fan or power burner. Some units include both non-condensing and condensing heat exchangers, while others include a single condensing heat exchanger.
- When replacing a storage water heater with an instantaneous water heater, there may be significant additional costs to upsize the gas supply line and change the venting.

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Commercial Gas-Fired Instantaneous Water Heaters

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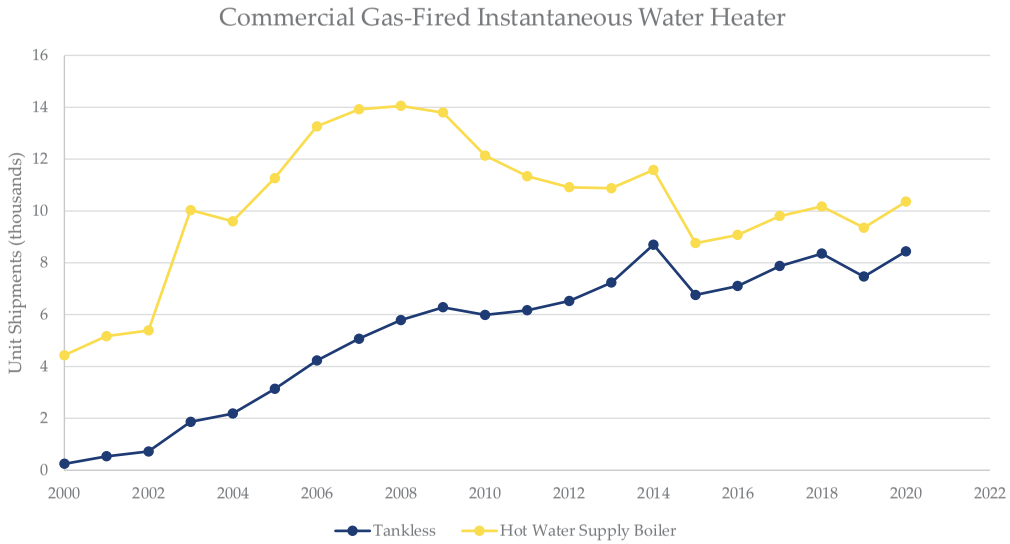
Annual shipments for gas-fired instantaneous tankless water heaters have gradually increased since 2000 while those for gas-fired instantaneous hot water supply boiler water heaters peaked in 2008 and have been decreasing since then, recently stabilizing around 10,000 annual shipments.



Source: CWH EERE 2022 NOPR

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Commercial Solar Water Heaters

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Same as Reference Case

DATA	2012	2018	2022		2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	ENERGY STAR V. 5.0	Typical	Typical	Typical
Typical Capacity (sq. ft.)[1]	85	85	85	85	85	85	85	85
Typical Capacity (m^2)	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90
Typical Capacity (Input) (kBtu/h) – North	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05
Typical Capacity (Input) (kBtu/h) – South	6.74	6.74	6.74	6.74	6.74	6.74	6.74	6.74
Solar Uniform Energy Factor (SUEF)[2]	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Average Life (y)	20	20	20	20	20	20	20	20
Retail Equipment Cost (2022$)[3]	10,470	10,470	10,280	10,280	10,280	10,280	10,280	10,280
Total Installed Cost (2022$)[3]	14,180	14,180	12,640	12,640	12,640	12,640	12,640	12,640
Total Installed Cost (2022$/kBtu/h) – North	936	936	834	834	834	834	834	834
Total Installed Cost (2022$/kBtu/h) – South	702	702	626	626	626	626	626	626
Annual Maintenance Cost (2022$)[4]	100	100	100	100	100	100	100	100
Annual Maintenance Cost (2022$/kBtu/h) - North	7	7	7	7	7	7	7	7
Annual Maintenance Cost (2022$/kBtu/h) - South	5	5	5	5	5	5	5	5

1. Typical capacity refers to the solar collector panel area. It was determined using the SRCC database as the average value of the largest bin (in terms of capacity) with the greatest number of units.
2. In 2020, the efficiency metric for solar water heaters changed from SEF to SUEF. There is no equation or scaling factor readily available to translate SEF to SUEF. Accordingly, for the 2012 and 2018 installed base, SUEF was determined using the 2020 ENERGY STAR data set assuming the typical SEF/SUEF value was similar between 2012-2020. For 2022 and beyond, due to lack of SUEF data, it is assumed that a typical electric backup unit would meet the ENERGY STAR criteria. ENERGY STAR specifies a minimum SUEF of 3.0 for electric backup units and 1.8 for gas backup units.
3. Costs are for an indirect (active closed loop) system, including tank and backup heater. Smaller capacity/cost systems are typical for southern & western states (>two-third of the current market). Higher capacity/cost systems are required in colder/cloudier regions. The 2012 and 2018 installed base costs are updated from EIA Technology Forecast Updates (2018) to 2022$.
4. Annual maintenance is expected to be 0.5% to 1% of the total installation.

Note:
ENERGY STAR V. 4.0 went into effect in January 2022. ENERGY STAR V. 5.0 will go into effect in April 2023 but the ENERGY STAR criteria for solar water heaters will remain the same in ENERGY STAR V. 5.0.

Commercial Solar Water Heaters

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- In 2020, a diverse group of stakeholders from the solar thermal industry developed the SUEF Specification for solar water heaters. The goal of this specification is to align with the UEF metric used by DOE for other water heating technologies.
- SUEF is also the metric used by the current ENERGY STAR Specification, and it replaced the SEF metric.
- EIA Technology Forecast Updates (2018) presented results using SEF and solar fraction (SF). SEF is currently not used in either the ENERGY STAR or SRCC databases; accordingly, this report presents results according to SUEF. SF is the portion of the total conventional hot water heating load (delivered energy and tank standby losses). SF varies from 0 to 1.0. Typical solar fraction values are 0.5–0.75.
- There is no equation or scaling factor readily available to translate SEF to SUEF. Accordingly, for the 2012 and 2018 installed base, SUEF was determined using the 2020 ENERGY STAR data set assuming the typical SEF/SUEF value was similar between 2012-2020. For 2022 and beyond, SUEF is the average SUEF for solar water heaters with a "high-usage" draw pattern from the current ENERGY STAR qualified product list.
- Commercial solar water heaters are typically custom designed for a specific installation.
- Commercial solar water heaters may include backup heating, from sources such as electric resistance or hydronic heat (supplied from a gas-fired boiler or geothermal heat pump).
- Storage volumes of tanks for commercial solar water heaters can span from 140 gallons to over 2,000 gallons.
- SRCC's OG-300 can be used to certify commercial systems, but most commercial systems are larger and unique; this certification program is mostly used for residential solar water heaters.
  - Many incentive programs require that solar collectors for commercial systems be certified to SRCC's certification program for collectors, OG-100.

Commercial Cooking Products

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Commercial Natural Gas Range with Griddle and Oven

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Higher typical efficiencies with the same costs as ref. case despite increased efficiency

DATA	2012	2018	2022			2023	2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2[1]	High	ENERGY STAR V. 3.0[2]	Typical	High	Typical	High	Typical	High
Griddle - Cooking Energy Efficiency (%)	30	30	40	38	69	NA	42	69	44	69	46	69
Oven - Cooking Energy Efficiency (%)	35	35	35	46	69	49	39	69	42	69	47	69
Range - Cooking Energy Efficiency (%)	30	30	30	NA	40	NA	33	40	36	40	39	40
Combined Energy Efficiency (%)[3]	31	31	35	NA	58	NA	38	58	41	58	44	58
Griddle - Normalized Idle Energy Rate (Btu/h/ft^2)	3,000	3,000	3,000	2,650	1,724	NA	2,700	1,724	2,450	1,724	2,200	1,724
Oven - Idle Energy Rate (Btu/h)	18,000	18,000	18,000	12,000	3,516	9,500	16,200	3,516	14,600	3,516	13,150	3,516
Range - Idle Energy Rate (Btu/h)	3,600	3,600	3,600	NA	1,900	NA	3,250	1,900	2,950	1,900	2,650	1,900
Combined Idle Energy Rate (Btu/h)[3]	10,350	10,350	10,350	NA	4,178	NA	9,319	4,178	8,431	4,178	7,581	4,178
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
Total Installed Cost (2022$)	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940	8,940
Total Installed Cost (2022$/kBtu/h)	864	864	864	NA	2,140	NA	959	2,140	1,060	2,140	1,179	2,140
Annual Maintenance Cost (2022$)[5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. ENERGY STAR does not cover combination products that include griddles, ranges, and ovens in one single package. The ENERGY STAR levels provided here reflect specifications for individual products. Range tops are not covered by ENERGY STAR.
2. ENERGY STAR V. 3.0 updated the requirements for commercial ovens from V. 2.2, effective January 2023. Data shown is reflective of a standard full-size convection oven that holds 5 or more pans.
3. Combined energy efficiency and combined idle energy rate are calculated as a weighted average of each component using typical daily operating hours sourced from Food Service Technology Center (FSTC). Typical daily operating hours are assumed to be 12 hours for the griddle component, 8 hours for the oven component, and 12 hours for the range component.
4. Products in the commercial cooking market generally do not scale in price with relation to cooking efficiency. Distributors also do not provide this information.
5. Maintenance costs are negligible.

Note:
ENERGY STAR V. 2.2 went into effect in October 2015. ENERGY STAR V. 3.0 went into effect in January 2023.

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Commercial Electric Range with Griddle and Oven

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Higher typical efficiencies with the same costs as ref. case despite increased efficiency

DATA	2012	2018	2022			2023	2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2[1]	High	ENERGY STAR V. 3.0[2]	Typical	High	Typical	High	Typical	High
Griddle - Cooking Energy Efficiency (%)	65	70	72	70	91	NA	74	91	76	91	78	91
Oven - Cooking Energy Efficiency (%)	65	65	65	71	86	76	67	86	69	86	71	86
Range - Cooking Energy Efficiency (%)	75	75	75	NA	87	NA	77	87	80	87	81	87
Combined Energy Efficiency (%)[3]	69	71	71	NA	88	NA	73	88	76	88	77	88
Griddle - Normalized Idle Energy Rate (kW/ft^2)	0.44	0.34	0.30	0.32	0.21	NA	0.29	0.21	0.28	0.21	0.27	0.21
Oven - Idle Energy Rate (kW)	1.5	1.5	1.5	1.6	0.6	1.4	1.4	0.6	1.3	0.6	1.2	0.6
Range - Idle Energy Rate (kW)[4]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Combined Idle Energy Rate (kW)[3]	1.7	1.4	1.3	1.4	0.8	NA	1.3	0.8	1.2	0.8	1.1	0.8
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[5]	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230	11,230
Total Installed Cost (2022$)	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410	11,410
Total Installed Cost (2022$/kBtu/h)	2,019	2,362	2,533	2,375	4,423	NA	2,662	4,423	2,805	4,423	2,964	4,423
Annual Maintenance Cost (2022$)[6]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. ENERGY STAR does not cover combination products that include griddles, ranges, and ovens in one single package. The ENERGY STAR levels provided here reflect specifications for individual products. Range tops are not covered by ENERGY STAR.
2. ENERGY STAR V. 3.0 updates the requirements for commercial ovens from V. 2.2, effective January 12, 2023. Data shown is reflective of a standard full-size convection oven that holds 5 or more pans.
3. Combined energy efficiency and combined idle energy rate are calculated as a weighted average of each component using typical daily operating hours sourced from FSTC. Typical daily operating hours are assumed to be 12 hours for the griddle component, 8 hours for the oven component, and 12 hours for the range component.
4. No data on electric range top idle energy rates.
5. Products in the commercial cooking market generally do not scale in price with relation to cooking efficiency. Distributors also do not provide this information.
6. Maintenance costs are negligible.

Note:
ENERGY STAR V. 2.2 went into effect in October 2015. ENERGY STAR V. 3.0 goes into effect in January 2023.

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Commercial Ranges with Griddle and Oven

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- Combined product that typically includes 2-6 range tops, a 24 in. x 24 in. griddle surface, and one or two half- or full-size ovens.
- Combined product is not covered by ENERGY STAR. However, the individual product ENERGY STAR V. 2.2 specifications are provided below.

Product	ENERGY STAR V. 2.2 Requirements	Gas	Electric
Griddle	Cooking Energy Efficiency	≥ 38%	≥ 70%
	Normalized Idle Energy Rate	≤ 2,650 Btu/h per ft^2	≤ 0.320 kW per ft^2
Oven	Cooking Energy Efficiency	≥ 46%	≥ 71%
	Idle Energy Rate	≤ 12,000 Btu/h	Half size: ≤1.00 kW Full size: ≤1.60 kW

- ENERGY STAR does not provide certification for range tops.
- There are no Federal standards for commercial cooking products.
- Product pricing in this market do not scale with efficiency, but rather depend on a number of other factors such as brand name, aesthetics, and additional features.

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Commercial Ranges with Griddle and Oven

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- ENERGY STAR V. 3.0 requirements for commercial ovens went into effect in January 2023:

Product	ENERGY STAR Requirements	Gas	Electric
Oven	Cooking Energy Efficiency	≥ 49%	Half size: ≥ 71% Full size: ≥ 76%
	Idle Energy Rate	≤ 9,500 Btu/h	Half size: ≤1.00 kW Full size ≥ 5 Pans: ≤1.40 kW Full size ≤ 5 Pans: ≤1.00 kW

- Advanced Case: Increased market incentives are expected to drive efficiency improvements. However, because cost does not scale with efficiency, there is no significant expected change in cost.

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Commercial Ranges with Griddle and Oven

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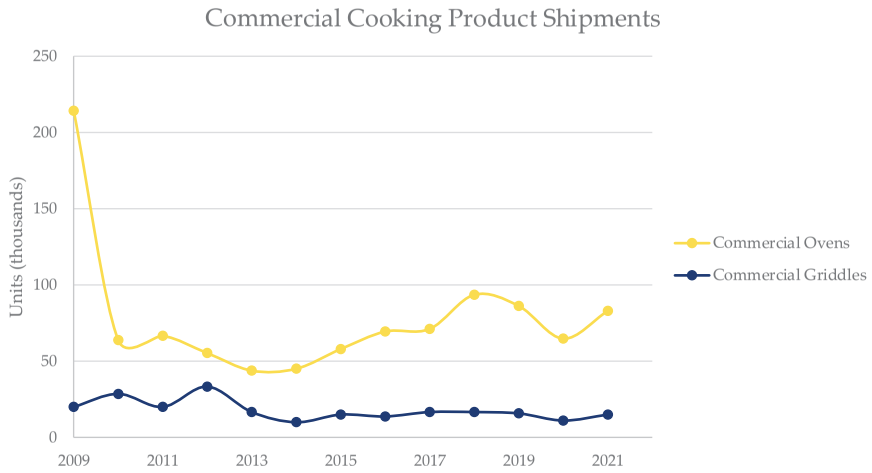
Commercial oven shipments have gradually increased since 2013, following a peak in 2009. Commercial griddle shipments have remained steady since 2014.



Source: *ENERGY STAR (Unit Shipment Data)*

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Commercial Hot Food Holding Cabinets – Small

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Higher typical efficiencies with the same costs as ref. case despite increased efficiency

DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Interior Volume (ft^3)[1]	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Maximum Idle Energy Rate (W)[2]	312	312	312	312	168	168	250	168	200	168	200	168
Annual Energy Use (kWh/y)[3]	1,025	1,025	1,025	1,025	552	552	820	552	656	552	656	552
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	3,200	3,200	3,200	3,200	3,800	3,800	3,200	3,800	3,200	3,800	3,200	3,800
Total Installed Cost (2022$)[5]	3,200	3,200	3,200	3,200	3,800	3,800	3,200	3,800	3,200	3,800	3,200	3,800
Total Installed Cost (2022$/kBtu/h)	8,016	8,016	8,016	8,016	17,677	17,677	10,020	17,677	12,524	17,677	12,524	17,677
Annual Maintenance Cost (2022$)[5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. Interior volume is characterized by the product size classes reported by ENERGY STAR. The small size class covers units with interior volume less than 13 ft^3. Interior volume for the small size class was determined based on the units in the ENERGY STAR database, accessed February 2023.
2. Maximum idle energy rate is a function of interior volume. For the small size class, ENERGY STAR and high values were determined for a representative 7.8 ft^3 using the ENERGY STAR database, accessed February 2023. The typical value was assumed to be equivalent to the state standard for a representative 7.8 ft^3 unit.
3. Annual energy use is determined using the latest FEMP data from December 2021, which assumes that a typical 22.4 ft^3 commercial hot food holding cabinet uses an average of 9 hours per day and 365 days per year. The small size class is assumed to use the same number of annual usage hours as the medium size class.
4. Retail equipment costs were determined using distributor information for undercounter, half-size, and full-size hot food holding cabinets.
5. Additional installation costs and maintenance costs are negligible.

Note:
ENERGY STAR V. 2.0 went into effect in October 2011 and was revised in December 2022. Massachusetts, Nevada, and Rhode Island state standards have adopted the ENERGY STAR V. 2.0 criteria that went into effect in October 2011. The majority of state standards (California, Colorado, Connecticut, DC, Maryland, New Hampshire, Oregon, Rhode Island, Vermont, and Washington) implement the ENERGY STAR V. 1.0 specification that went into effect in August 2003, which is recorded in the table. ENERGY STAR V. 1.0 specifies a maximum idle energy rate of 40 W per cubic foot of interior volume.

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Commercial Hot Food Holding Cabinets – Medium

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Higher typical efficiencies with the same costs as ref. case despite increased efficiency

DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Interior Volume (ft^3)[1]	21.4	21.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4
Maximum Idle Energy Rate (W)[2]	900	856	896	896	299	298	717	298	573	298	459	298
Annual Energy Use (kWh/y)[3]	2,957	2,812	2,943	2,943	982	979	2,355	979	1,884	979	1,507	979
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	2,940	4,530	4,600	4,600	5,000	5,000	4,600	5,000	4,600	5,000	4,600	5,000
Total Installed Cost (2022$)[5]	2,940	4,530	4,600	4,600	5,000	5,000	4,600	5,000	4,600	5,000	4,600	5,000
Total Installed Cost (2022$/kBtu/h)	2,553	4,136	4,012	4,012	13,078	13,113	5,015	13,113	6,269	13,113	7,836	13,113
Annual Maintenance Cost (2022$) [5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. Interior volume is characterized by the product size classes reported by ENERGY STAR. The medium size class covers units with interior volume between 13 ft^3 to 28 ft^3. For the medium size class, the interior volume increase from 21.4 ft^3 to 22.4 ft^3 in 2022 reflects the current representative product volume reported by FEMP, last updated December 2021.
2. Maximum idle energy rate is a function of interior volume. For the medium size class, the maximum idle energy rate for 2022 onward is reflective of a representative 22.4 ft^3 unit, using the latest FEMP data from December 2021.
3. Annual energy use is determined using the latest FEMP data from December 2021, which assumes that a typical 22.4 ft^3 commercial hot food holding cabinet uses an average of 9 hours per day and 365 days per year.
4. Retail equipment costs were determined using distributor information for undercounter, half-size, and full-size hot food holding cabinets.
5. Additional installation costs and maintenance costs are negligible.

Note:
ENERGY STAR V. 2.0 went into effect in October 2011 and was revised in December 2022. Massachusetts, Nevada, and Rhode Island state standards have adopted the ENERGY STAR V. 2.0 criteria that went into effect in October 2011. The majority of state standards (California, Colorado, Connecticut, DC, Maryland, New Hampshire, Oregon, Rhode Island, Vermont, and Washington) implement the ENERGY STAR V. 1.0 specification that went into effect in August 2003, which is recorded in the table. ENERGY STAR V. 1.0 specifies a maximum idle energy rate of 40 W per cubic foot of interior volume.

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Commercial Hot Food Holding Cabinets – Large

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Higher typical efficiencies with the same costs as ref. case despite increased efficiency

DATA	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Interior Volume (ft^3)[1]	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0
Maximum Idle Energy Rate (W)[2]	1,333	1,333	1,760	1,333	400	310	1,067	310	853	310	683	310
Annual Energy Use (kWh/y)[3]	4,380	4,380	5,782	4,380	1,314	1,018	3,504	1,018	2,803	1,018	2,243	1,018
Average Life (y)	12	12	12	12	12	12	12	12	12	12	12	12
Retail Equipment Cost (2022$)[4]	5,500	5,500	5,500	5,500	6,000	6,000	5,500	6,000	5,500	6,000	5,500	6,000
Total Installed Cost (2022$)[5]	5,500	5,500	5,500	5,500	6,000	6,000	5,500	6,000	5,500	6,000	5,500	6,000
Total Installed Cost (2022$/kBtu/h)	3,224	3,224	2,442	3,224	11,723	15,126	4,030	15,126	5,037	15,126	6,296	15,126
Annual Maintenance Cost (2022$)[5]	–	–	–	–	–	–	–	–	–	–	–	–
Annual Maintenance Cost (2022$/kBtu/h)	–	–	–	–	–	–	–	–	–	–	–	–

1. Interior volume is characterized by the product size classes reported by ENERGY STAR. The large size class covers units with interior volume greater than or equal to 28 ft^3. Interior volume for the large size class was determined based on the units in the ENERGY STAR database, accessed February 1, 2023.
2. Maximum idle energy rate is a function of interior volume. For the large size class, ENERGY STAR and high values were determined using the ENERGY STAR database, and the typical value uses the assumption that ENERGY STAR units are reported to be 70% more efficient than typical units.
3. Annual energy use is determined using the latest FEMP data from December 2021, which assumes that a typical 22.4 ft^3 commercial hot food holding cabinet uses an average of 9 hours per day and 365 days per year. The large size class is assumed to use the same number of annual usage hours as the medium size class.
4. Retail equipment costs were determined using distributor information for undercounter, half-size, and full-size hot food holding cabinets.
5. Additional installation costs and maintenance costs are negligible.

Note:
ENERGY STAR V. 2.0 went into effect in October 2011 and was revised in December 2022. Massachusetts, Nevada, and Rhode Island state standards have adopted the ENERGY STAR V. 2.0 criteria that went into effect in October 2011. The majority of state standards (California, Colorado, Connecticut, DC, Maryland, New Hampshire, Oregon, Rhode Island, Vermont, and Washington) implement the ENERGY STAR V. 1.0 specification that went into effect in August 2003, which is recorded in the table. ENERGY STAR V. 1.0 specifies a maximum idle energy rate of 40 W per cubic foot of interior volume.

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Commercial Hot Food Holding Cabinets

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- Hot food holding cabinets are used in commercial kitchens to keep food warm until it is served.
- While available in many shapes and sizes, interior volumes around 21.4 ft^3 were reported as typical in many settings in EIA Technology Forecast Updates (2018). FEMP currently lists 22.4 ft^3 as a representative unit size.
- Annual unit energy consumption can range from < 1,000 to > 30,000 kWh/y, depending on size, efficiency, and usage.
- Energy performance metric is "Idle Energy Consumption Rate" in Watts, measured using ASTM Standard F2140-11.
- There are no Federal standards for hot food holding cabinets, but seven States have identical standards.
  - The first State standard took effect in California in 2006; this standard is now considered the typical or "baseline" product. It is also equivalent to the ENERGY STAR V. 1.0 Specification that went into effect in August 2003.
  - ENERGY STAR V. 2.0 went into effect in October 2011.
- Maximum Idle Energy Consumption Rate for products $12 \leq V < 28$:
  - State standards: $\leq 40 \times V$ (baseline)
  - ENERGY STAR V. 2.0: $\leq 2.0 \times V + 254$ (about 65% below baseline)

  where V is interior volume in ft^3.
- The most efficient products are about 80% below baseline.
- Energy savings achieved with insulation, automatic door closers, magnetic door gaskets, and Dutch doors (half-doors).
- Advanced Case: Increased market incentives are expected to drive efficiency improvements. However, because cost does not scale with efficiency, there is no significant expected change in cost.

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Commercial Hot Food Holding Cabinets

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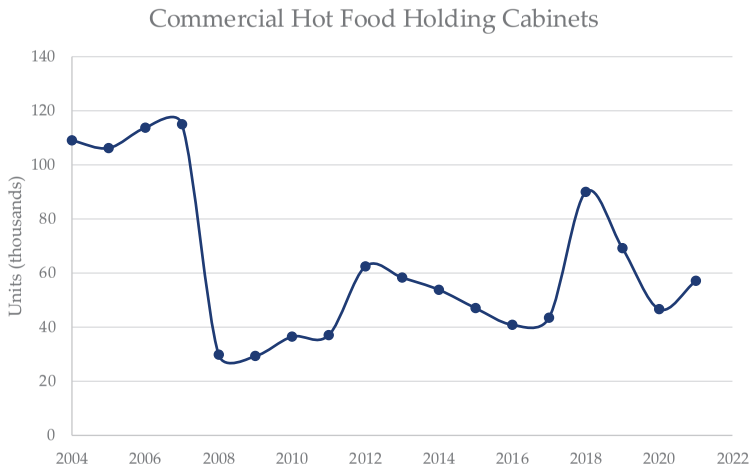
Commercial hot food holding cabinet shipments peaked in 2007 at 115,000 units, followed by a peak of 90,000 units in 2019.



Source: *ENERGY STAR (Unit Shipment Data)*

Appendix A
Data Sources

Guidehouse
1676 International Drive
McLean, VA 22102

And

Leidos
11951 Freedom Drive
Reston, VA 20190

Residential Space Heating and Cooling

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Residential Gas-Fired Furnaces (North)

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (North) V. 4.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	Residential Furnaces EERE 2022 NOPR								
AFUE (%)	CFR			DOE CCD	ENERGY STAR V. 4.1	DOE CCD	Residential Furnaces EERE 2022 NOPR		
Electric Consumption (kWh/y)	Residential Furnaces EERE 2016		Residential Furnaces EERE 2022 NOPR						
Average Life (y)	Residential Furnaces EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Residential Furnaces EERE 2016		Residential Furnaces EERE 2022 NOPR						
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Gas-Fired Furnaces (Rest of Country)

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR (ROC) V. 4.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	Residential Furnaces EERE 2022 NOPR								
AFUE (%)	CFR		DOE CCD	ENERGY STAR V. 4.1	DOE CCD	Residential Furnaces EERE 2022 NOPR			
Electric Consumption (kWh/y)	Residential Furnaces EERE 2016	Residential Furnaces EERE 2022 NOPR							
Average Life (y)	Residential Furnaces EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Residential Furnaces EERE 2016	Residential Furnaces EERE 2022 NOPR							
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Oil-Fired Furnaces

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	Residential Furnaces EERE 2011								
AFUE (%)	CFR		DOE CCD	ENERGY STAR V. 4.1	DOE CCD				
Electric Consumption (kWh/y)	Residential Furnaces EERE 2011								
Average Life (y)									
Retail Equipment Cost (2022$)									
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Gas-Fired Boilers

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical / High		
Typical Input Capacity (kBtu/h)	Boilers EERE 2016	Boilers EERE 2022 Preliminary Analysis							
AFUE (%)		Boilers EERE 2022 Preliminary Analysis		DOE CCD	ENERGY STAR V. 3.0	Boilers EERE 2022 Preliminary Analysis			
Electric Consumption (kWh/y)		Boilers EERE 2022 Preliminary Analysis							
Average Life (y)									
Retail Equipment Cost (2022$)									
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Oil-Fired Boilers

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.0	High	Typical / High		
Typical Input Capacity (kBtu/h)	Boilers EERE 2016	Boilers EERE 2022 Preliminary Analysis					Guidehouse		
AFUE (%)		Boilers EERE 2022 Preliminary Analysis		DOE CCD	ENERGY STAR V. 3.0	Boilers EERE 2022 Preliminary Analysis			
Electric Consumption (kWh/y)		Boilers EERE 2022 Preliminary Analysis							
Average Life (y)									
Retail Equipment Cost (2022$)									
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Electric Resistance Furnaces

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical		
Typical Input Capacity (kBtu/h)	Distributors				Guidehouse		
AFUE (%)	DOE / ASHRAE						
Average Life (y)	Distributors						
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)	Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse						

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Residential Electric Resistance Unit Heaters

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SOURCES	2015	2020	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical		
Typical Capacity (kBtu/h)	Distributors		Utilities/Distributors	Guidehouse		
Efficiency (%)	DOE		DOE			
Average Life (y)	Guidehouse		Guidehouse			
Retail Equipment Cost (2022$)			Distributors			
Total Installed Cost (2022$)			Home Remodeling Service			
Annual Maintenance Cost (2022$)			Guidehouse			

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Residential Central Air Conditioners – North (Not Hot-Dry or Hot-Humid)

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SOURCES	2015	2020	2022				2023			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	CAC and HP EERE 2016									Guidehouse		
SEER	CAC and HP EERE 2016 / Guidehouse		CFR	DOE CCD	ENERGY STAR V. 5.0	CAC and HP EERE 2016	RESNET		CAC and HP EERE 2016			
SSER2	RESNET						CAC and HP EERE 2016	ENERGY STAR V. 6.1	RESNET			
Average Life (y)	CAC and HP EERE 2016											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)	CAC and HP EERE 2016 / Less (2021)											
Annual Maintenance Cost (2022$)	CAC and HP EERE 2016											

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Residential Central Air Conditioners – South (Hot-Dry and Hot-Humid)

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SOURCES	2015	2020	2022				2023			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	High	Typical / High		
Typical Input Capacity (kBtu/h)	CAC and HP EERE 2016									Guidehouse		
SEER	CAC and HP EERE 2016 / Guidehouse		CFR	DOE CCD	ENERGY STAR V. 5.0	CAC and HP EERE 2016	RESNET		CAC and HP EERE 2016			
SSER2	RESNET						CAC and HP EERE 2016	ENERGY STAR V. 6.1	RESNET			
Average Life (y)	CAC and HP EERE 2016											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)	CAC and HP EERE 2016 / Less (2021)											
Annual Maintenance Cost (2022$)	CAC and HP EERE 2016											

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Residential Room Air Conditioners

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.2	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Distributors		RAC EERE 2022 NOPR									
CEER (Btu/Wh)	Guidehouse		CFR	DOE CCD	ENERGY STAR V. 4.2	DOE CCD	Guidehouse					
Average Life (y)	RAC EERE 2011	RAC EERE 2022 NOPR										
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Portable Air Conditioners

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SOURCES	2015	2020	2022		2025		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	New Standard	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	PAC EERE 2020/Guidehouse						Guidehouse					
CEER												
Average Life (y)												
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Swamp Coolers

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
CFM	Product Literature / Guidehouse				Guidehouse					
Power (Hp)										
Average Life (y)	TLC Plumbing / Guidehouse									
Retail Equipment Cost (2022$)	Product Literature / Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse									
Total Installed Cost (2022$)										
Annual Maintenance Cost (2022$)										

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Residential Air-Source Heat Pumps

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SOURCES	2015	2020	2022				2023				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.0	High	New Standard	ENERGY STAR V. 6.1	ENERGY STAR Cold Climate Criteria	High	Typical/High		
Typical Capacity (kBtu/h)	CACs and HPs EERE 2016 Direct Final Rule												
SEER (Cooling)	CACs and HPs EERE 2016 Direct Final Rule/ Guidehouse		CFR	DOE CCD/ Guidehouse	ENERGY STAR V. 5.0	CACs and HPs EERE 2016 Direct Final Rule	CACs and HPs EERE 2016 Direct Final Rule/ Guidehouse	ENERGY STAR V. 6.1	ENERGY STAR V. 6.1	CACs and HPs EERE 2016 Direct Final Rule	CACs and HPs EERE 2016 Direct Final Rule/Guidehouse		
HSPF (Heating)													
Average Life (y)	CACs and HPs EERE 2016 Direct Final Rule										Guidehouse		
Retail Equipment Cost (2022$)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													

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Residential Ductless Mini-Split Air-Source Heat Pumps

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	AHRI/Guidehouse				Guidehouse					
SEER										
EER										
HSPF										
Average Life (y)	CACs and HPs EERE 2016 Direct Final Rule									
Retail Equipment Cost (2022$)	Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse									
Total Installed Cost (2022$)										
Annual Maintenance Cost (2022$)	CACs and HPs EERE 2016 Direct Final Rule									

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Residential Ground-Source Heat Pumps

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.2	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Water-Source Unitary Heat Pumps EERE 2015 Final Rule / DOE CCD		Guidehouse									
COP (Heating)	AHRI Database	AHRI Database / DOE CCD										
EER (Cooling)												
Average Life (y)	Guidehouse / Water-Source Unitary Heat Pumps EERE 2015 Final Rule											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Natural Gas Heat Pumps

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SOURCES	2015	2020	2022	2030	2040	2050
	Installed Base		Typical			
Typical Capacity (kBtu/h)	Manufacturer		Guidehouse			
COP (Heating)	Product Literature					
COP (Cooling)						
Annual Electric Use (kWh/y)						
Average Life (y)	Guidehouse					
Retail Equipment Cost (2022$)	PERC					
Total Installed Cost (2022$)	Guidehouse					
Annual Maintenance Cost (2022$)						

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Residential Cordwood Stoves

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Distributors / Product Literature				Guidehouse					
Efficiency (Non-Catalytic) (HHV)	Guidehouse / Literature	EPA Certified Wood Stove Database (Room Heaters)								
Efficiency (Catalytic) (HHV)										
Average Life (y)	Guidehouse									
Retail Equipment Cost (2022$)	Product Literature/Dealers									
Total Installed Cost (2022$)	Dealers	Dealers/Guidehouse								
Annual Maintenance Cost (2022$)	Dealers/Guidehouse									

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Residential Wood Pellet Stoves

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SOURCES	2015	2020	2022		2030		2040		2050	
	Installed Base	Installed Base	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Distributors / Product Literature				Guidehouse					
Efficiency (HHV)	EPA Default/ Literature/ Guidehouse	EPA Certified Wood Stove Database (Room Heaters)								
Average Life (y)	Guidehouse									
Retail Equipment Cost (2022$)	Product Literature/ Dealers									
Total Installed Cost (2022$)	Dealers/Guidehouse									
Annual Maintenance Cost (2022$)										

Residential Water Heating

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Residential Gas-Fired Storage Water Heaters

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SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	Guidehouse	CWH EERE 2010 Final Rule /AHRI	CWH EERE 2022 Preliminary Analysis					Guidehouse					
Uniform Energy Factor		DOE CCD	CWH EERE 2022 Preliminary Analysis		ENERGY STAR	CWH EERE 2022 Preliminary Analysis	ENERGY STAR						
Average Life (y)	CWH EERE 2010 Final Rule		CWH EERE 2022 Preliminary Analysis										
Retail Equipment Cost (2022$)	Distributors	CWH EERE 2010 Final Rule											
Total Installed Cost (2022$)	EIA Technology Forecast Updates (2018)	CWH EERE 2010 Final Rule											
Annual Maintenance Cost (2022$)	CWH EERE 2010 Final Rule												

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Residential Oil-Fired Water Heaters

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SOURCES	2015	2020	2022			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	Typical / High		
Typical Capacity (gal)	AHRI	CWH EERE 2010 Final Rule/AHRI	CWH EERE 2022 Preliminary Analysis			Guidehouse		
Uniform Energy Factor	Guidehouse	AHRI/DOE CCD						
Average Life (y)	CWH EERE 2010 Final Rule							
Retail Equipment Cost (2022$)								
Total Installed Cost (2022$)								
Annual Maintenance Cost (2022$)								

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Residential Electric Resistance Storage Water Heaters

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SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	AHRI	CWH EERE 2010 Final Rule/AHRI	CWH EERE 2022 Preliminary Analysis			Guidehouse					
Uniform Energy Factor	Guidehouse	AHRI/ DOE CCD									
Average Life (y)	CWH EERE 2010 Final Rule										
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Annual Maintenance Cost (2022$)											

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Residential Heat Pump Water Heaters

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SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (gal)	Guidehouse	AHRI	CWH EERE 2022 Preliminary Analysis			Guidehouse					
Uniform Energy Factor		DOE CCD	CWH EERE 2022 Preliminary Analysis	ENERGY STAR	CWH EERE 2022 Preliminary Analysis						
Average Life (y)	CWH EERE 2010 Final Rule		CWH EERE 2022 Preliminary Analysis								
Retail Equipment Cost (2022$)	CWH EERE 2010 Final Rule	Distributors									
Total Installed Cost (2022$)	CWH EERE 2010 Final Rule										
Annual Maintenance Cost (2022$)											

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Residential Solar Water Heaters

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	ENERGY STAR V. 4.0	Typical	Typical	Typical	Typical
Typical Capacity (sq. ft.)	SRCC / Guidehouse		ENERGY STAR		Guidehouse		
Solar Uniform Energy Factor (SUEF)			DOE				
Average Life (y)	DOE / Guidehouse						
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023				
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse		DOE				

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Residential Gas-Fired Instantaneous Water Heaters

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SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 4.0	High	ENERGY STAR V. 5.0	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	AHRI	CWH EERE 2010 Final Rule /AHRI	CWH EERE 2022 Preliminary Analysis					Guidehouse					
Uniform Energy Factor	Guidehouse	DOE CCD	CWH EERE 2022 Preliminary Analysis		ENERGY STAR	CWH EERE 2022 Preliminary Analysis	ENERGY STAR						
Average Life (y)	CWH EERE 2010 Final Rule		CWH EERE 2022 Preliminary Analysis										
Retail Equipment Cost (2022$)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													

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Residential Electric Instantaneous Water Heaters

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SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	Guidehouse		CWH EERE 2022 Preliminary Analysis			Guidehouse					
Uniform Energy Factor			CWH EERE 2022 Preliminary Analysis/DOE CCD								
Average Life (y)			Gordian's RSMeans Data – Building Construction Costs 2023								
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Annual Maintenance Cost (2022$)			Guidehouse								

Residential Appliances

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Residential Refrigerator-Freezers (Top)

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse	RF EERE 2021 Preliminary Analysis / Guidehouse					Guidehouse					
Energy Consumption (kWh/y)		DOE CCD/ Guidehouse	CFR	DOE CCD	ENERGY STAR	DOE CCD						
Average Life (y)		RF EERE 2021 Preliminary Analysis / Guidehouse										
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Refrigerator-Freezers (Side)

Final

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse	RF EERE 2021 Preliminary Analysis / Guidehouse					Guidehouse					
Energy Consumption (kWh/y)		DOE CCD/ Guidehouse	CFR	DOE CCD	ENERGY STAR	DOE CCD						
Average Life (y)		RF EERE 2021 Preliminary Analysis / Guidehouse										
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Refrigerator-Freezers (Bottom)

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SOURCES	2015	2020	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical	High	Typical	High	Typical	High
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse	RF EERE 2021 Preliminary Analysis / Guidehouse					Guidehouse					
Energy Consumption (kWh/y)		DOE CCD/ Guidehouse	CFR	DOE CCD	ENERGY STAR	DOE CCD						
Average Life (y)		RF EERE 2021 Preliminary Analysis / Guidehouse										
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Annual Maintenance Cost (2022$)												

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Residential Freezers (Chest)

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SOURCES	2015	2020	2022			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	Typical / High		
Typical Capacity (ft^3)	RF EERE 2011 / Guidehouse		RF EERE Preliminary Analysis 2021/DOE CCD			Guidehouse		
Energy Consumption (kWh/y)	Guidehouse		RF EERE Preliminary Analysis 2021	RF EERE Preliminary Analysis 2021/DOE CCD	DOE CCD			
Average Life (y)	RF EERE 2011 / Guidehouse		RF EERE Preliminary Analysis 2021		RF EERE Preliminary Analysis 2021			
Retail Equipment Cost (2022$)					RF EERE Preliminary Analysis 2021/DOE CCD			
Total Installed Cost (2022$)								
Annual Maintenance Cost (2022$)								

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Residential Freezers (Upright)

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SOURCES	2015	2022	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 5.1	High	Typical / High		
Typical Capacity (ft^3)	RF EERE 2011/ Guidehouse		RF EERE Preliminary Analysis 2021/ DOE CCD				Guidehouse		
Energy Consumption (kWh/y)	Guidehouse		RF EERE Preliminary Analysis 2021	RF EERE Preliminary Analysis 2021/ DOE CCD	ENERGY STAR	DOE CCD			
Average Life (y)	RF EERE 2011 / Guidehouse		RF EERE Preliminary Analysis 2021			RF EERE Preliminary Analysis 2021			
Retail Equipment Cost (2022$)						RF EERE Preliminary Analysis 2021/ DOE CCD			
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)									

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Residential Natural Gas Cooktops

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (kBtu/h)	Distributors / Product Literature				Guidehouse		
Integrated Annual Energy Consumption (kBtu/y)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						
Cooking Efficiency (%)	Guidehouse						
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2016 SNOPR / Consumer Cooking Products EERE 2020 NOPD						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Natural Gas Ovens

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (kBtu/h)	Consumer Cooking Products EERE 2016 SNOPR / Product Literature				Guidehouse		
Typical Cavity Volume (ft^3)	Consumer Cooking Products EERE 2016 SNOPR	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kBtu/y)							
Cooking Efficiency (%)	Guidehouse						
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD	Consumer Cooking Products EERE 2020 NOPD					
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2016 SNOPR						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Natural Gas Ranges

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity of Cooktop Component (kBtu/h)	Distributors / Product Literature				Guidehouse		
Typical Capacity of Oven Component (kBtu/h)	Consumer Cooking Products EERE 2016 SNOPR / Product Literature						
Typical Cavity Volume of Oven Component (ft^3)	Consumer Cooking Products EERE 2020 NOPD	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kBtu/y)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Guidehouse / Distributors / Gordian's RSMeans Data – Building Construction Costs 2023						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Cooktops

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (W)	Consumer Cooking Products EERE 2016 SNOPR / Distributors				Guidehouse		
Integrated Annual Energy Consumption (kWh/y)	Consumer Cooking Products EERE 2020 NOPD						
Average Life (y)							
Retail Equipment Cost (2022$)							
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Ovens

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity (W)	Consumer Cooking Products EERE 2016 SNOPR / Distributors				Guidehouse		
Typical Cavity Volume (ft^3)	Consumer Cooking Products EERE 2016 SNOPR	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kWh/y)							
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2020 NOPD						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Ranges

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SOURCES	2015	2020	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	High	Typical / High		
Typical Capacity of Cooktop Component (W)	Consumer Cooking Products EERE 2016 SNOPR / Distributors				Guidehouse		
Typical Capacity of Oven Component (W)							
Typical Cavity Volume of Oven Component (ft^3)	Consumer Cooking Products EERE 2016 SNOPR	Consumer Cooking Products EERE 2020 NOPD					
Integrated Annual Energy Consumption (kWh/y)							
Average Life (y)	Consumer Cooking Products EERE 2020 NOPD						
Retail Equipment Cost (2022$)	Consumer Cooking Products EERE 2020 NOPD						
Total Installed Cost (2022$)							
Annual Maintenance Cost (2022$)	Guidehouse / Consumer Cooking Products EERE 2016 SNOPR						

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Residential Electric Clothes Dryers

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SOURCES	2015	2020	2022				2030	2040	2040
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1	High	Typical / High		
Typical Capacity (ft^3)	DOE CCD					Guidehouse / DOE CCD / ENERGY STAR	Guidehouse		
CEF, D1 (lb/kWh)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse	DOE CCD	Consumer Clothes Dryers EERE 2022 NOPR	DOE CCD	ENERGY STAR V. 1.1	DOE CCD			
CEF, D2 (lb/kWh)						ENERGY STAR			
Average Life (y)	Consumer Clothes Dryers EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse								
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR								

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Residential Natural Gas Clothes Dryers

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 1.1	High	Typical / High		
Typical Capacity (ft^3)	DOE CCD						Guidehouse		
CEF, D1 (lb/kWh)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse	DOE CCD	Consumer Clothes Dryers EERE 2022 NOPR	DOE CCD	ENERGY STAR V. 1.1	DOE CCD			
CEF2, D2 (lb/kWh)									
Average Life (y)	Consumer Clothes Dryers EERE 2022 NOPR								
Retail Equipment Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR / Guidehouse								
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)	Consumer Clothes Dryers EERE 2022 NOPR								

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Residential Clothes Washers (Front)

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical / High		
Typical Capacity (ft^3)	Guidehouse	DOE CCD / Guidehouse	DOE CCD	DOE CCD	DOE CCD	DOE CCD	Guidehouse		
Integrated Modified Energy Factor (ft^3/kWh/cycle)	AHAM / Guidehouse		RCW EERE 2021 Preliminary Analysis		ENERGY STAR V. 8.1				
Integrated Water Factor (gal/cycle/ft^3)									
Average Life (y)	RCW EERE 2021 Preliminary Analysis								
Water Consumption (gal/cycle)	Guidehouse / RCW EERE 2021 Preliminary Analysis								
Hot Water Energy (kWh/cycle)									
Machine Energy (kWh/cycle)									
Dryer Energy (kWh/cycle)									
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)	RCW EERE 2021 Preliminary Analysis/ Distributors							
Total Installed Cost (2022$)		RCW EERE 2021 Preliminary Analysis/ Guidehouse							
Annual Maintenance Cost (2022$)	RCW EERE 2021 Preliminary Analysis / Guidehouse								

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Residential Clothes Washers (Top)

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SOURCES	2015	2020	2022				2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 8.1	High	Typical / High		
Typical Capacity (ft^3)	Guidehouse	Guidehouse	DOE CCD	DOE CCD	DOE CCD	DOE CCD	Guidehouse		
Integrated Modified Energy Factor (ft^3/kWh/cycle)	AHAM / Guidehouse	RCW EERE 2021 Preliminary Analysis			ENERGY STAR V. 8.1	DOE CCD			
Integrated Water Factor (gal/cycle/ft^3)									
Average Life (y)	RCW EERE 2021 Preliminary Analysis								
Water Consumption (gal/cycle)	RCW EERE 2021 Preliminary Analysis / Guidehouse								
Hot Water Energy (kWh/cycle)	Guidehouse	RCW EERE 2021 Preliminary Analysis / Guidehouse							
Machine Energy (kWh/cycle)									
Dryer Energy (kWh/cycle)									
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)								
Total Installed Cost (2022$)									
Annual Maintenance Cost (2022$)	RCW EERE 2021 Preliminary Analysis / Guidehouse								

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Residential Dishwashers

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SOURCES	2015	2020	2022				2023	2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 6.0	High	ENERGY STAR V. 7.0	Typical / High		
Typical Annual Energy Use (kWh/y)	AHAM 2014 / DW EERE 2012 Final Rule	Guidehouse / DOE CCD / ENERGY STAR	CFR	Guidehouse / DOE CCD / ENERGY STAR	ENERGY STAR	DW EERE 2022 Preliminary Analysis	ENERGY STAR	Guidehouse		
Water Consumption (gal/cycle)										
Water Heating Energy Use (kWh/y)	AHAM 2014 / DW EERE 2012 Final Rule	DW EERE 2016 Direct Final Rule	DW EERE 2022 Preliminary Analysis							
Average Life (y)	DW EERE 2016 Direct Final Rule/Guidehouse									
Retail Equipment Cost (2022$)	DW EERE 2012 Final Rule	DW EERE 2016 Direct Final Rule								
Total Installed Cost (2022$)										

Commercial Space Heating and Cooling

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Commercial Gas-Fired Furnaces

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SOURCES	2012	2018	2022			2023			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	High	Typical/High		
Typical Input Capacity (kBtu/h)	AHRI	CWAF EERE 2015	DOE CCD						Guidehouse		
Thermal Efficiency (%)		DOE CCD	CFR	DOE CCD		CFR					
Typical Output Capacity (kBtu/h)	Guidehouse										
Average Life (y)	CWAF EERE 2015										
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$)											
Annual Maintenance Cost (2022$/kBtu/h)											

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Commercial Oil-Fired Furnaces

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SOURCES	2012	2018	2022			2023		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	Typical/High		
Typical Input Capacity (kBtu/h)	AHRI	DOE CCD	DOE CCD					Guidehouse		
Thermal Efficiency (%)			10 CFR 431.77	DOE CCD		10 CFR 431.77				
Typical Output Capacity (kBtu/h)	Guidehouse									
Average Life (y)	CWAF EERE 2015									
Retail Equipment Cost (2022$)										
Total Installed Cost (2022$)										
Total Installed Cost (2022$/kBtu/h)										
Annual Maintenance Cost (2022$)										
Annual Maintenance Cost (2022$/kBtu/h)										

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Commercial Electric Resistance Heaters

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SOURCES	2012		2018		2022		2030		2040		2050	
	Small	Large	Small	Large	Small	Large	Small	Large	Small	Large	Small	Large
Typical Capacity (kBtu/h)	Distributors/Guidehouse						Guidehouse					
Efficiency (%)	Guidehouse/DOE											
Average Life (y)	Technology Cost and Performance File for Commercial Model for AEO2010											
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)				Gordian's RSMeans Data – Building Construction Costs 2023							
Total Installed Cost (2022$)												
Total Installed Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$)	Guidehouse											
Annual Maintenance Cost (2022$/kBtu/h)												

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Commercial Electric Boilers

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SOURCES	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical			
Typical Capacity (kW)	BSRIA		Guidehouse			
Efficiency (%)	EERE / Guidehouse					
Average Life (y)	ASHRAE 2007 HVAC Applications	ASHRAE 2015 HVAC Applications	ASHRAE 2019 HVAC Applications			
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse			
Total Installed Cost (2022$)			Gordian's RSMeans Data – Building Construction Costs 2023			
Total Installed Cost (2022$/kBtu/h)						
Annual Maintenance Cost (2022$)			EIA Technology Forecast Updates (2018)			
Annual Maintenance Cost (2022$/kBtu/h)						

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Commercial Gas-Fired Boilers

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SOURCES	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	Guidehouse	Comm. Packaged Boilers EERE 2020												
Thermal Efficiency (%)	ASHRAE Standard 90.1-2004 / Guidehouse	Comm. Packaged Boilers EERE 2020 / Guidehouse	DOE CCD			Comm. Packaged Boilers EERE 2020/Guidehouse								
Average Life (y)	Comm. Heating, AC, WH EERE 2009	Comm. Packaged Boilers EERE 2020												
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)													
Total Installed Cost (2022$)														
Total Installed Cost (2022$/kBtu/h)														
Annual Maintenance Cost (2022$)	Comm. Heating, AC, WH EERE 2009													
Annual Maintenance Cost (2022$/kBtu/h)														

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Commercial Oil-Fired Boilers

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SOURCES	2012	2018	2022			2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	New Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Input Capacity (kBtu/h)	Guidehouse	Comm. Packaged Boilers EERE 2020												
Thermal Efficiency (%)	ASHRAE Standard 90.1-2004 / Guidehouse	Comm. Packaged Boilers EERE 2020 / Guidehouse	DOE CCD			Comm. Packaged Boilers EERE 2020/Guidehouse								
Average Life (y)	Comm. Heating, AC, WH EERE 2009	Comm. Packaged Boilers EERE 2020												
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)													
Total Installed Cost (2022$)														
Total Installed Cost (2022$/kBtu/h)														
Annual Maintenance Cost (2022$)	Comm. Heating, AC, WH EERE 2009													
Annual Maintenance Cost (2022$/kBtu/h)														

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Commercial Centrifugal Chillers (Water-Cooled)

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	IPCC/ARB/TEAP/Guidehouse					Guidehouse					
Efficiency (kW/ton)	ASHRAE 90.1-2010/FEMP/ eSource/ Product Literature	ASHRAE 90.1-2019/Product Lit									
COP											
Average Life (y)	2007 ASHRAE Applications Handbook	2015 ASHRAE Applications Handbook A37 Table 4									
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)	Gordian's RSMeans Data – Building Construction Costs 2023									
Total Installed Cost (2022$/ton)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power										
Annual Maitnenance Cost (2022$/kBtu/h)											

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Commercial Reciprocating Chillers (Air-Cooled Only)

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (tons)	BSRIA/DEER		Guidehouse			Guidehouse					
Efficiency (kW/ton)	ASHRAE 90.1-2010/DEER/ FEMP/Product Literature	ASHRAE 90.1-2016 (>150 TR)	ASHRAE 90.1-2019		Product Lit						
COP	ASHRAE 90.1-2010/DEER/ FEMP/Product Literature	ASHRAE 90.1-2016 (>150 TR)									
Average Life (y)	Manufacturers	2015 ASHRAE Applications Handbook A37 Table 4									
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023								
Total Installed Cost (2022$/ton)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power										
Annual Maintenance Cost (2022$/kBtu/h)											

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Commercial Screw Chillers (Air-Cooled Only)

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SOURCES	2012	2018	2022			2030	2040	2050
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical/High		
Typical Capacity (tons)	Guidehouse					Guidehouse		
Efficiency (kW/ton)	Guidehouse	ASHRAE 90.1-2016 (>150 TR)	ASHRAE 90.1-2019 (>150 TR)	ASHRAE 90.1-2019 (>150 TR)/Product Lit	Product Lit			
COP								
Average Life (y)	Manufacturers	FacilitiesNet						
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$/ton)								
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Scroll Chillers (Air-Cooled Only)

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SOURCE	2012	2018	2022			2030	2040	2050
	Installed Base	Installed Base	ASHRAE 90.1-2019	Typical	High	Typical / High		
Typical Capacity (tons)	Guidehouse/Manufacturers					Guidehouse		
Efficiency [full-load/IPLV] (kW/ton)	Guidehouse	Product Lit/ Guidehouse	ASHRAE 90.1-2019 (>150 TR)	Product Lit/ Guidehouse	Product Lit			
COP [full-load/IPLV]								
Average Life (y)	Manufacturers							
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$/ton)								
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Gas-Fired Chillers (Water-Cooled, Direct-Fired Only)

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SOURCES	2012		2018		2022				2030	2040	2050
	Installed Base: Absorption	Installed Base: Engine-Driven	Installed Base: Absorption	Installed Base: Engine-Driven	ASHRAE 90.1-2019 Absorption	CA Title 24 – Engine-Driven	Absorption	Engine-Driven	Absorption/Engine-Driven		
Typical Capacity (tons)	BSRIA/Distributors								Guidehouse		
COP [full-load]	Product Literature/ Guidehouse		Product Lit		ASHRAE 90.1-2019 Direct-fired Double Effect	CA Title 24 Gas Engine Standard	Product Lit				
COP [IPLV]											
Average Life (y)	2007 ASHRAE Applications Handbook/ Distributors		2015 ASHRAE Applications Handbook A37 Table 4								
Retail Equipment Cost (2022$/ton)	EIA Technology Forecast Updates (2018)				Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse						
Total Installed Cost (2022$/ton)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$/ton)	Guidehouse/Alabama Power										
Annual Maintenance Cost (2022$/kBtu/h)											

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Commercial Rooftop Air Conditioners

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SOURCES	2012	2018	2022				2023				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	Typical	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Output Capacity (kBtu/h)	AHRI / Guidehouse	CUAC EERE 2016									CUAC EERE 2016 / Guidehouse					
Part Load Efficiency (IEER)	CUAC EERE 2016				ENERGY STAR	CUAC EERE 2016			ENERGY STAR	CUAC EERE 2016						
Efficiency (EER)	CUAC EERE 2016 / Guidehouse															
Efficiency Conversion	Calculated															
Average Life (y)	CUAC EERE 2016															
Retail Equipment Cost (2022$)	Distributors / Guidehouse / DEER, 2008	CUAC EERE 2016														
Total Installed Cost (2022$)																
Total Installed Cost (2022$/kBtu/h)	Calculated															
Annual Maintenance Cost (2022$)	CUAC EERE 2016															
Annual Maintenance Cost (2022$/kBtu/h)	Calculated															

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Commercial Gas-Fired Engine-Drive Rooftop Air Conditioners

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SOURCES	2012	2018	2022	2030	2040	2050
	Installed Base		Typical			
Typical Capacity (tons)	EIA Technology Forecast Updates (2018)		Guidehouse			
Heating COP						
Cooling COP						
Average Life (y)						
Retail Equipment Cost ($/ton)			Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse			
Total Installed Cost ($/ton)						
Total Installed Cost ($/kBtu/h)						
Annual Maintenance Cost (2022$)						
Annual Maintenance Cost (2022$/kBtu/h)						

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Commercial Rooftop Heat Pumps

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SOURCES	2012	2018	2022				2023			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 3.1	High	New Standard	ENERGY STAR V. 4.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	CUHP EERE 2016									CUHP EERE 2016 / Guidehouse					
Part Load Efficiency (IEER)	CUHP EERE 2016 / Guidehouse				ENERGY STAR	CUHP EERE 2016		ENERGY STAR	CUHP EERE 2016						
COP (Heating)															
Average Life (y)	EIA Technology Forecast Updates (2018)		CUHP EERE 2016												
Retail Equipment Cost (2022$)															
Total Installed Cost (2022$)															
Total Installed Cost (2022$/kBtu/h)															
Annual Maintenance Cost (2022$)															
Annual Maintenance Cost (2022$/kBtu/h)															

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Commercial Ground-Source Heat Pumps

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	U.S. DOE/EIA	Water-Source Unitary Heat Pumps EERE 2015 Final Rule				Guidehouse					
COP (Heating)	Guidehouse	AHRI Database									
EER (Cooling)											
Average Life (y)	Guidehouse / Water-Source Unitary Heat Pumps EERE 2015 Final Rule										
Retail Equipment Cost (2022$)	Distributors/Guidehouse	Water-Source Unitary Heat Pumps 2015 EERE Final Rule / Guidehouse									
Total Installed Cost (2022$)	U.S. DOD/IGSHPA/MA DOER/CEFIA/ ASHRAE										
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$)	Geothermal Heat Pump Consortium, Inc. (U.S. DOE Contract DE-FG07-95ID13347)										
Annual Maintenance Cost (2022$/kBtu/h)											

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Packaged Terminal Air Conditioners

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	PTAC & PTHP EERE 2022 NOPD					PTAC & PTHP EERE 2022 NOPD / Guidehouse					
Efficiency (EER)											
Efficiency											
Average Life (y)											
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$)											
Annual Maintenance Cost (2022$/kBtu/h)											

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Packaged Terminal Heat Pumps

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SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	PTAC & PTHP EERE 2022 NOPD					PTAC & PTHP EERE 2022 NOPD / Guidehouse					
Efficiency (EER)											
Efficiency											
COP (Heating)											
Average Life (y)											
Retail Equipment Cost (2022$)											
Total Installed Cost (2022$)											
Total Installed Cost (2022$/kBtu/h)											
Annual Maintenance Cost (2022$)											
Annual Maintenance Cost (2022$/kBtu/h)											

Commercial Water Heating

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Commercial Gas-Fired Storage Water Heaters

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SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Typical Storage Capacity (gal)	EIA Technology Forecast Updates (2018)	CWH EERE 2022 NOPR										
Typical Input Capacity (kBtu/h)												
Thermal Efficiency (%)		DOE CCD / Guidehouse	CFR	DOE CCD / Guidehouse	ENERGY STAR	DOE CCD	CWH EERE 2022 NOPR / Guidehouse					
Average Life (y)		CWH EERE 2022 NOPR										
Retail Equipment Cost (2022$)	CWH EERE 2022 NOPR											
Total Installed Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$)												
Annual Maintenance Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$/kBtu/h)												

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Commercial Electric Resistance Storage Water Heaters

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SOURCES	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical		
Typical Storage Capacity (gal)	Product Literature / Guidehouse	CWH EERE 2016 NOPR			Guidehouse		
Typical Input Capacity (kW)	Product Literature						
Typical Input Capacity (kBtu/h)							
Thermal Efficiency (%)	Guidehouse						
Average Life (y)	CWH EERE 2016 NOPR						
Retail Equipment Cost (2022$)	CWH EERE 2016 NOPR / Guidehouse	CWH EERE 2016 NOPR					
Total Installed Cost (2022$)							
Total Installed Cost (2022$/kBtu/h)							
Annual Maintenance Cost (2022$)							
Annual Maintenance Cost (2022$/kBtu/h)							

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Commercial Heat Pump Water Heaters

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SOURCES	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.0	Typical	Typical	Typical
Water Flow Rate (gal/min)	Distributors/Guidehouse		Guidehouse				
Typical Output Capacity (kW)							
Typical Output Capacity (kBtu/h)							
Coefficient of Performance (COP_h)							
Average Life (y)	EERE/Guidehouse						
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)						
Total Installed Cost (2022$)							
Total Installed Cost (2022$/kBtu/h)							
Annual Maintenance Cost (2022$)	Guidehouse						
Annual Maintenance Cost (2022$/kBtu/h)							

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Commercial Oil-Fired Storage Water Heaters

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Return to Table of Contents

SOURCES	2012	2018	2022			2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	High	Typical/High		
Typical Storage Capacity (gal)	AHRI / Guidehouse	DOE CCD/Guidehouse				Guidehouse		
Typical Input Capacity (kBtu/h)								
Thermal Efficiency (%)	Guidehouse		CFR	DOE CCD				
Average Life (y)	Commercial Heating, Air Conditioning and Water Heating Equipment EERE 2001							
Retail Equipment Cost (2022$)	Distributors / Guidehouse							
Total Installed Cost (2022$)								
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)								
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Electric Booster Water Heaters

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Return to Table of Contents

SOURCES	2012	2018	2022	2030	2040	2050
	Installed Base	Installed Base	Typical	Typical	Typical	Typical
Typical Capacity (gal)	Product Literature / Guidehouse					
Typical Output Capacity (kBtu/h)						
Thermal Efficiency (%)						
Average Life (y)						
Retail Equipment Cost (2022$)						
Total Installed Cost (2022$)						
Total Installed Cost (2022$/kBtu/h)						
Annual Maintenance Cost (2022$)						
Annual Maintenance Cost (2022$/kBtu/h)						

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Commercial Gas-Fired Booster Water Heaters

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Return to Table of Contents

SOURCES	2012	2018	2022		2030	2040	2050
	Installed Base	Installed Base	Current Standard	Typical	Typical	Typical	Typical
Typical Capacity (gal)	Product Literature / Guidehouse				Guidehouse		
Typical Output Capacity (kBtu/h)							
Thermal Efficiency (%)							
Average Life (y)							
Retail Equipment Cost (2022$)							
Total Installed Cost (2022$)							
Total Installed Cost (2022$/kBtu/h)							
Annual Maintenance Cost (2022$)							
Annual Maintenance Cost (2022$/kBtu/h)							

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Commercial Gas-Fired Instantaneous Water Heaters

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Return to Table of Contents

SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Base	Installed Base	Current Standard	Typical	ENERGY STAR V. 2.0	High	Typical	High	Typical	High	Typical	High
Typical Capacity (kBtu/h)	DOE CCD						DOE CCD / Guidehouse					
Thermal Efficiency (%)	Guidehouse/DOE CCD		DOE CCD		ENERGY STAR	DOE CCD						
Average Life (y)	CWH EERE 2022 NOPR											
Retail Equipment Cost (2022$)												
Total Installed Cost (2022$)												
Total Installed Cost (2022$/kBtu/h)												
Annual Maintenance Cost (2022$)												
Annual Maintenance Cost (2022$/kBtu/h)												

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Commercial Solar Water Heaters

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Return to Table of Contents

SOURCES	2012	2018	2022		2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 4.0	ENERGY STAR V. 5.0	Typical	Typical	Typical
Typical Capacity (sq. ft.)	SRCC / Guidehouse					Guidehouse		
Typical Capacity (m^2)								
Typical Capacity (Input) (kBtu/h) - North								
Typical Capacity (Input) (kBtu/h) - South								
Solar Uniform Energy Factor (SUEF)	ENERGY STAR / Guidehouse							
Average Life (y)	SRCC / Guidehouse							
Retail Equipment Cost (2022$)	EIA Technology Forecast Updates (2018)		Gordian's RSMeans Data – Building Construction Costs 2023 / Guidehouse					
Total Installed Cost (2022$)								
Total Installed Cost (2022$/kBtu/h) - North	Guidehouse							
Total Installed Cost (2022$/kBtu/h) - South								
Annual Maintenance Cost (2022$)	DOE / Guidehouse							
Annual Maintenance Cost (2022$/kBtu/h) - North								
Annual Maintenance Cost (2022$/kBtu/h) - South								

Commercial Cooking Products

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Commercial Natural Gas Range with Griddle and Oven

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Return to Table of Contents

SOURCES	2012	2018	2022			2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2	High	ENERGY STAR V. 3.0	Typical/High		
Griddle - Cooking Energy Efficiency (%)	Guidehouse	FSTC	ENERGY STAR / FSTC	ENERGY STAR	ENERGY STAR	NA	Guidehouse		
Oven - Cooking Energy Efficiency (%)						ENERGY STAR			
Range - Cooking Energy Efficiency (%)			FEMP / CEC	NA	FEMP / CEC	NA			
Combined Energy Efficiency (%)	Guidehouse / FSTC								
Griddle - Normalized Idle Energy Rate (Btu/h/ft^2)	Guidehouse	FSTC	ENERGY STAR / FSTC	ENERGY STAR	ENERGY STAR	NA			
Oven - Idle Energy Rate (Btu/h)	FEMP		ENERGY STAR			ENERGY STAR			
Range - Idle Energy Rate (Btu/h)	FSTC			NA	FSTC	NA			
Combined Idle Energy Rate (Btu/h)	Guidehouse / FSTC / Distributors								
Average Life (y)	FSTC								
Retail Equipment Cost (2022$)	Distributors								
Total Installed Cost (2022$)	FSTC / Guidehouse								
Total Installed Cost (2022$/kBtu/h)									
Annual Maintenance Cost (2022$)	FSTC								
Annual Maintenance Cost (2022$/kBtu/h)									

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Commercial Electric Range with Griddle and Oven

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Return to Table of Contents

SOURCES	2012	2018	2022			2023	2030	2040	2050
	Installed Base	Installed Base	Typical	ENERGY STAR V. 2.2	High	ENERGY STAR V. 3.0	Typical/High		
Griddle - Cooking Energy Efficiency (%)	Guidehouse	FSTC	FSTC / ENERGY STAR / Guidehouse	ENERGY STAR	ENERGY STAR	NA	Guidehouse		
Oven - Cooking Energy Efficiency (%)						ENERGY STAR			
Range - Cooking Energy Efficiency (%)				NA	CEC	NA			
Combined Energy Efficiency (%)	Guidehouse / FSTC								
Griddle - Normalized Idle Energy Rate (kW/ft^2)	Guidehouse	FSTC	FSTC / ENERGY STAR / Guidehouse	ENERGY STAR	ENERGY STAR	NA			
Oven - Idle Energy Rate (kW)						ENERGY STAR			
Range - Idle Energy Rate (kW)	NA								
Combined Idle Energy Rate (kW)	Guidehouse / FSTC / Distributors								
Average Life (y)	FSTC								
Retail Equipment Cost (2022$)	Distributors								
Total Installed Cost (2022$)	FSTC / Guidehouse								
Total Installed Cost (2022$/kBtu/h)									
Annual Maintenance Cost (2022$)	FSTC								
Annual Maintenance Cost (2022$/kBtu/h)									

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Commercial Hot Food Holding Cabinets – Small

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Return to Table of Contents

SOURCES	2012	2018	2022				2030	2040
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical/High	
Interior Volume (ft^3)	FEMP / ENERGY STAR						Guidehouse	
Maximum Idle Energy Rate (W)	CEE / Guidehouse	FEMP	ASAP	ASAP / ENERGY STAR	ENERGY STAR V. 2.0	FEMP / ENERGY STAR		
Annual Energy Use (kWh/y)	FEMP							
Average Life (y)								
Retail Equipment Cost (2022$)	Distributors / ENERGY STAR Savings Calculator / Guidehouse							
Total Installed Cost (2022$)	Guidehouse							
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)	FSTC							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Hot Food Holding Cabinets – Medium

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Return to Table of Contents

SOURCES	2012	2018	2022				2030	2040
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical/High	
Interior Volume (ft^3)	FEMP / ENERGY STAR						Guidehouse	
Maximum Idle Energy Rate (W)	CEE / Guidehouse	FEMP	ASAP	ASAP / ENERGY STAR	ENERGY STAR V. 2.0	FEMP / ENERGY STAR		
Annual Energy Use (kWh/y)	FEMP							
Average Life (y)								
Retail Equipment Cost (2022$)	Distributors / ENERGY STAR Savings Calculator / Guidehouse							
Total Installed Cost (2022$)	Guidehouse							
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)	FSTC							
Annual Maintenance Cost (2022$/kBtu/h)								

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Commercial Hot Food Holding Cabinets – Large

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Return to Table of Contents

SOURCES	2012	2018	2022				2030	2040
	Installed Base	Installed Base	State Standards	Typical	ENERGY STAR V. 2.0	High	Typical/High	
Interior Volume (ft^3)	FEMP / ENERGY STAR						Guidehouse	
Maximum Idle Energy Rate (W)	CEE / Guidehouse	FEMP	ASAP	ASAP / ENERGY STAR	ENERGY STAR V. 2.0	FEMP / ENERGY STAR		
Annual Energy Use (kWh/y)	FEMP							
Average Life (y)								
Retail Equipment Cost (2022$)	Distributors / ENERGY STAR Savings Calculator / Guidehouse							
Total Installed Cost (2022$)	Guidehouse							
Total Installed Cost (2022$/kBtu/h)								
Annual Maintenance Cost (2022$)	FSTC							
Annual Maintenance Cost (2022$/kBtu/h)								

Appendix B
References

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March 2023

APPENDIX C

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Final

EIA - Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case

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Objective

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The objective of this study is to develop baseline and projected performance and cost characteristics for residential and commercial end-use equipment.

- Examine 2012 and 2018 (commercial) and 2015 and 2020 (residential) baselines, as well as this year's baseline (2022).
  - Review literature, standards, installed base, contractor, and manufacturer information.
  - Provide a relative comparison and characterization of the cost and efficiency of a generic product.
- Forecast technology improvements that are projected to be available through 2050.
  - Review trends in standards, product enhancements, and research and development (R&D).
  - Project impact of product improvements and technology enhancement.

The performance and cost characterization of end-use equipment developed in this study will assist EIA in projecting national primary energy consumption.

Methodology

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Input from industry stakeholders, including government, R&D organizations, and manufacturers, was used to project product enhancements concerning equipment performance and cost attributes.

- Technology forecasting involves many uncertainties.
- Technology developments affect performance and cost forecasts.
- Varied sources ensure a balanced view of technology progress and the probable timing of commercial availability.

Definitions

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The following tables represent the current and projected efficiencies for residential and commercial building equipment ranging from the installed base in 2012 and 2018 (for commercial products) and 2015 and 2020 (for residential) to the highest efficiency equipment that is expected to be commercially available by 2050, assuming incremental adoption. Below are definitions for the terms used in characterizing the status of each technology.

- **Installed Stock Average**: the installed and *in use* equipment for that year. Represents the installed stock of equipment, but does *not* represent sales.
- **Current Standard**: the minimum efficiency (or maximum energy use) required (allowed) by current U.S. Department of Energy (DOE) standards, when applicable. For lighting, if no product exists at the standard efficiency level, a hypothetical wattage and lumen output is given for the standard's efficiency level.
- **ENERGY STAR®**: the minimum efficiency required (or maximum energy use allowed) to meet the ENERGY STAR® criteria, when applicable. Presented performance data represents certified products just meeting current ENERGY STAR specifications. For lighting, if no products exist at the ENERGY STAR efficiency level, a hypothetical wattage and lumen output is given for the ENERGY STAR efficiency level.
- **Low**: The minimum efficiency product or product mix available on the market. This rating typically reflects minimal compliance with DOE standards.
- **Typical**: the average, or typical, product being sold in the particular timeframe.
- **High**: the product with the highest efficiency available in the particular timeframe.
- **Lumens (lm):** the unit for luminous flux used in the SI unit system. This unit is used to indicate a light source's light output. All reported lumens are initial lumens. 1 kilolumen (klm) = 1,000 lumens.
- **Correlated Color Temperature (CCT)**: a specification of the color appearance of the light emitted by a lamp. Note: CCT is not a performance metric.
- **Color Rendering Index (CRI)**: a scale from 0 to 100 percent indicating how accurate a given light source is at rendering color when compared to a reference light source. The higher the CRI, the better the color rendering ability.
- **British thermal unit (Btu)**: a measure of the heat content of fuels or energy sources. It is the quantity of heat required to raise the temperature of one pound of liquid water by 1°F at the temperature that water has its greatest density (approximately 39 °F). 1 kBtu = 1,000 Btu.
- **Cubic Feet per Minute (CFM)**: a measure of airflow volume equal to the number of cubic feet of air flowing through a two-dimensional plane in one minute.
- **Not Available (N/A)**: data is not available where indicated.

Calculations

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The following metrics are commonly referred to throughout the tables to follow. Below are the calculations for each metric

— **Lighting**

- **System Wattage** = (Lamp Wattage * Ballast Factor) / Ballast Efficiency
- **System Lumens** = Lamp Lumens * Ballast Factor
- **Lamp Efficacy** = Lamp Lumens / Lamp Wattage
- **System Efficacy** = System Lumens / System Wattage
- **Lamp Cost ($/klm)** = Lamp Cost / (Lamp Lumens / 1,000)
- **Total Equipment Cost** = Lamp Cost + Fixture (including ballast) Cost
- **System Cost ($/klm)** = Total Equipment Cost / (System Lumens / 1,000). l/b/f denotes that the cost includes the luminaire, the ballast, and the fixture.
- **Total Installed Cost** = Total Equipment Cost + Labor Installation Cost
- **Ballast Luminous Efficiency (BLE)** = A/(1+B*Avg Total Lamp Arc Power^(-C)) where A, B, and C are pre-defined constants by DOE Energy Conservation Standards for Fluorescent Lamp Ballasts.

— **Commercial Refrigeration**

- **Nominal Capacity over Average Input (Btu in / Btu out)** = (Cooling or Heat Rejection Capacity)*24*365/(Annual Energy Consumption * 3,412)
- **Total Installed Cost** = Retail Equipment Cost + Labor Installation Cost
- **Total Installed Cost ($/kBtu/hour)** = Total Installed Cost*1,000 / (Cooling or Heat Rejection Capacity). h used as an abbreviation for hour throughout
- **Annual Maintenance Cost ($/kBtu/h)** = Annual Maintenance Cost * 1,000 / (Cooling or Heat Rejection Capacity)

— **Ventilation**

- **CFM out / Btu in / h** = System Airflow / (System Fan Power * 3,412)
- **Total Installed Cost ($/1,000 CFM)** = Total Installed Cost * 1,000 / System Airflow
- **Annual Maintenance Cost ($/1,000 CFM)** = Annual Maintenance Cost * 1,000 / System Fan Power

The market for the reviewed products has changed since this analysis was performed in 2015. These changes are noted and reflected in the efficiency and cost characteristics.

- DOE issued federal minimum efficiency standards that have gone into effect for General Service Fluorescent Lamps (2012), Incandescent Reflector Lamps (2012), and Fluorescent Lamp Ballasts (2019).

- In April 2022, DOE codified into the Code of Federal Regulations the 45 lumens per watt (lm/W) backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act (10 CFR 430, 87 FR 27439). This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

- DOE published a Final Rule updating energy conservation standards for Refrigerated Beverage Vending Machines at the end of 2015, effective in 2018. DOE also issued federal minimum efficiency standards that have or will soon go into effect for Refrigerated Beverage Vending Machines (2012), Automatic Commercial Ice Makers (2018), Walk-In Coolers and Freezers (2017), and Commercial Refrigeration Equipment (2017).

Residential Lighting

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Performance and Cost Characteristics » Residential General Service Lamps

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The residential general service lamps characterized in this report are a 60-watt and a 75-watt medium screw-based (E26) A-type incandescent lamp and their halogen, CFL, and LED equivalents. A standard 60-watt incandescent lamp produces approximately 800 – 850 lumens. A standard 75-watt incandescent lamp produces approximately 1,100 lumens.

Performance:

- A majority of residential lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Fixture prices and installation costs are not included for the residential sector. Labor costs are assumed to be negligible because homeowners likely replaces lamps themselves as they burn out. Therefore, total installed cost is the price of a lamp, and annual maintenance costs are the cost of replacing the lamps, which is a function of lamp life, lamp price, and the annual operating hours.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Legislation:

- The Energy Independence and Security Act of 2007 (EISA 2007) established standards for 60-watt general service lamps, effective in 2014, and 75-watt lamps, effective in 2013. These standards cannot be achieved by incandescent bulbs, but can be by halogen, CFL, and LED technologies.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps. These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

ENERGY STAR:

- For ENERGY STAR qualification, general service omnidirectional lamps must have a minimum lamp efficacy of 70 lm/W for products with CRI ≥ 90 and 80 lm/W for lamps with CRI < 90. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

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Performance and Cost Characteristics » Residential General Service Lamps

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Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent, halogen, and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050:

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022.
CFL	+0.5%	0%	-0.5%	Improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps.

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Performance and Cost Characteristics » Residential General Service Incandescent Lamps (60 W)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	60.0	60.0	N/A	N/A	N/A	N/A	18.9	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	850	850	N/A	N/A	N/A	N/A	850	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	14.2	14.2	N/A	N/A	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	1.0	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	511	511	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$0.30	$0.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$0.34	$0.34	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$0.30	$0.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$0.15	$0.15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$0.35	$0.35	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$0.18	$0.18	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 (EISA 2007) prescribes standards for 60 watt incandescent lamps as of January 1, 2014. Despite the phase out of incandescent lamps, these products remain in the installed stock.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards cannot be met with incandescent technologies.

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Performance and Cost Characteristics » Residential General Service Incandescent Lamps (75 W)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	75.0	75.0	N/A	N/A	N/A	N/A	26.0	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,170	1,170	N/A	N/A	N/A	N/A	1,170	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	15.6	15.6	N/A	N/A	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	0.8	0.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	511	511	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$0.44	$0.44	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$0.38	$0.38	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$0.44	$0.44	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$0.30	$0.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$0.38	$0.38	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$0.26	$0.26	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 (EISA 2007) prescribes standards for 75 watt incandescent lamps as of January 1, 2013. Despite the phase out of incandescent lamps, these products remain in the installed stock.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards cannot be met with incandescent technologies.

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Performance and Cost Characteristics » Residential General Service Halogen Lamps (60 W Incandescent Equivalent)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	43.1	43.1	N/A	43.0	N/A	N/A	16.7	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	750	750	N/A	750	N/A	N/A	750	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	17.4	17.4	N/A	17.4	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,850	N/A	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	1.0	1.0	N/A	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	621	621	N/A	621	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$2.36	$4.90	N/A	$5.92	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$3.15	$6.54	N/A	$7.89	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$2.36	$4.90	N/A	$5.92	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$1.47	$3.04	N/A	$3.68	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$3.15	$6.54	N/A	$7.89	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.95	$4.06	N/A	$4.90	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 (EISA 2007) prescribes standards for 60 watt incandescent lamps as of January 1, 2014. Starting in 2014, 60 watt incandescent lamps were replaced by halogen lamps.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards cannot be met with existing halogen lamp technologies.

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Performance and Cost Characteristics » Residential General Service Halogen Lamps (75 W Incandescent Equivalent)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	53.0	53.0	N/A	53.0	N/A	N/A	19.8	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,050	936	N/A	890	N/A	N/A	890	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	19.8	17.7	N/A	16.8	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,950	N/A	2,950	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	1.0	1.0	N/A	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	621	621	N/A	621	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$2.37	$3.58	N/A	$4.06	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$2.26	$3.82	N/A	$4.56	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$2.37	$3.58	N/A	$4.06	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$1.47	$2.22	N/A	$2.52	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$2.26	$3.82	N/A	$4.56	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.40	$2.37	N/A	$2.83	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 prescribes standards for current 75 watt incandescent lamps as of January 1, 2013. Starting in 2013, 75 watt incandescent lamps were replaced by halogen lamps.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards cannot be met with existing halogen lamp technologies.

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Performance and Cost Characteristics » Residential General Service Compact Fluorescent Lamps (60 W Incandescent Equivalent)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[4]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	13.0	13.1	14.0	13.0	13.0	13.8	20.0	12.5	12.5	11.9	11.9	11.3	11.3
Lamp Lumens	825	900	900	900	925	800	900	900	925	900	925	900	925
Lamp Efficacy (lm/W)[3]	63.5	68.5	64.3	69.2	71.2	80.0	45.0	72.0	74.1	75.7	77.8	79.6	81.8
CRI	82	82	82	82	82	80	N/A	82	82	82	82	82	82
Correlated Color Temperature (CCT)	2,700	2,700	2,700	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	10.0	10.0	10.0	10.0	12.0	10.0	N/A	10.0	12.0	10.0	12.0	10.0	12.0
Annual Operating Hours (h/y)	767	767	767	767	767	N/A	N/A	767	767	767	767	767	767
Lamp Price (2022$)	$2.55	$5.40	$1.50	$5.35	$4.63	N/A	N/A	$5.14	$4.45	$4.89	$4.23	$4.65	$4.02
Lamp Cost (2022$/klm)[3]	$3.10	$6.00	$1.67	$5.94	$5.01	N/A	N/A	$5.71	$4.81	$5.43	$4.57	$5.17	$4.35
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0	0	0	0	0	N/A	N/A	0	0	0	0	0	0
Total Installed Cost (2022$)	$2.55	$5.40	$1.50	$5.35	$4.63	N/A	N/A	$5.14	$4.45	$4.89	$4.23	$4.65	$4.02
Annual Maintenance Cost (2022$)	$0.20	$0.41	$0.12	$0.41	$0.30	N/A	N/A	$0.39	$0.28	$0.37	$0.27	$0.36	$0.26
Total Installed Cost (2022$/klm)	$3.09	$6.00	$1.67	$5.94	$5.01	N/A	N/A	$5.71	$4.81	$5.43	$4.57	$5.17	$4.35
Annual Maintenance Cost (2022$/klm)	$0.24	$0.46	$0.13	$0.46	$0.32	N/A	N/A	$0.44	$0.31	$0.42	$0.29	$0.40	$0.28

1. 2020 data back calculated based on 2022 data and the following assumptions: Efficacy +0.5%/y, Cost -0.5%/y (NCI, 2019)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards can be met with existing CFL products.
3. Year-to-year price and performance assumptions for incumbent technologies from 2022 to 2050: Efficacy +0.5%/y, Cost -0.5%/y (NCI, 2019)
4. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)

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Performance and Cost Characteristics » Residential General Service LED Lamps (60 W Incandescent Equivalent)

Final

DATA	2015	2020	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	8.7	9.2	10.0	8.9	8.0	10.0	17.8	7.3	6.6	5.8	5.2	5.0	4.5
Lamp Lumens	656	803	800	800	800	800	800	800	800	800	800	800	800
Lamp Efficacy (lm/W)	75.5	87.1	80.0	90.0	100.0	80.0	45.0	108.9	120.9	138.6	154.0	160.7	178.6
CRI	81	85	80	81	90	80	N/A	81	90	81	90	81	90
Correlated Color Temperature (CCT)	2,700	2,700	2,700	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	25	21	15	14	18	15.0	N/A	14	18	14	18	14	18
Annual Operating Hours (h/y)	657	657	657	657	657	657	N/A	657	657	657	657	657	657
Lamp Price (2022$)	$13.53	$4.56	$6.20	$3.92	$5.32	$6.20	N/A	$3.23	$4.39	$2.84	$3.86	$2.46	$3.33
Lamp Cost (2022$/klm)	$20.63	$5.68	$7.75	$4.90	$6.65	$7.75	N/A	$4.04	$5.49	$3.56	$4.83	$3.07	$4.17
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	0.0	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$13.53	$4.56	$6.20	$3.92	$5.32	$6.20	N/A	$3.23	$4.39	$2.84	$3.86	$2.46	$3.33
Annual Maintenance Cost (2022$)	$0.35	$0.15	$0.27	$0.18	$0.19	$0.27	N/A	$0.15	$0.16	$0.13	$0.14	$0.11	$0.12
Total Installed Cost (2022$/klm)	$20.63	$5.68	$7.75	$4.90	$6.65	$7.75	N/A	$4.04	$5.49	$3.56	$4.83	$3.07	$4.17
Annual Maintenance Cost (2022$/klm)	$0.54	$0.18	$0.34	$0.22	$0.24	$0.34	N/A	$0.18	$0.20	$0.16	$0.17	$0.14	$0.15

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

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Performance and Cost Characteristics » Residential General Service Filament-LED Lamps (60 W Incandescent Equivalent)

Final

DATA	2015	2020	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	9.7	7.1	5.5	6.9	8.0	13.8	17.8	7.0	6.6	5.5	5.2	4.7	4.5
Lamp Lumens	457	650	450	650	800	800	800	800	800	800	800	800	800
Lamp Efficacy (lm/W)	47.1	91.7	81.8	94.8	100.0	80.0	45.0	114.6	120.9	146.0	154.0	169.3	178.6
CRI	82	84	90	84	80	80	N/A	81	90	81	90	81	90
Correlated Color Temperature (CCT)	2,700	2,700	2,700	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	23	21	15	15	15	15	N/A	15	15	15	15	15	15
Annual Operating Hours (h/y)	657	657	657	657	657	N/A	N/A	657	657	657	657	657	657
Lamp Price (2022$)	$15.17	$6.88	$6.25	$5.91	$7.75	N/A	N/A	$4.87	$6.39	$4.29	$5.62	$3.70	$4.86
Lamp Cost (2022$/klm)	$33.20	$10.58	$13.89	$9.09	$9.69	N/A	N/A	$6.09	$7.99	$5.36	$7.03	$4.63	$6.07
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$15.17	$6.88	$6.25	$5.91	$7.75	N/A	N/A	$4.87	$6.39	$4.29	$5.62	$3.70	$4.86
Annual Maintenance Cost (2022$)	$0.43	$0.21	$0.27	$0.26	$0.34	N/A	N/A	$0.21	$0.28	$0.19	$0.25	$0.16	$0.21
Total Installed Cost (2022$/klm)	$33.20	$10.58	$13.89	$9.09	$9.69	N/A	N/A	$6.09	$7.99	$5.36	$7.03	$4.63	$6.07
Annual Maintenance Cost (2022$/klm)	$0.93	$0.33	$0.61	$0.40	$0.42	N/A	N/A	$0.27	$0.35	$0.23	$0.31	$0.20	$0.27

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

Performance and Cost Characteristics » Residential Reflector Lamps

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The residential reflector lamps characterized in this report are directional lamps that emit approximately 550 – 850 lumens (except for LED PAR38s which have outputs up to 1,700 lumens). Multiple baseline reflector lamps were analyzed, including 65W Incandescent BR30, Halogen PAR30, Halogen Infrared Reflector (HIR) PAR30, CFL BR30, LED BR30, and LED PAR38.

Performance:

- A majority of residential lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but for CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy.
- Fixture prices and installation costs are not included for the residential sector. Labor costs are assumed to be negligible because homeowners likely replaces lamps themselves as they burn out. Therefore, total installed cost is the price of a lamp, and annual maintenance costs are the cost of replacing the lamps, which is a function of lamp life, lamp price, and the annual operating hours.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Legislation:

- EPAct92 established minimum performance standards for some reflector lamps and provided exemptions for certain specialty applications (e.g., ER/BR, vibration service, more than 5% neodymium oxide, impact resistant, infrared heat, colored). EPAct92 effectively phased-out R-shaped tungsten filament incandescent reflector lamps at certain wattages and bulb diameters, replacing them with more efficient and cost effective tungsten-halogen parabolic aluminized reflector (PAR) lamps. EISA 2007 took away certain exemptions from EPACT 1992, requiring certain previously exempted lamps to meet EPAct92 minimum performance standards by January 1, 2008. The 65W BR30, a large majority of the incandescent reflector lamp market, was still exempted until 2022.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. **This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps.** These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

Performance and Cost Characteristics » Residential Reflector Lamps

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ENERGY STAR:

- For ENERGY STAR qualification, general service, reflector lamps must have a minimum lamp efficacy of 61 lm/W for products with CRI ≥ 90 and 70 lm/W for lamps with CRI < 90, respectively. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022.
CFL	+0.5%	0%	-0.5%	In addition to higher efficiency reflector coatings, improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Residential Reflector Lamps (65W BR30 Incandescent)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	65.0	65.0	N/A	65.0	N/A	N/A	13.3	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	637	637	N/A	602	N/A	N/A	600	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	9.8	9.8	N/A	9.3	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	2.0	2.0	N/A	2.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	621	621	N/A	621	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$4.00	$4.00	N/A	$3.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$6.28	$6.28	N/A	$6.15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$4.00	$4.00	N/A	$3.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$1.24	$1.24	N/A	$1.15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$6.28	$6.28	N/A	$6.15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.95	$1.95	N/A	$1.91	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. Incandescent BR30 lamps were previously exempted from DOE Incandescent Reflector Lamp standards and the EISA 2007 general service lamp definition until DOE's new final rule in 2022. The new definitions go into effect in 2023.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with incandescent technologies.

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Performance and Cost Characteristics » Residential Reflector Lamps (PAR30 Halogen)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	47.1	38.8	N/A	38.8	N/A	N/A	12.0	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	660	576	N/A	542	N/A	N/A	542	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	14.0	14.0	N/A	14.0	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,850	N/A	2,850	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	1.5	1.5	N/A	1.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	876	876	N/A	876	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$6.77	$8.13	N/A	$8.67	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$10.26	$14.12	N/A	$16.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$6.77	$8.13	N/A	$8.67	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$3.96	$4.75	N/A	$5.06	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$10.26	$14.12	N/A	$16.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$5.99	$8.25	N/A	$9.34	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. Halogen PAR30 lamps were previously exempted from the EISA 2007 GSL definition until DOE's new final rule in 2022. The new definitions go into effect in 2023. Note: product offerings are very limited in 2022.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with halogen technologies.

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Performance and Cost Characteristics » Residential Reflector Lamps (PAR30 Halogen Infrared Reflector (HIR))

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	38.9	45.5	N/A	48.0	N/A	N/A	18.7	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	650	786	N/A	840	N/A	N/A	840	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	16.7	17.3	N/A	17.5	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,850	N/A	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	4.0	4.0	N/A	4.2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	876	876	N/A	876	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$14.69	$25.62	N/A	$29.99	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$22.59	$32.60	N/A	$35.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$14.69	$25.62	N/A	$29.99	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$3.22	$5.61	N/A	$6.26	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$22.59	$32.60	N/A	$35.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$4.95	$7.14	N/A	$7.45	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. Halogen PAR30 lamps were previously exempted from the EISA 2007 GSL definition until DOE's new final rule in 2022. The new definitions go into effect in 2023. Note: product offerings are very limited in 2022.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with halogen technologies.

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Performance and Cost Characteristics » Residential Reflector Lamps (BR30 CFL)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[3]	2030[3]		2040[3]		2050[3]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[4]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	15.5	15.1	N/A	N/A	N/A	N/A	16.7	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	750	750	N/A	N/A	N/A	N/A	750	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	48.3	49.5	N/A	N/A	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	82	82	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	8.2	8.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	913	913	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$6.76	$6.59	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$9.01	$8.79	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$6.76	$6.59	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$0.75	$0.71	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$9.01	$8.79	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.00	$0.95	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. 2015 and 2020 data calculated based on 2009 installed stock data and the following assumptions: Efficacy +0.5%/y, Cost -0.5%/y (NCI, 2019)
2. Virtually all manufacturers have discontinued manufacturing of CFL reflector lamps in favor of LEDs. Distributor offerings for CFL reflectors have been eliminated.
3. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. Although these standards can be met with CFL technology, manufacturers have discontinued manufacturing CFL reflector lamps in favor of LEDs.
4. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)

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Performance and Cost Characteristics » Residential Reflector LED BR30

Final

DATA	2015	2020	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	14.2	10.9	11.0	8.8	7.2	10.7	14.4	7.1	6.2	6.2	5.4	5.5	4.8
Lamp Lumens	706	781	800	683	650	650	650	650	650	650	650	650	650
Lamp Efficacy (lm/W)	49.8	71.5	72.7	78.6	90.3	61.0	45.0	91.7	105.4	104.9	120.5	118.0	135.6
CRI	82	85	92	87	90	80	N/A	87	90	87	90	87	90
Correlated Color Temperature (CCT)	2,700	2,700	2,700	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	25	25	25	19	18	15	N/A	19	18	19	18	19	18
Annual Operating Hours (h/y)	730	730	730	730	730	N/A	N/A	730	730	730	730	730	730
Lamp Price (2022$)	$21.40	$15.36	$4.09	$5.01	$5.96	N/A	N/A	$4.11	$4.89	$3.62	$4.31	$3.14	$3.74
Lamp Cost (2022$/klm)	$30.31	$19.66	$5.11	$7.33	$9.17	N/A	N/A	$6.32	$7.53	$5.57	$6.64	$4.83	$5.75
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$21.40	$15.36	$4.09	$5.01	$5.96	N/A	N/A	$4.11	$4.89	$3.62	$4.31	$3.14	$3.74
Annual Maintenance Cost (2022$)	$0.63	$0.45	$0.12	$0.20	$0.24	N/A	N/A	$0.16	$0.19	$0.14	$0.17	$0.12	$0.15
Total Installed Cost (2022$/klm)	$30.31	$19.66	$5.11	$7.33	$9.17	N/A	N/A	$6.32	$7.53	$5.57	$6.64	$4.83	$5.75
Annual Maintenance Cost (2022$/klm)	$0.89	$0.57	$0.15	$0.29	$0.37	N/A	N/A	$0.25	$0.30	$0.22	$0.26	$0.19	$0.23

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. All LED lighting products exceed the new minimum efficacy standards.

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Performance and Cost Characteristics » Residential Reflector LED PAR38

Final

DATA	2015	2020	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	19.2	15.5	17.0	16.4	17.0	22.0	29.9	14.0	14.6	12.3	12.7	10.9	11.3
Lamp Lumens	1,202	1,211	1,200	1,344	1,700	1,344	1,344	1,344	1,700	1,344	1,700	1,344	1,700
Lamp Efficacy (lm/W)	62.7	77.9	70.6	82.0	100.0	61.0	45.0	95.7	116.7	109.5	133.5	123.2	150.2
CRI	83	86	82	86	82	80	N/A	86	86	86	86	86	86
Correlated Color Temperature (CCT)	3,000	3,000	2,700	3,000	3,000	3,000	N/A	3,000	3,000	3,000	3,000	3,000	3,000
Average Lamp Life (thousand hours)	24	27	25	27	25	15	N/A	27	25	27	25	27	25
Annual Operating Hours (h/y)	730	730	730	730	730	N/A	N/A	730	730	730	730	730	730
Lamp Price (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Lamp Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Annual Maintenance Cost (2022$)	$1.07	$0.60	$0.69	$0.62	$0.46	N/A	N/A	$0.52	$0.38	$0.46	$0.34	$0.41	$0.31
Total Installed Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Annual Maintenance Cost (2022$/klm)	$0.89	$0.49	$0.58	$0.46	$0.27	N/A	N/A	$0.39	$0.23	$0.35	$0.20	$0.31	$0.18

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. All LED lighting products exceed the new minimum efficacy standards.

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Performance and Cost Characteristics » Residential 4-foot Linear 2-Lamp Lighting Systems

Final

This section characterizes commercial linear fixtures that house two 4ft long linear lamps and their integrated luminaire equivalents. The technologies available for this system are linear fluorescent and LED.

- T5 lamps are approximately 40% narrower than T8 lamps and almost 60% narrower than T12 lamps. This narrowness allows T5 lamps to be coated with higher quality, more efficient phosphor blends than larger diameter lamps, resulting in a more efficacious lamp. The compact size of T5 lamps also permits greater flexibility in lighting design and construction.
- LED options for linear fixtures include replacement lamps that can fit directly into an existing fixture and fully integrated luminaires that can be used to replace existing fixtures. LED replacement lamps are also known as TLEDs. Type A TLEDs can be installed with existing ballasts and Type B and C TLEDs require the ballast to be disconnected. Replacement lamps are only sold to go into existing fixtures. If a new fixture is to be installed, a fully integrated LED luminaire is a more cost effective and efficient option. Because LED luminaires are fully integrated, they do not have lamp or fixture efficiency losses associated with ballasts and fixture optics.

Performance:

- Residential linear lamps often have a nominal CCT rating of 3,500K, but products with CCTs of 3,000K, 4,000K, and 4,100K (neutral white) are also common. 5,000K (daylight) lamps are available as well. When replacing a light bulb, it is important to choose a product with a similar CCT value to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but for CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps, which are sold only as a replacement for use in an existing fixture. The LED luminaire is more efficient and cost effective for new installations or fixture retrofits.
- Labor costs for lamp changes are assumed to be negligible because homeowners likely replace lamps themselves as they burn out. Therefore, annual maintenance costs are the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for residential linear systems.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Legislation:

- Beginning July 14, 2012 (or July 14, 2014, for T8 700-series phosphor lamps), DOE fluorescent lamp standards required a minimum efficacy of 89 lm/W. Although the amended performance-based standards do not explicitly prohibit T12 lamps, no T12 lamps met the standard at the time of its announcement. Since then, however, T12 lamps meeting the standard have entered the market.
- Beginning November 14, 2014, DOE standards required that the characterized residential ballasts have a minimum BLE = 0.993 / (1 + 0.41 * Avg Total Lamp Arc power ^ (- 0.25)). Residential ballasts also must have a minimum power factor of 0.5.
- California's Title 24 mandates the use of electronic ballasts with high efficacy luminaires (including fluorescent) of 13 W or higher (CEC, 2005).

ENERGY STAR:

- ENERGY STAR does not cover linear lamps. (ENERGY STAR, 2020)

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Performance and Cost Characteristics » Residential 4-foot Linear 2-Lamp Lighting Systems

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050:

Technology	Efficacy	Lifetime	Price	Potential for Improvements
T12	0%	0%	-0.5%	Limited because the technology is mature.
T8	0%	0%	-0.5%	Limited because the technology is mature.
T5	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Residential Linear Fluorescent Lamp T12

Final

DATA	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	40.0	40.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	2,860	2,860	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	72	72	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	70.0	82.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Lumens	3,890	5,148	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Efficacy (lm/W)	56	62	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Efficiency (BLE)	78%	87%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	70	70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	4,100	4,100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	15	15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	694	694	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$1.10	$1.10	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Price (2022$)	$13.31	$13.31	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$34.67	$34.67	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$0.38	$0.38	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (lamp, ballast, and fixture (l/b/f)) Cost (2022$/klm)	$12.90	$12.90	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor System Installation (hours)	0.5	0.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$39.71	$39.71	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$1.84	$1.84	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$10.21	$10.21	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$0.47	$0.47	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Note: Assume no labor is associated with lamp replacement in the residential sector because residents likely replace the lamps themselves.
Assume real cost has not changed since 2009 because this product has been phased out.

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Performance and Cost Characteristics » Residential Linear Fluorescent Lamp T8

Final

DATA	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	30.8	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
Lamp Lumens	2,770	2,855	2,450	2,855	3,100	2,855	3,100	2,855	3,100	2,855	3,100
Lamp Efficacy (lm/W)[1]	90	89	77	89	97	89	97	89	97	89	97
System Wattage	62.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1
System Lumens	4,875	5,082	4,361	5,082	5,518	5,082	5,518	5,082	5,518	5,082	5,518
System Efficacy (lm/W)	78	81	69	81	87	81	87	81	87	81	87
Ballast Efficiency (BLE)	87%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
CRI	85	87	90	87	85	87	85	87	85	87	85
Correlated Color Temperature (CCT)	4,100	4,100	5,000	4,100	3,500	4,100	3,500	4,100	3,500	4,100	3,500
Average Lamp Life (thousand hours)	21	31	23	31	40	31	40	31	40	31	40
Annual Operating Hours (h/y)	767	767	767	767	767	767	767	767	767	767	767
Lamp Price (2022$)	$6.54	$4.12	$3.36	$4.08	$4.32	$3.92	$4.15	$3.73	$3.95	$3.55	$3.75
Ballast Price (2022$)[2]	$19.10	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$29.23	$76.29	$75.53	$75.53	$75.53	$72.56	$72.56	$69.01	$69.01	$65.64	$65.64
Lamp Cost (2022$/klm)	$2.36	$1.44	$1.37	$1.43	$1.39	$1.37	$1.34	$1.31	$1.27	$1.24	$1.21
System (l/b/f) Cost (2022$/klm)	$12.59	$29.61	$33.57	$29.31	$27.15	$27.19	$25.18	$25.86	$23.95	$24.60	$22.78
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$100.01	$189.07	$179.41	$181.97	$182.82	$171.18	$171.97	$164.42	$165.18	$158.00	$158.71
Annual Maintenance Cost (2022$)	$0.48	$0.21	$0.22	$0.20	$0.17	$0.19	$0.16	$0.18	$0.15	$0.18	$0.14
Total Installed Cost (2022$/klm)	$20.51	$37.20	$41.14	$35.81	$33.13	$33.68	$31.17	$32.35	$29.93	$31.09	$28.76
Annual Maintenance Cost (2022$/klm)	$0.10	$0.04	$0.05	$0.04	$0.03	$0.04	$0.03	$0.04	$0.03	$0.03	$0.03

1. Data and assumptions taken from the 2018 SSL Forecast. The report states that efficacy improvements for T8 lamps are not expected in the future, and that the cost for all commercial fixtures is expected to decrease between 0.1%-0.6% per year. We use 0.5% per year here.
2. From 2020 to 2050, fixture (and fixture price) includes ballast.

Note: Assume no labor is associated with lamp replacement in the residential sector because residents likely replace lamps themselves.

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Performance and Cost Characteristics » Residential Linear Fluorescent Lamp T5

Final

DATA	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	27.0	27.5	28.0	27.5	26.0	27.5	26.0	27.5	26.0	27.5	26.0
Lamp Lumens	2,697	2,732	2,530	2,732	2,900	2,732	2,900	2,732	2,900	2,732	2,900
Lamp Efficacy (lm/W)[1]	100	99	90	99	112	99	112	99	112	99	112
System Wattage	51.5	61.7	62.9	61.7	58.4	61.7	58.4	61.7	58.4	61.7	58.4
System Lumens	4,747	5,464	5,060	5,464	5,800	5,464	5,800	5,464	5,800	5,464	5,800
System Efficacy (lm/W)	92	89	81	89	99	89	99	89	99	89	99
Ballast Efficiency (BLE)	92%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%
CRI	85	85	85	85	85	85	85	85	85	85	85
Correlated Color Temperature (CCT)	4,100	4,100	5,000	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	30	29	36	29	30	29	30	29	30	29	30
Annual Operating Hours (h/y)	949	949	949	949	949	949	949	949	949	949	949
Lamp Price (2022$)	$7.05	$9.54	$13.76	$9.45	$21.28	$9.08	$20.44	$8.63	$19.44	$8.21	$18.49
Ballast Price (2022$)[2]	$31.17	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$109.93	$170.87	$170.87	$170.87	$170.87	$164.15	$164.15	$156.13	$156.13	$148.50	$148.50
Lamp Cost (2022$/klm)	$2.61	$3.49	$5.44	$3.46	$7.34	$3.32	$7.05	$3.16	$6.70	$3.01	$6.38
System (l/b/f) Cost (2022$/klm)	$32.69	$34.77	$39.21	$34.73	$36.80	$33.37	$35.35	$31.73	$33.62	$30.18	$31.98
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$193.80	$228.57	$231.39	$222.77	$246.43	$215.31	$238.04	$206.40	$228.02	$197.92	$218.48
Annual Maintenance Cost (2022$)	$0.45	$0.62	$0.73	$0.62	$1.35	$0.59	$1.29	$0.57	$1.23	$0.54	$1.17
Total Installed Cost (2022$/klm)	$40.83	$41.83	$45.73	$40.77	$42.49	$39.41	$41.04	$37.77	$39.31	$36.22	$37.67
Annual Maintenance Cost (2022$/klm)	$0.09	$0.11	$0.14	$0.11	$0.23	$0.11	$0.22	$0.10	$0.21	$0.10	$0.20

1. Year-to-year price and performance assumptions for incumbent technologies 2030–2050: Efficacy +0.5%/yr, Life +0.5%/yr, Cost -0.5%/yr (SSL Forecast 2018). 2020 data back calculated using the 2022 data and these assumptions
2. From 2020 to 2050, fixture (and fixture price) includes ballast.

Note: Assume no labor is associated with lamp replacement in the residential sector because residents likely replace lamps themselves.

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Performance and Cost Characteristics » Residential Linear LED Replacement Lamp 2-Lamp System

Final

DATA	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	18.5	16.3	16.0	13.7	11.0	11.6	9.3	10.0	8.0	8.8	7.2
Lamp Lumens	2,013	2,130	1,800	1,920	1,800	1,920	1,800	1,920	1,800	1,920	1,800
Lamp Efficacy (lm/W)	111.0	130.7	112.5	140.1	163.6	166.2	194.1	192.2	224.4	218.0	250.0
System Wattage	36.9	32.6	32.0	27.4	22.0	23.1	18.6	20.0	16.0	17.6	14.4
System Lumens	3,583	4,004	3,384	3,686	3,456	3,686	3,456	3,686	3,456	3,686	3,456
System Efficacy (lm/W)	97.0	122.8	105.8	134.5	157.1	159.6	186.3	184.5	215.4	209.3	240.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	83	82	82	81	80	81	80	81	80	81	80
Correlated Color Temperature (CCT)	4,100	3,500	4,100	4,100	5,000	4,100	5,000	4,100	5,000	4,100	5,000
Average Lamp Life (thousand hours)	55	50	50	54	50	54	50	54	50	54	50
Annual Operating Hours (h/y)	730	730	730	730	730	730	730	730	730	730	730
Lamp Price (2022$)	$27.00	$12.89	$14.63	$11.11	$4.28	$9.97	$3.84	$9.87	$3.80	$9.77	$3.77
Ballast Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$13.41	$6.05	$8.13	$5.79	$2.38	$5.19	$2.13	$5.14	$2.11	$5.09	$2.09
System (l/b/f) Cost (2022$/klm)	N/A	$6.44	$8.65	$6.03	$2.48	$5.41	$2.22	$5.35	$2.20	$5.30	$2.18
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor System Installation (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$54.00	$25.78	$29.26	$22.22	$8.56	$19.95	$7.68	$19.74	$7.60	$19.55	$7.53
Annual Maintenance Cost (2022$)	$0.72	$0.38	$0.43	$0.30	$0.12	$0.27	$0.11	$0.27	$0.11	$0.26	$0.11
Total Installed Cost (2022$/klm)	$15.07	$6.44	$8.65	$6.03	$2.48	$5.41	$2.22	$5.35	$2.20	$5.30	$2.18
Annual Maintenance Cost (2022$/klm)	$0.20	$0.09	$0.13	$0.08	$0.04	$0.07	$0.03	$0.07	$0.03	$0.07	$0.03

1. N/A because a fixture and an LED replacement lamp would not be purchased separately for a new installation or retrofit when there are integrated LED luminaires that are more efficient and cost effective. These lamps are sold only as replacements to go into existing fixtures.

Note: Assume no labor is associated with lamp replacement in the residential sector because residents likely replace lamps themselves.

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Performance and Cost Characteristics » Residential Linear LED Luminaire

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DATA	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	50.0	43.1	49.0	44.0	35.0	35.6	28.3	29.9	23.8	25.8	20.5
System Lumens	4,615	4,945	5,024	5,302	4,800	5,302	4,800	5,302	4,800	5,302	4,800
System Efficacy (lm/W)	92.3	114.7	102.5	120.5	137.1	148.8	169.3	177.2	201.7	205.5	233.9
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	83	82	80	79	80	79	80	79	80	79	80
Correlated Color Temperature (CCT)	3,838	3,000	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	56	58	54	53	50	53	50	53	50	53	50
Annual Operating Hours (h/y)	584	584	584	584	584	584	584	584	584	584	584
Lamp or Luminaire Price (2022$)	$181.60	$158.60	$144.85	$152.54	$207.80	$121.11	$164.98	$105.34	$143.50	$90.11	$122.76
Ballast Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$78.70	$64.15	$57.66	$57.54	$86.58	$45.68	$68.74	$39.74	$59.79	$33.99	$51.15
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$401.81	$355.81	$322.70	$338.08	$448.60	$275.22	$362.97	$243.68	$320.01	$213.23	$278.52
Annual Maintenance Cost (2022$)	$2.30	$1.97	$1.92	$2.04	$2.81	$1.70	$2.31	$1.52	$2.06	$1.36	$1.82
Total Installed Cost (2022$/klm)	$87.07	$71.95	$64.23	$63.76	$93.46	$51.91	$75.62	$45.96	$66.67	$40.22	$58.03
Annual Maintenance Cost (2022$/klm)	$0.50	$0.40	$0.38	$0.39	$0.59	$0.32	$0.48	$0.29	$0.43	$0.26	$0.38

1. N/A because the lamp and fixture are both included in the luminaire.

Performance and Cost Characteristics » Residential Outdoor Lamps

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- The residential outdoor lamps characterized in this report include reflector and general service lamps used for security and/or porch lighting that can be switched on from inside the home (i.e. parking lot/garage and outdoor common area lighting at multifamily buildings are excluded) with lumen outputs of approximately 1,000 – 1,400 lumens. Multiple baseline lamps were analyzed according to estimates of installed base average lumens by lamp type, including:

Security (Reflector Lamps)	Porch (General Service Lamps)
Incandescent BR30	Incandescent A-Type
Halogen PAR38	Halogen A-Type
Halogen Infrared Reflector (HIR) PAR38	CFL Bare Spiral
CFL PAR38	LED A-Type Lamp
LED PAR38	

Performance:

- 65W BR30 is the only viable incandescent reflector lamp due to exemption from EISA 2007. The lumen output of this lamp type is well below other reflector lamp technologies characterized for residential outdoor spaces, thus its use is limited for this application. This product is, as of 2022, expected to be eliminated by DOE's 45 lm/W backstop requirement.
- A majority of residential lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2015 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Fixture prices and installation costs are not included for the residential sector. Labor costs are assumed to be negligible because homeowners likely replaces lamps themselves as they burn out. Therefore, total installed cost is the price of a lamp, and annual maintenance costs are the cost of replacing the lamps, which is a function of lamp life, lamp price, and the annual operating hours for residential reflector lamps.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Performance and Cost Characteristics » Residential Outdoor Lamps

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Legislation:

- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. **This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps.** These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

ENERGY STAR:

- For ENERGY STAR qualification, general service omnidirectional lamps must have a minimum lamp efficacy of 70 lm/W for products with CRI ≥ 90 and 80 lm/W for lamps with CRI < 90.
- For ENERGY STAR qualification, general service reflector lamps must have a minimum lamp efficacy of 61 lm/W for products with CRI ≥ 90 and 70 lm/W for lamps with CRI < 90.
- Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent Omnidirectional	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Incandescent Directional	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
CFL	+0.5%	0%	-0.5%	In addition to benefiting from higher efficiency reflector coatings, improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Security: Incandescent BR30)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	65.0	65.0	N/A	65.0	N/A	N/A	13.3	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	637	637	N/A	602	N/A	N/A	600	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	9.8	9.8	N/A	9.3	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	2.0	2.0	N/A	2.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	621	621	N/A	621	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$4.00	$4.00	N/A	$3.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$6.28	$6.28	N/A	$6.15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$4.00	$4.00	N/A	$3.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$1.24	$1.24	N/A	$1.15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$6.28	$6.28	N/A	$6.15	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.95	$1.95	N/A	$1.91	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. Incandescent BR30 lamps were previously exempted from DOE Incandescent Reflector Lamp standards and the EISA 2007 general service lamp definition until DOE's new final rule in 2022. The new definitions go into effect in 2023.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with incandescent technologies.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Security: Halogen PAR38)

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DATA	2015	2020	2022				2023[1]	2030[1]		2040[1]		2050[1]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	88.7	78.7	N/A	70.0	N/A	N/A	29.1	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,323	1,316	N/A	1,308	N/A	N/A	1,308	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	14.9	16.9	N/A	18.7	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,900	2,900	N/A	2,900	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	2.4	2.4	N/A	1.4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	876	876	N/A	876	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$6.24	$9.15	N/A	$10.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$4.71	$6.96	N/A	$7.89	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$6.24	$9.15	N/A	$10.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$2.28	$3.34	N/A	$6.62	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$4.71	$6.96	N/A	$7.89	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.72	$2.54	N/A	$5.06	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with halogen technologies.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Security: HIR PAR38)

Final

DATA	2015	2020	2022				2023[1]	2030[1]		2040[1]		2050[1]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	70.0	70.0	N/A	70.0	N/A	N/A	28.0	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,407	1,334	N/A	1,260	N/A	N/A	1,260	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	20.1	19.1	N/A	18.0	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,850	N/A	2,900	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	3.6	3.6	N/A	3.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	876	876	N/A	876	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$21.85	$27.31	N/A	$29.49	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$15.53	$20.48	N/A	$23.40	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$21.85	$27.31	N/A	$29.49	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$5.32	$6.64	N/A	$8.61	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$15.53	$20.48	N/A	$23.40	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$3.78	$4.98	N/A	$6.83	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with halogen technologies.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Security: CFL PAR38)

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DATA	2015[1]	2020[1]	2022[2]				2023[3]	2030[3]		2040[3]		2050[3]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	23.0	22.4	N/A	N/A	N/A	N/A	28.9	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,300	1,300	N/A	N/A	N/A	N/A	1,300	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	56.5	57.9	N/A	N/A	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	82	82	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	10.0	10.3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	913	913	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$8.52	$8.31	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$6.55	$6.39	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$8.52	$8.31	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$0.78	$0.74	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$6.55	$6.39	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$0.60	$0.57	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. 2015 and 2020 data calculated based on 2009 installed stock data and the following assumptions: Efficacy +0.5%/y, Cost -0.5%/y (NCI, 2019)
2. Virtually all manufacturers have discontinued manufacturing of CFL reflector lamps in favor of LEDs. Distributor offerings for CFL reflectors have been eliminated.
3. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. Although these standards can be met with CFL technology, manufacturers have discontinued manufacturing CFL reflector lamps in favor of LEDs.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Security: LED PAR38)

Final

DATA	2015	2020	2022				2023[1]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	19.2	15.5	17.0	16.4	17.0	22.0	29.9	14.0	14.6	12.3	12.7	10.9	11.3
Lamp Lumens	1,202	1,211	1,200	1,344	1,700	1,344	1,344	1,344	1,700	1,344	1,700	1,344	1,700
Lamp Efficacy (lm/W)	62.7	77.9	70.6	82.0	100.0	61.0	45.0	95.7	116.7	109.5	133.5	123.2	150.2
CRI	83	86	82	86	82	80	N/A	86	86	86	86	86	86
Correlated Color Temperature (CCT)	3,000	3,000	2,700	3,000	3,000	3,000	N/A	3,000	3,000	3,000	3,000	3,000	3,000
Average Lamp Life (thousand hours)	24	27	25	27	25	15	N/A	27	25	27	25	27	25
Annual Operating Hours (h/y)	730	730	730	730	730	N/A	N/A	730	730	730	730	730	730
Lamp Price (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Lamp Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Annual Maintenance Cost (2022$)	$1.07	$0.60	$0.69	$0.62	$0.46	N/A	N/A	$0.52	$0.38	$0.46	$0.34	$0.41	$0.31
Total Installed Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Annual Maintenance Cost (2022$/klm)	$0.89	$0.49	$0.58	$0.46	$0.27	N/A	N/A	$0.39	$0.23	$0.35	$0.20	$0.31	$0.18

1. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.
2. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)

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Performance and Cost Characteristics » Residential Outdoor Lamps (Porch: Incandescent A19)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	75.0	75.0	N/A	N/A	N/A	N/A	26.0	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,170	1,170	N/A	N/A	N/A	N/A	1,170	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	15.6	15.6	N/A	N/A	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	0.8	0.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	511	511	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$0.44	$0.44	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$0.38	$0.38	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Installation (hours)	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$0.44	$0.44	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$0.30	$0.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$0.38	$0.38	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$0.26	$0.26	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 (EISA 2007) prescribes standards for 75 watt incandescent lamps as of January 1, 2013. Despite the phase out of incandescent lamps, these products remain in the installed stock.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards cannot be met with incandescent technologies.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Porch: Halogen A19)

Final

DATA	2015[1]	2020[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	53.0	53.0	N/A	53.0	N/A	N/A	19.8	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1050	936	N/A	890	N/A	N/A	890	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	19.8	17.7	N/A	16.8	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,950	N/A	2,950	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	1.0	1.0	N/A	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	621	621	N/A	621	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$2.37	$3.58	N/A	$4.06	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$2.26	$3.82	N/A	$4.56	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$0.00	$0.00	N/A	$0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Installation (hours)	0	0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$2.37	$3.58	N/A	$4.06	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$1.47	$2.22	N/A	$2.52	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$2.26	$3.82	N/A	$4.56	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.40	$2.37	N/A	$2.83	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 prescribes standards for current 75 watt incandescent lamps as of January 1, 2013. Starting in 2013, 75 watt incandescent lamps were replaced by halogen lamps.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards cannot be met with existing halogen lamp technologies.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Porch: CFL Bare Spiral)

Final

DATA	2015	2020[1]	2022				2023[3]	2030[4]		2040[4]		2050[4]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	18.6	14.6	20.0	18.8	18.0	13.8	26.0	13.9	12.8	13.2	12.2	12.5	11.6
Lamp Lumens	1,216	900	1,100	1,171	1,250	800	1,171	900	925	900	925	900	925
Lamp Efficacy (lm/W)	65.4	61.8	55.0	62.4	69.4	80.0	45.0	65.0	72.3	68.3	76.0	71.8	79.9
CRI	82	82	85	83	82	80	N/A	83	82	83	82	83	82
Correlated Color Temperature (CCT)	2,700	2,700	5,000	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	10.0	10.0	12.0	10.4	10.0	10.0	N/A	10.4	10.0	10.4	10.0	10.4	10.0
Annual Operating Hours (h/y)	767	767	767	767	767	N/A	N/A	767	767	767	767	767	767
Lamp Price (2022$)	$3.82	$5.33	$9.00	$5.28	$5.91	N/A	N/A	$5.07	$5.67	$4.82	$5.40	$4.59	$5.13
Lamp Cost (2022$/klm)	$3.14	$5.92	$8.18	$4.51	$4.72	N/A	N/A	$5.63	$6.13	$5.36	$5.83	$5.10	$5.55
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0	0	0	0	0	N/A	N/A	0	0	0	0	0	0
Total Installed Cost (2022$)	$3.82	$5.33	$9.00	$5.28	$5.91	N/A	N/A	$5.07	$5.67	$4.82	$5.40	$4.59	$5.13
Annual Maintenance Cost (2022$)	$0.29	$0.41	$0.58	$0.39	$0.45	N/A	N/A	$0.37	$0.44	$0.36	$0.41	$0.34	$0.39
Total Installed Cost (2022$/klm)	$3.14	$5.92	$8.18	$4.51	$4.72	N/A	N/A	$5.63	$6.13	$5.36	$5.83	$5.10	$5.55
Annual Maintenance Cost (2022$/klm)	$0.24	$0.45	$0.52	$0.33	$0.36	N/A	N/A	$0.42	$0.47	$0.40	$0.45	$0.38	$0.43

1. 2020 data back calculated based on 2022 data and the following assumptions: Efficacy +0.5%/y, Cost -0.5%/y (NCI, 2019)
2. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
3. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. CFL products exceed the new minimum efficacy standards.
4. The market for 75W equivalent bare spiral CFLs is very limited because almost all product lines are discontinued. This trend is expected to continue until no products are offered at this level by 2030.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Porch: LED A-Type)

Final

DATA	2015	2020	2022				2023[1]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	12.9	11.8	13.5	11.9	11.0	13.6	24.4	9.9	9.1	7.7	7.1	6.7	6.2
Lamp Lumens	1,073	1,102	1,100	1,089	1,100	1,089	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Lamp Efficacy (lm/W)	83.1	93.5	81.5	92.2	100.0	80	45.0	111.5	120.9	142.0	154.0	164.6	178.6
CRI	81	85	80	86	80	80	N/A	86	80	86	80	86	80
Correlated Color Temperature (CCT)	2,700	2,700	3,000	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	25	21	25	18	25	15	N/A	18	25	18	25	18	25
Annual Operating Hours (h/y)	657	657	657	657	657	N/A	N/A	657	657	657	657	657	657
Lamp Price (2022$)	$18.13	$8.48	$4.39	$3.92	$5.29	N/A	N/A	$3.23	$4.36	$2.84	$3.84	$2.46	$3.31
Lamp Cost (2022$/klm)	$16.90	$7.70	$3.99	$3.60	$4.81	N/A	N/A	$7.02	$7.02	$3.57	$3.57	$2.38	$2.38
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$18.13	$8.48	$4.39	$3.92	$5.29	N/A	N/A	$3.23	$4.36	$2.84	$3.84	$2.46	$3.31
Annual Maintenance Cost (2022$)	$0.49	$0.27	$0.12	$0.14	$0.14	N/A	N/A	$0.12	$0.11	$0.10	$0.10	$0.09	$0.09
Total Installed Cost (2022$/klm)	$16.90	$7.70	$3.99	$3.60	$4.81	N/A	N/A	$2.94	$3.97	$2.59	$3.49	$2.23	$3.01
Annual Maintenance Cost (2022$/klm)	$0.45	$0.24	$0.10	$0.13	$0.13	N/A	N/A	$0.11	$0.10	$0.09	$0.09	$0.08	$0.08

1. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.
2. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)

Commercial Lighting

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Performance and Cost Characteristics » Commercial General Service Lamps in Recessed Can Fixtures

Final

This section characterizes commercial omnidirectional incandescent, halogen, CFL, and LED screw-based general service lamps emitting approximately 1,600 lumens (equivalent to a 100W incandescent lamp) used in recessed can fixtures. A recessed can is a directional fixture set into the ceiling, in which all of the light is directed downwards from the opening. Therefore, an omnidirectional lamp is not well suited for use in such fixtures because light that emits upwards and out of the sides must be reflected downwards and out of the fixture and some light is absorbed in the process. A fixture efficiency of 61% is used to characterize these lumen losses for all omnidirectional lamps. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- A majority of general service lamps have a nominal CCT rating of 2,700 K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps which are sold only as a replacement for use in an existing fixture. There are integrated LED luminaires that are more efficient and cost effective for new installations or fixture retrofits. Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore typical lamp prices in 2015 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial general service lamps (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for high intensity discharge (HID) lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- The Energy Independence and Security Act of 2007 (EISA 2007) established standards for 100W lamps effective in 2012. These standards cannot be achieved by incandescent bulbs, but they can be met by halogen, CFL, and LED technologies from 2012 to 2023.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps. These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

ENERGY STAR:

- For ENERGY STAR qualification, general service omnidirectional lamps must have a minimum lamp efficacy of 70 lm/W for products with CRI ≥ 90 and 80 lm/W for lamps with CRI < 90. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

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Performance and Cost Characteristics » Commercial General Service Lamps in Recessed Can Fixtures

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022
CFL	+0.5%	0%	-0.5%	Improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Commercial General Service 100W Incandescent Lamp in Recessed Can Fixture

Final

DATA	2012[1]	2018[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	100.0	100.0	N/A	N/A	N/A	N/A	36.0	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,620	1,620	N/A	N/A	N/A	N/A	1,620	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	16.2	16.2	N/A	N/A	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	100.0	100.0	N/A	N/A	N/A	N/A	36.0	N/A	N/A	N/A	N/A	N/A	N/A
System Lumens[3]	988	988	N/A	N/A	N/A	N/A	988	N/A	N/A	N/A	N/A	N/A	N/A
System Efficacy (lm/W)	9.9	9.9	N/A	N/A	N/A	N/A	27.5	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,700	2,700	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	0.8	0.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	4,015	4,015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$0.67	$0.67	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$23.72	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$0.41	$0.41	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$24.68	$24.68	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor System Installation (hours)	1.0	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.05	0.05	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$101.61	$101.61	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$24.25	$24.25	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$102.83	$102.83	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$24.54	$24.54	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 (EISA 2007) prescribes standards for 100 watt incandescent lamps as of January 1, 2012. Despite the phase out of incandescent lamps, these products remain in the installed stock.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. These standards cannot be met with incandescent technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. Note: the 45 lm/W backstop applies to the lamp, not the calculated fixture efficacy.
3. Based on a fixture efficiency of 61% for an omnidirectional lamp installed in a recessed can fixture.

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Performance and Cost Characteristics » Commercial General Service Halogen Lamp (100W Incandescent Equivalent) in Recessed Can Fixture

Final

DATA	2012[1]	2018[1]	2022[2]				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	72.0	72.0	N/A	72.0	N/A	N/A	33.1	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,490	1,490	N/A	1,490	N/A	N/A	1,490	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	20.7	20.7	N/A	20.7	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	72.0	72.0	N/A	72.0	N/A	N/A	33.1	N/A	N/A	N/A	N/A	N/A	N/A
System Lumens[3]	909	909	N/A	909	N/A	N/A	909	N/A	N/A	N/A	N/A	N/A	N/A
System Efficacy (lm/W)	12.6	12.6	N/A	12.6	N/A	N/A	27.5	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	3,000	N/A	3,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	1.0	1.0	N/A	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	4,015	4,015	N/A	4,015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$2.33	$5.16	N/A	$4.02	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$26.38	N/A	$22.07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$1.57	$3.46	N/A	$2.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$28.67	$34.71	N/A	$28.71	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	N/A	$66.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor System Installation (hours)	1.0	1.0	N/A	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.05	0.05	N/A	0.05	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$103.28	$108.77	N/A	$92.09	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$24.87	$36.23	N/A	$29.39	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$113.63	$119.67	N/A	$101.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$27.36	$39.86	N/A	$32.34	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. The Energy Independence and Security Act of 2007 (EISA 2007) prescribes standards for 100 watt incandescent lamps as of January 1, 2012. Starting in 2012, 100 watt incandescent lamps were replaced by halogen lamps.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. These standards cannot be met with existing commercialized halogen lamp technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. Note: the 45 lm/W backstop applies to the lamp, not the calculated fixture efficacy.
3. Based on a fixture efficiency of 61% for an omnidirectional lamp installed in a recessed can fixture.

Additional note: No products are currently marketed specifically as 100W equivalent HIR general service lamps and no available data from manufacturers. It is assumed this market is the same as 100W equivalent halogen lamps.

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Performance and Cost Characteristics » Commercial General Service 100W Equivalent CFL Bare Spiral in Recessed Can Fixture

Final

DATA	2012	2018	2022				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	24.7	24.6	25.0	24.6	26.0	26.0	37.6	23.6	25.0	22.5	23.8	21.4	22.6
Lamp Lumens	1,680	1,680	1,600	1,694	1,835	1,600	1,694	1,694	1,835	1,694	1,835	1,694	1,835
Lamp Efficacy (lm/W)	68.1	68.2	64.0	68.9	70.6	80.0	45.0	71.7	73.4	75.3	77.2	79.2	81.2
System Wattage	24.7	24.6	25.0	24.6	26.0	26.0	37.6	23.6	25.0	22.5	23.8	21.4	22.6
System Lumens[3]	1,025	1,025	976	1,033	1,119	976	1,033	1,033	1,119	1,033	1,119	1,033	1,119
System Efficacy (lm/W)	41.6	41.6	39.0	42.0	43.1	37.5	27.5	43.7	44.8	46.0	47.1	48.3	49.5
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	82	82	82	82	82	82	N/A	82	82	82	82	82	82
Correlated Color Temperature (CCT)	3,000	3,000	2,700	3,000	5,000	3,000	N/A	3,000	3,000	3,000	3,000	3,000	3,000
Average Lamp Life (thousand hours)	10.0	10.0	10.0	10.0	10.0	10.0	N/A	10.0	10.0	10.0	10.0	10.0	10.0
Annual Operating Hours (h/y)	4,745	4,745	4,745	4,745	4,745	N/A	N/A	4,745	4,745	4,745	4,745	4,745	4,745
Lamp Price (2022$) [4]	$3.08	$6.40	$9.90	$8.62	$9.35	N/A	N/A	$8.28	$8.98	$7.87	$8.54	$7.49	$8.13
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$) [4]	$23.72	$26.38	$22.07	$22.07	$22.07	N/A	N/A	$21.20	$21.20	$20.17	$20.17	$19.18	$19.18
Disposal Cost (2022$)	$0.50	$0.50	$0.50	$0.50	$0.50	N/A	N/A	$0.50	$0.50	$0.50	$0.50	$0.50	$0.50
Lamp Cost (2022$/klm)	$1.84	$3.81	$6.19	$5.09	$5.10	N/A	N/A	$4.89	$4.90	$4.65	$4.66	$4.42	$4.43
System (l/b/f) Cost (2022$/klm)	$26.15	$31.98	$32.76	$29.70	$28.07	N/A	N/A	$28.53	$26.97	$27.13	$25.65	$25.81	$24.39
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	N/A	N/A	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.0	1.0	1.0	1.0	1.0	N/A	N/A	1.0	1.0	1.0	1.0	1.0	1.0
Labor Lamp Change (hours)	0.05	0.05	0.05	0.05	0.05	N/A	N/A	0.05	0.05	0.05	0.05	0.05	0.05
Total Installed Cost (2022$)	$104.03	$110.01	$97.97	$96.69	$97.42	N/A	N/A	$95.48	$96.18	$94.04	$94.71	$92.67	$93.31
Annual Maintenance Cost (2022$)	$3.53	$5.11	$6.50	$5.89	$6.24	N/A	N/A	$5.73	$6.07	$5.54	$5.86	$5.36	$5.66
Total Installed Cost (2022$/klm)	$101.48	$107.32	$100.38	$93.57	$87.03	N/A	N/A	$92.40	$85.93	$91.00	$84.61	$89.68	$83.36
Annual Maintenance Cost (2022$/klm)	$3.45	$4.98	$6.66	$5.70	$5.57	N/A	N/A	$5.55	$5.42	$5.36	$5.23	$5.18	$5.06

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. These standards can be met with existing CFL products. Note: the 45 lm/W backstop applies to the lamp, not the calculated fixture efficacy.
3. Based on a fixture efficiency of 61% for an omnidirectional lamp installed in a recessed can fixture.
4. Year-to-year price and performance assumptions 2022 – 2050: Efficacy +0.5%, Equipment Cost -0.5%

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Performance and Cost Characteristics » Commercial General Service 100W Equivalent LED Replacement Lamp in Recessed Can Fixture

Final

DATA	2012	2018	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	26.7	14.5	16.0	14.8	13.0	20.0	34.8	12.2	10.8	9.6	8.4	8.3	7.3
Lamp Lumens	1,600	1,528	1,600	1,567	1,600	1,600	1,567	1,567	1,600	1,567	1,600	1,567	1,600
Lamp Efficacy (lm/W)	60.0	105.1	100.0	106.0	123.1	80.0	45.0	128.2	148.8	163.3	189.5	189.3	219.8
System Wattage	26.7	14.5	16.0	14.8	13.0	20.0	34.8	12.2	10.8	9.6	8.4	8.3	7.3
System Lumens[3]	976	932	976	956	976	976	956	956	976	956	976	956	976
System Efficacy (lm/W)	36.6	64.1	61.0	64.7	75.1	48.8	27.5	78.2	90.8	99.6	115.6	115.5	134.1
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	80	80	90	84.8	84	80	N/A	84.8	84.8	84.8	84.8	84.8	84.8
Correlated Color Temperature (CCT)	3,000	3,000	2,700	2,700	5,000	N/A	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	22.0	17.9	25.0	16.9	25.0	15.0	N/A	16.9	25.0	16.9	25.0	16.9	25.0
Annual Operating Hours (h/y)	4,928	4,928	4,928	4,928	4,928	N/A	N/A	4,928	4,928	4,928	4,928	4,928	4,928
Lamp Price (2022$)	$47.45	$11.28	$5.62	$7.04	$3.39	N/A	N/A	$5.81	$2.80	$5.11	$2.46	$4.41	$2.12
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$26.38	$22.07	$22.07	$22.07	N/A	N/A	$21.20	$21.20	$20.17	$20.17	$19.18	$19.18
Lamp Cost (2022$/klm)	$25.00	$7.38	$3.51	$4.49	$2.12	N/A	N/A	$3.71	$1.75	$3.26	$1.54	$2.82	$1.33
System (l/b/f) Cost (2022$/klm)	$72.92	$40.40	$28.37	$30.46	$26.09	N/A	N/A	$28.26	$24.59	$26.45	$23.18	$24.68	$21.83
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	N/A	N/A	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.0	1.0	1.0	1.0	1.0	N/A	N/A	1.0	1.0	1.0	1.0	1.0	1.0
Labor Lamp Change (hours)	0.05	0.05	0.05	0.05	0.05	N/A	N/A	0.05	0.05	0.05	0.05	0.05	0.05
Total Installed Cost (2022$)	$148.39	$114.88	$93.69	$95.11	$91.46	N/A	N/A	$93.01	$90.00	$91.27	$88.63	$89.59	$87.30
Annual Maintenance Cost (2022$)	$11.49	$4.16	$1.76	$3.02	$1.32	N/A	N/A	$2.66	$1.20	$2.45	$1.14	$2.25	$1.07
Total Installed Cost (2022$/klm)	$152.04	$123.25	$95.99	$99.52	$93.71	N/A	N/A	$97.32	$92.21	$95.51	$90.81	$93.75	$89.45
Annual Maintenance Cost (2022$/klm)	$11.77	$4.46	$1.80	$3.16	$1.35	N/A	N/A	$2.78	$1.23	$2.57	$1.16	$2.35	$1.10

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards. Note: the 45 lm/W backstop applies to the lamp, not the calculated fixture efficacy.
3. Based on a fixture efficiency of 61% for an omnidirectional lamp installed in a recessed can fixture.

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Performance and Cost Characteristics » Commercial Reflector Lamps in Recessed Can Fixtures

Final

This section characterizes commercial halogen, halogen infrared reflector (HIR), and LED screw-based reflector lamps emitting approximately 1400 lumens used in recessed can fixtures.

- HIR lamps contain a tungsten halogen capsule with a film coating on the inside of the capsule. The coating reflects infrared radiation back into the lamp filament, which forces the filament to burn at a higher temperature. This design increases the efficacy of the lamp, without reducing operating life.
- A recessed can is a directional fixture set into the ceiling, in which all of the light is directed downwards from the opening. Therefore, a reflector lamp, which employs reflective coating to direct light out in only one direction, is well suited for use in such fixtures. However, some light is not able to escape the fixture, and a fixture efficiency of 93% is used to characterize these minimal lumen losses. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- A majority of reflector lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps which are sold only as a replacement for use in an existing fixture. Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial reflector lamps (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- EPAct92 established minimum performance standards for some reflector lamps and provided exemptions for certain specialty applications (e.g., ER/BR, vibration service, more than 5% neodymium oxide, impact resistant, infrared heat, colored). EPAct92 effectively phased-out R-shaped tungsten filament incandescent reflector lamps at certain wattages and bulb diameters, replacing them with more efficient and cost effective tungsten-halogen parabolic aluminized reflector (PAR) lamps. EISA2007 took away certain exemptions from EPACT 1992, requiring certain previously exempted lamps to meet EPAct92 minimum performance standards by January 1, 2008. In 2015, DOE issued a final rule that determined that amending the standards for incandescent reflector lamps could not be economically justified.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. **This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps.** These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

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Performance and Cost Characteristics » Commercial Reflector Lamps in Recessed Can Fixtures

Final

ENERGY STAR:

- For ENERGY STAR qualification, general service reflector lamps must have a minimum lamp efficacy of 61 lm/W for products with CRI ≥ 90 and 70 lm/W for lamps with CRI < 90. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022
CFL	+0.5%	0%	-0.5%	In addition to higher efficiency reflector coatings, improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Commercial Halogen Reflector Lamp (PAR38) in Recessed Can Fixture

Final

DATA	2012	2018	2022				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	90.0	87.3	N/A	70.0	N/A	N/A	29.1	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,323	1,323	N/A	1,308	N/A	N/A	1,308	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	14.7	15.1	N/A	18.7	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	90.0	87.3	N/A	70.0	N/A	N/A	29.1	N/A	N/A	N/A	N/A	N/A	N/A
System Lumens[1]	1,230	1,230	N/A	1,217	N/A	N/A	1,217	N/A	N/A	N/A	N/A	N/A	N/A
System Efficacy (lm/W)	13.7	14.1	N/A	17.4	N/A	N/A	41.9	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,850	N/A	2,850	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	2.4	2.4	N/A	1.4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	4,052	4,052	N/A	4,052	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$4.49	$7.99	N/A	$10.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$26.38	N/A	$22.07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$3.39	$6.04	N/A	$7.89	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$22.93	$27.93	N/A	$26.62	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	N/A	$66.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor System Installation (hours)	1.0	1.0	N/A	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.05	0.05	N/A	0.05	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$105.43	$111.59	N/A	$98.39	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$14.09	$20.00	N/A	$40.40	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$85.69	$90.70	N/A	$80.86	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$11.46	$16.26	N/A	$33.20	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. Based on a fixture efficiency of 93% for an directional reflector lamp installed in a recessed can fixture.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with existing commercialized halogen lamp technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

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Performance and Cost Characteristics » Commercial Halogen Infrared Reflector Lamp (PAR38) in Recessed Can Fixture

Final

DATA	2012	2018	2022				2023[2]	2030[2]		2040[2]		2050[2]	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	70.0	70.0	N/A	70.0	N/A	N/A	28.0	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	1,407	1,407	N/A	1,260	N/A	N/A	1,260	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	20.1	20.1	N/A	18.0	N/A	N/A	45.0	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	70.0	70.0	N/A	70.0	N/A	N/A	28.0	N/A	N/A	N/A	N/A	N/A	N/A
System Lumens[1]	1,309	1,309	N/A	1,172	N/A	N/A	1,172	N/A	N/A	N/A	N/A	N/A	N/A
System Efficacy (lm/W)	18.7	18.7	N/A	16.7	N/A	N/A	41.9	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	100	100	N/A	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Correlated Color Temperature (CCT)	2,850	2,850	N/A	2,850	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Lamp Life (thousand hours)	3.6	3.6	N/A	3.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Operating Hours (h/y)	4,052	4,052	N/A	4,052	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Price (2022$)	$18.58	$25.12	N/A	$29.49	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$26.38	N/A	$22.07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$13.20	$17.86	N/A	$23.40	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$32.33	$39.36	N/A	$44.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	N/A	$66.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor System Installation (hours)	1.0	1.0	N/A	1.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.05	0.05	N/A	0.05	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$119.52	$128.73	N/A	$117.56	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$25.25	$32.62	N/A	$44.28	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$91.34	$98.38	N/A	$100.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$19.30	$24.93	N/A	$37.79	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1. Based on a fixture efficiency of 93% for an directional reflector lamp installed in a recessed can fixture.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. These standards cannot be met with existing commercialized halogen lamp technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

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Performance and Cost Characteristics » Commercial LED Reflector Lighting (PAR38)

Final

DATA	2012	2018	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[3]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	17.2	16.6	17.0	16.4	17.0	22.0	29.9	14.0	14.6	12.3	12.7	10.9	11.3
Lamp Lumens	1,045	1,210	1,200	1,344	1,700	1,344	1,344	1,344	1,700	1,344	1,700	1,344	1,700
Lamp Efficacy (lm/W)	60.9	73.0	70.6	82.0	100.0	61.0	45.0	95.7	116.7	109.5	133.5	123.2	150.2
System Wattage	17.2	16.6	17.0	16.4	17.0	22.0	29.9	14.0	14.6	12.3	12.7	10.9	11.3
System Lumens[1]	972	1,125	1,116	1,250	1,581	1,250	1,250	1,250	1,581	1,250	1,581	1,250	1,581
System Efficacy (lm/W)	56.6	67.9	65.6	76.1	93.0	56.7	41.9	89.0	108.6	101.9	124.2	114.6	139.7
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	83	83	82	86	82	80	N/A	86	82	86	82	86	82
Correlated Color Temperature (CCT)	3,000	3,000	2,700	3,000	3,000	3,000	N/A	3,000	3,000	3,000	3,000	3,000	3,000
Average Lamp Life (thousand hours)	22	15	25	28	25	25	N/A	28	25	28	25	28	25
Annual Operating Hours (h/y)	4,928	4,928	4,928	4,928	4,928	N/A	N/A	4,928	4,928	4,928	4,928	4,928	4,928
Lamp Price (2022$)	$61.98	$28.10	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$26.38	$22.07	$22.07	$22.07	N/A	N/A	$21.20	$21.20	$20.17	$20.17	$19.18	$19.18
Lamp Cost (2022$/klm)	$59.31	$23.23	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
System (l/b/f) Cost (2022$/klm)	$88.18	$48.42	$41.02	$36.13	$23.88	N/A	N/A	$32.48	$21.75	$30.02	$20.22	$27.64	$18.74
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	N/A	N/A	$91.40	$91.40	$91.40	$91.40	$91.40	$91.40
Labor System Installation (hours)	1.0	1.0	1.0	1.0	1.0	N/A	N/A	1.0	1.0	1.0	1.0	1.0	1.0
Labor Lamp Change (hours)	0.05	0.05	0.05	0.05	0.05	N/A	N/A	0.05	0.05	0.05	0.05	0.05	0.05
Total Installed Cost (2022$)	$162.93	$131.71	$111.78	$111.16	$103.76	N/A	N/A	$132.00	$125.78	$128.92	$123.36	$125.95	$121.02
Annual Maintenance Cost (2022$)	$14.75	$10.50	$5.32	$4.64	$3.74	N/A	N/A	$4.22	$3.50	$3.86	$3.23	$3.51	$2.96
Total Installed Cost (2022$/klm)	$167.64	$117.04	$100.16	$88.92	$65.63	N/A	N/A	$105.59	$79.56	$103.13	$78.02	$100.75	$76.55
Annual Maintenance Cost (2022$/klm)	$15.17	$9.33	$4.77	$3.72	$2.37	N/A	N/A	$3.37	$2.21	$3.09	$2.04	$2.81	$1.87

1. Based on a fixture efficiency of 93% for an omnidirectional lamp installed in a recessed can fixture.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. All LED lighting products exceed the new minimum efficacy standards.
3. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)

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Performance and Cost Characteristics » Commercial 4-foot Linear 2-Lamp Lighting Systems

Final

This section characterizes commercial linear fixtures that house two 4ft long linear lamps and their integrated luminaire equivalents. The technologies available for this system are linear fluorescent and LED.

- Linear fluorescent options are T5, T8, and T12 lamps. T5 lamps are approximately 40% narrower than T8 lamps and almost 60% narrower than T12 lamps. This narrowness allows T5 lamps to be coated with higher quality, more efficient phosphor blends than larger diameter lamps, resulting in a more efficacious lamp. The compact size of T5 lamps also permits greater flexibility in lighting design and construction.
- LED options for linear fixtures include replacement lamps that can fit directly into an existing fixture and fully integrated luminaires that can be used to replace existing fixtures. LED replacement lamps are also known as TLEDs. Type A TLEDs can be installed with existing ballasts and Type B and C TLEDs require the ballast to be disconnected. Replacement lamps are only sold to go into existing fixtures. If a new fixture is to be installed, a fully integrated LED luminaire is a more cost effective and efficient option. Because LED luminaires are fully integrated, they do not have lamp or fixture efficiency losses associated with ballasts and fixture optics. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- Linear lamps often have a nominal CCT rating of 3,500K, but products with CCTs of 3,000K, 4,000K, and 4,100K (neutral white) are also common. 5,000K (daylight) lamps are available as well. When replacing a light bulb, it is important to choose a product with a similar CCT value to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but for CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- The total installed cost is the price of 2 lamps, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps, which are sold only as a replacement for use in an existing fixture. There are integrated LED luminaires that are more efficient and cost effective for new installations or fixture retrofits. Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore typical lamp prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours of 4055 hours/year for commercial 4ft linear systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- Beginning July 14, 2012 (or July 14, 2014, for T8 700-series phosphor lamps), DOE fluorescent lamp standards required a minimum efficacy of 89 lm/W. Although the amended performance-based standards do not explicitly prohibit T12 lamps, no T12 lamps met the standard at the time of its announcement. Since then, however, T12 lamps meeting the standard have entered the market.
- California's Title 24 mandates the use of electronic ballasts with high efficacy luminaires (including fluorescent) of 13 W or higher (CEC, 2005).

ENERGY STAR:

- ENERGY STAR does not cover commercial linear luminaires (ENERGY STAR, 2020).

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Performance and Cost Characteristics » Commercial 4-foot Linear 2-Lamp Lighting Systems

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
T8 F32 Commodity	0%	0%	-0.5%	Limited because the technology is mature.
T8 F32 High Efficiency/High Output	0%	0%	-0.5%	Limited because the technology is mature.
T5 F28	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Commercial 4-ft T8 F32 Commodity in 2-Lamp System

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average[1]	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
Lamp Lumens	2,725	2,855	2,450	2,855	3,100	2,855	3,100	2,855	3,100	2,855	3,100
Lamp Efficacy (lm/W)	85.2	89.0	76.6	89.2	96.9	89.2	96.9	89.2	96.9	89.2	96.9
System Wattage	61.8	62.5	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1
System Lumens	4,796	5,082	4,361	5,082	5,518	5,082	5,518	5,082	5,518	5,082	5,518
System Efficacy (lm/W)	77.7	81.4	69.1	80.6	87.5	80.6	87.5	80.6	87.5	80.6	87.5
Ballast Efficiency (BLE)	91%	91%	90%	90%	90%	90%	90%	90%	90%	90%	90%
CRI	83	87	90	87	85	87	85	87	85	87	85
Correlated Color Temperature (CCT)	4,100	4,100	5,000	4,100	3,500	4,100	3,500	4,100	3,500	4,100	3,500
Average Lamp Life (thousand hours)	24	31	23	31	40	31	40	31	40	31	40
Annual Operating Hours (h/y)	4,055	2,920	2,920	2,920	2,920	2,920	2,920	2,920	2,920	2,920	2,920
Lamp Price (2022$)	$7.81	$5.02	$3.36	$4.08	$4.32	$3.92	$4.15	$3.73	$3.95	$3.55	$3.75
Ballast Price (2022$)[2]	$19.56	$19.40	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$29.67	$77.61	$75.53	$75.53	$75.53	$72.56	$72.56	$69.01	$69.01	$65.64	$65.64
Disposal Costs (2022$)	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Lamp Cost (2022$/klm)	$2.86	$1.76	$1.37	$1.43	$1.39	$1.37	$1.34	$1.31	$1.27	$1.24	$1.21
System (l/b/f) Cost (2022$/klm)	$13.52	$21.07	$33.57	$29.31	$27.15	$15.91	$14.65	$15.05	$13.94	$14.31	$13.26
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$103.45	$145.67	$179.41	$181.97	$182.82	$113.86	$113.86	$109.47	$109.91	$105.73	$106.15
Annual Maintenance Cost (2022$)	$7.89	$3.88	$4.24	$3.28	$2.58	$3.25	$2.55	$3.21	$2.52	$3.18	$2.49
Total Installed Cost (2022$/klm)	$21.57	$28.66	$41.14	$35.81	$33.13	$22.41	$20.63	$21.54	$19.92	$20.81	$19.24
Annual Maintenance Cost (2022$/klm)	$1.65	$0.76	$0.97	$0.65	$0.47	$0.64	$0.46	$0.63	$0.46	$0.63	$0.45

1. Data and assumptions taken from the 2018 SSL Forecast. The report states that efficacy improvements for T8 lamps are not expected in the future and that cost for all commercial fixtures is expected to decrease between 0.1%-0.6% per year. We use 0.5% per year here.
2. From 2020 to 2050, fixture (and fixture price) includes ballast.

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Performance and Cost Characteristics » Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average[2]	Typical	Typical	Typical	Typical
Lamp Wattage	28.0	28.0	28.0	28.0	28.0	28.0
Lamp Lumens	2,560	2,682	2,682	2,682	2,682	2,682
Lamp Efficacy (lm/W)	91	96	96	96	96	96
System Wattage	55.4	55.4	55.4	55.4	55.4	55.4
System Lumens	4,557	4,774	4,774	4,774	4,774	4,774
System Efficacy (lm/W)	82	86	86	86	86	86
Ballast Efficiency (BLE)	90%	90%	90%	90%	90%	90%
CRI	85	84	84	84	84	84
Correlated Color Temperature (CCT)	4,100	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	24	48	48	48	48	48
Annual Operating Hours (h/y)	4,055	2,920	2,920	2,920	2,920	2,920
Lamp Price (2022$)	$11.17	$5.40	$5.29	$5.08	$4.84	$4.60
Ballast Price (2022$)[3]	$19.56	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$35.20	$77.05	$75.53	$72.56	$69.01	$65.64
Disposal Costs (2022$)	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Lamp Cost (2022$/klm)	$4.36	$2.01	$1.97	$1.90	$1.80	$1.71
System (l/b/f) Cost (2022$/klm)	$30.12	$32.75	$32.11	$30.85	$29.34	$27.90
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$104.54	$121.06	$113.82	$110.64	$106.85	$103.24
Annual Maintenance Cost (2022$)	$9.03	$2.54	$2.26	$2.23	$2.20	$2.17
Total Installed Cost (2022$/klm)	$22.94	$25.36	$23.84	$23.18	$22.38	$21.63
Annual Maintenance Cost (2022$/klm)	$1.98	$0.53	$0.47	$0.47	$0.46	$0.46

1. Only a typical dataset because provided as these lamps all have similar efficacies.
2. Data and assumptions taken from the 2018 SSL Forecast. The report states that efficacy improvements for T8 lamps are not expected in the future and that cost for all commercial fixtures is expected to decrease between 0.1%-0.6% per year. We use 0.5% per year here.
3. From 2018 to 2050, fixture (and fixture price) includes ballast.

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Performance and Cost Characteristics » Commercial 4-ft T5 F28 in 2-Lamp System

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	28.0	27.7	28.0	27.5	26.0	27.5	26.0	27.5	26.0	27.5	26.0
Lamp Lumens	2,697	2,732	2,530	2,732	2,900	2,732	2,900	2,732	2,900	2,732	2,900
Lamp Efficacy (lm/W)	96.3	98.5	90.4	99.3	111.5	99.3	111.5	99.3	111.5	99.3	111.5
System Wattage	62.9	62.3	62.9	61.7	58.4	61.7	58.4	61.7	58.4	61.7	58.4
System Lumens	5,394	5,464	5,060	5,464	5,800	5,464	5,800	5,464	5,800	5,464	5,800
System Efficacy (lm/W)	85.8	87.8	80.5	88.5	99.4	88.5	99.4	88.5	99.4	88.5	99.4
Ballast Efficiency (BLE)	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%
CRI	85	85	85	85	85	85	85	85	85	85	85
Correlated Color Temperature (CCT)	4,100	3,500	5,000	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	30	29	36	29	30	29	30	29	30	29	30
Annual Operating Hours (h/y)	4,055	3,176	3,176	3,176	3,176	3,176	3,176	3,176	3,176	3,176	3,176
Lamp Price (2022$)[1]	$6.54	$6.96	$13.76	$9.45	$21.28	$9.08	$20.44	$8.63	$19.44	$8.21	$18.49
Ballast Price (2022$)[2]	$31.94	$22.83	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$111.59	$83.32	$170.87	$170.87	$170.87	$164.15	$164.15	$156.13	$156.13	$148.50	$148.50
Disposal Costs (2022$)	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Lamp Cost (2022$/klm)	$2.42	$2.55	$5.44	$3.46	$7.34	$3.32	$7.05	$3.16	$6.70	$3.01	$6.38
System (l/b/f) Cost (2022$/klm)	$29.03	$21.97	$39.21	$34.73	$36.80	$37.53	$35.35	$31.73	$33.62	$30.18	$31.98
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$195.22	$158.68	$231.39	$222.77	$246.43	$238.04	$238.04	$206.40	$228.02	$197.92	$218.48
Annual Maintenance Cost (2022$)	$5.97	$4.93	$4.78	$4.99	$7.33	$4.91	$7.15	$4.81	$6.94	$4.72	$6.74
Total Installed Cost (2022$/klm)	$36.19	$29.04	$45.73	$40.77	$42.49	$43.57	$41.04	$37.77	$39.31	$36.22	$37.67
Annual Maintenance Cost (2022$/klm)	$1.11	$0.90	$0.94	$0.91	$1.26	$0.90	$1.23	$0.88	$1.20	$0.86	$1.16

1. Year-to-year price and performance assumptions for incumbent technologies 2030–2050: Efficacy +0%/y, Life +0%/y, Cost -0.5%/y (SSL Forecast 2018).
2. From 2020 to 2050, fixture (and fixture price) includes ballast.

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Performance and Cost Characteristics » Commercial 4-ft Linear LED Replacement Lamp in 2-Lamp System

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	20.8	17.0	16.0	13.7	11.0	11.6	9.3	10.0	8.0	8.8	7.2
Lamp Lumens	2,091	2,003	1,800	1,920	1,800	1,920	1,800	1,920	1,800	1,920	1,800
Lamp Efficacy (lm/W)	100.5	117.8	112.5	140.1	163.6	166.2	194.1	192.2	224.4	218.0	250.0
System Wattage	41.6	34.0	32.0	27.4	22.0	23.1	18.6	20.0	16.0	17.6	14.4
System Lumens	3,555	3,565	3,456	3,686	3,456	3,686	3,456	3,686	3,456	3,686	3,456
System Efficacy (lm/W)	85.4	104.9	108.0	134.5	157.1	159.6	186.3	184.5	215.4	209.3	240.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	86	81	82	81	80	81	80	81	80	81	80
Correlated Color Temperature (CCT)	4,100	4,020	4,100	4,100	5,000	4,100	5,000	4,100	5,000	4,100	5,000
Average Lamp Life (thousand hours)	50	54	50	54	50	54	50	54	50	54	50
Annual Operating Hours (h/y)	4,055	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541
Lamp Price (2022$)	$278.36	$35.06	$14.63	$11.11	$4.28	$9.88	$3.81	$9.66	$3.72	$9.44	$3.64
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$133.10	$17.50	$8.13	$5.79	$2.38	$5.15	$2.11	$5.03	$2.07	$4.92	$2.02
System (l/b/f) Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$587.35	$70.12	$29.26	$22.22	$8.56	$19.76	$7.61	$19.31	$7.44	$18.89	$7.28
Annual Maintenance Cost (2022$)	$47.64	$6.61	$3.93	$3.17	$2.46	$3.01	$2.39	$2.98	$2.38	$2.95	$2.37
Total Installed Cost (2022$/klm)	$165.20	$19.67	$8.47	$6.03	$2.48	$5.36	$2.20	$5.24	$2.15	$5.12	$2.11
Annual Maintenance Cost (2022$/klm)	$13.40	$1.85	$1.14	$0.86	$0.71	$0.82	$0.69	$0.81	$0.69	$0.80	$0.69

1. N/A because a fixture and an LED replacement lamp would not be purchased separately for a new installation or retrofit when there are integrated LED luminaires that are more efficient and cost effective. These lamps are sold only as replacements to go into existing fixtures.

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Performance and Cost Characteristics » Commercial 4-ft Linear LED Luminaire to Replace 2-Lamp Systems

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	51.5	50.0	49.0	44.0	35.0	35.6	28.3	29.9	23.8	25.8	20.5
System Lumens	4,818	4,673	5,024	5,302	4,800	5,302	4,800	5,302	4,800	5,302	4,800
System Efficacy (lm/W)	93.6	93.5	102.5	120.5	137.1	148.8	169.3	177.2	201.7	205.5	233.9
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	84	79	80	79	80	79	80	79	80	79	80
Correlated Color Temperature (CCT)	3,500	3,650	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Average Lifetime (thousand hours)	67	53	54	53	50	53	50	53	50	53	50
Annual Operating Hours (h/y)	4,055	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431
Lamp or Luminaire Price (2022$)	$723.96	$188.00	$144.85	$152.54	$207.80	$127.58	$173.80	$118.37	$161.25	$109.57	$149.27
Ballast Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$150.25	$40.23	$57.66	$57.54	$86.58	$24.06	$36.21	$22.33	$33.59	$20.67	$31.10
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$762.57	$226.61	$322.70	$338.08	$448.60	$160.58	$206.80	$151.37	$194.25	$142.57	$182.27
Annual Maintenance Cost (2022$)	$46.16	$14.67	$11.30	$12.01	$16.52	$10.40	$14.19	$9.80	$13.33	$9.23	$12.51
Total Installed Cost (2022$/klm)	$158.27	$48.49	$64.23	$63.76	$93.46	$30.29	$43.08	$28.55	$40.47	$26.89	$37.97
Annual Maintenance Cost (2022$/klm)	$9.58	$3.14	$2.25	$2.27	$3.44	$1.96	$2.96	$1.85	$2.78	$1.74	$2.61

1. N/A because the lamp and fixture are both included in the luminaire.

U21806-MNSC-CE-0771-Att 4

Performance and Cost Characteristics » Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System with Occupancy Sensor

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average[2]	Typical	Typical	Typical	Typical
Lamp Wattage	28.0	28.0	28.0	28.0	28.0	28.0
Lamp Lumens	2,560	2,682	2,682	2,682	2,682	2,682
Lamp Efficacy (lm/W)	91	96	96	96	96	96
System Wattage	50.3	55.4	55.4	55.4	55.4	55.4
System Lumens	4,506	4,774	4,774	4,774	4,774	4,774
System Efficacy (lm/W)	90	86	86	86	86	86
Ballast Efficiency (BLE)	90%	90%	90%	90%	90%	90%
CRI	85	84	84	84	84	84
Correlated Color Temperature (CCT)	4,100	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	24	48	48	48	48	48
Annual Operating Hours (h/y)[3]	4,055	2,920	1,869	1,869	1,869	1,869
Lamp Price (2022$)	$11.17	$5.40	$5.29	$5.08	$4.84	$4.60
Ballast Price (2022$)	$19.56	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$35.20	$77.05	$75.53	$72.56	$69.01	$65.64
Occupancy Sensor Price (2022$)	N/A	N/A	$161.34	$161.34	$161.34	$161.34
Disposal Costs (2022$)	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Lamp Cost (2022$/klm)	$4.36	$2.01	$1.97	$1.90	$1.80	$1.71
System (l/b/f) Cost (2022$/klm)	$30.12	$32.75	$92.26	$91.00	$89.49	$88.06
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$104.54	$121.06	$275.16	$271.98	$268.19	$264.58
Annual Maintenance Cost (2022$)	$9.03	$2.54	$1.44	$1.43	$1.41	$1.39
Total Installed Cost (2022$/klm)	$23.20	$25.36	$57.64	$56.97	$56.18	$55.42
Annual Maintenance Cost (2022$/klm)	$2.00	$0.53	$0.30	$0.30	$0.30	$0.29

1. Only a typical dataset is provided because these lamps all have similar efficacies.
2. Data and assumptions taken from the 2018 SSL Forecast. The report states that efficacy improvements for T8 lamps are not expected in the future and that cost for all commercial fixtures is expected to decrease between 0.1%-0.6% per year. We use 0.5% per year here.
3. Assumes occupancy sensor reduces hours of use by 36% (NCI, 2019)

U21806-MNSC-CE-0771-Att 4

Performance and Cost Characteristics » Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System with Specular Reflector

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average[2]	Typical	Typical	Typical	Typical
Lamp Wattage	28.0	28.0	28.0	28.0	28.0	28.0
Lamp Lumens	2,560	2,682	2,682	2,682	2,682	2,682
Lamp Efficacy (lm/W)	91.4	95.8	95.8	95.8	95.8	95.8
System Wattage	55.4	55.4	55.4	55.4	55.4	55.4
System Lumens[3]	4,506	4,774	5,347	5,347	5,347	5,347
System Efficacy (lm/W)	81	86	97	97	97	97
Ballast Efficiency (BLE)	90%	90%	90%	90%	90%	90%
CRI	85	84	84	84	84	84
Correlated Color Temperature (CCT)	4,100	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	24	48	48	48	48	48
Annual Operating Hours (h/y)	2,920	4,055	4,055	4,055	4,055	4,055
Lamp Price (2022$)	$11.17	$5.40	$5.29	$5.08	$4.84	$4.60
Ballast Price (2022$)	$19.56	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$35.20	$77.05	$75.53	$72.56	$69.01	$65.64
Reflector Price (2022$)	N/A	N/A	$44.53	$44.53	$44.53	$44.53
Disposal Costs (2022$)	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Lamp Cost (2022$/klm)	$4.36	$2.01	$1.97	$1.90	$1.80	$1.71
System (l/b/f) Cost (2022$/klm)	$30.12	$32.75	$48.71	$47.45	$45.94	$44.51
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$104.54	$121.06	$158.35	$155.17	$151.38	$147.77
Annual Maintenance Cost (2022$)	$6.50	$3.53	$3.13	$3.10	$3.06	$3.02
Total Installed Cost (2022$/klm)	$23.20	$25.36	$29.62	$29.02	$28.31	$27.64
Annual Maintenance Cost (2022$/klm)	$1.44	$0.74	$0.59	$0.58	$0.57	$0.56

1. Only a typical dataset is provided because these lamps all have similar efficacies.
2. Data and assumptions taken from the 2018 SSL Forecast. The report states that efficacy improvements for T8 lamps are not expected in the future and that cost for all commercial fixtures is expected to decrease between 0.1%-0.6% per year. We use 0.5% per year here.
3. Specular reflector is expected to add 12% luminaire efficiency (LRC, 1992).

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Performance and Cost Characteristics » Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System with Occupancy Sensor and Specular Reflector

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average[2]	Typical	Typical	Typical	Typical
Lamp Wattage	28.0	28.0	28.0	28.0	28.0	28.0
Lamp Lumens	2,560	2,682	2,682	2,682	2,682	2,682
Lamp Efficacy (lm/W)	91.4	95.8	95.8	95.8	95.8	95.8
System Wattage	50.3	55.4	55.4	55.4	55.4	55.4
System Lumens[3]	4,506	4,774	5,347	5,347	5,347	5,347
System Efficacy (lm/W)	89.6	86.2	96.6	96.6	96.6	96.6
Ballast Efficiency (BLE)	90%	90%	90%	90%	90%	90%
CRI	85	84	84	84	84	84
Correlated Color Temperature (CCT)	4,100	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	24	48	48	48	48	48
Annual Operating Hours (h/y)[3]	4,055	2,920	1,869	1,869	1,869	1,869
Lamp Price (2022$)	$11.17	$5.40	$5.29	$5.08	$4.84	$4.60
Ballast Price (2022$)	$19.56	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$35.20	$77.05	$75.53	$72.56	$69.01	$65.64
Reflector Price (2022$)	N/A	N/A	$44.53	$44.53	$44.53	$44.53
Occupancy Sensor Price (2022$)	N/A	N/A	$161.34	$161.34	$161.34	$161.34
Disposal Costs (2022$)	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Lamp Cost (2022$/klm)	$4.36	$2.01	$1.97	$1.90	$1.80	$1.71
System (l/b/f) Cost (2022$/klm)	$30.12	$32.75	$108.87	$107.61	$106.10	$104.66
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$104.54	$121.06	$319.69	$316.51	$312.72	$309.11
Annual Maintenance Cost (2022$)	$9.03	$2.54	$1.44	$1.43	$1.41	$1.39
Total Installed Cost (2022$/klm)	$23.20	$25.36	$59.79	$59.20	$58.49	$57.81
Annual Maintenance Cost (2022$/klm)	$2.00	$0.53	$0.27	$0.27	$0.26	$0.26

1. Only a typical dataset is provided because these lamps all have similar efficacies.
2. Data and assumptions taken from the 2018 SSL Forecast. The report states that efficacy improvements for T8 lamps are not expected in the future and that cost for all commercial fixtures is expected to decrease between 0.1%-0.6% per year. We use 0.5% per year here.
3. Assumes occupancy sensor reduces hours of use by 36% (NCI, 2019). Specular reflector is expected to add 12% luminaire efficiency (LRC, 1992).

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Performance and Cost Characteristics » Commercial 8-foot Linear 2-Lamp Lighting Systems

Final

This section characterizes commercial linear fixtures that house two 8ft long linear lamps and their integrated luminaire equivalents. The technologies available for this system are linear fluorescent and LED.

- Linear fluorescent options are T5, T8, and T12 lamps. T5 lamps are approximately 40% narrower than T8 lamps and almost 60% narrower than T12 lamps. This narrowness allows T5 lamps to be coated with higher quality, more efficient phosphor blends than larger diameter lamps, resulting in a more efficacious lamp. The compact size of T5 lamps also permits greater flexibility in lighting design and construction.
- LED options for linear fixtures include replacement lamps that can fit directly into an existing fixture and fully integrated luminaires that can be used to replace existing fixtures. LED replacement lamps are also known as TLEDs. Type A TLEDs can be installed with existing ballasts and Type B and C TLEDs require the ballast to be disconnected. Replacement lamps are only sold to go into existing fixtures. If a new fixture is to be installed, a fully integrated LED luminaire is a more cost effective and efficient option. Because LED luminaires are fully integrated, they do not have lamp or fixture efficiency losses associated with ballasts and fixture optics. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- Linear lamps often have a nominal CCT rating of 3,500K, but products with CCTs of 3,000K, 4,000K, and 4,100K (neutral white) are also common. 5,000K (daylight) lamps are available as well. When replacing a light bulb, it is important to choose a product with a similar CCT value to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but for CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- The total installed cost is the price of 2 lamps, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps which are sold only as a replacement for use in an existing fixture. There are integrated LED luminaires that are more efficient and cost effective for new installations or fixture retrofits. Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore typical lamp prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours of 4147 hours/year for commercial 8ft linear systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- Beginning July 14, 2012 (or July 14, 2014, for T8 700-series phosphor lamps), DOE fluorescent lamp standards required a minimum efficacy of 89 lm/W. Although the amended performance-based standards do not explicitly prohibit T12 lamps, no T12 lamps met the standard at the time of its announcement. Since then, however, T12 lamps meeting the standard have entered the market.
- California's Title 24 mandates the use of electronic ballasts with high efficacy luminaires (including fluorescent) of 13 W or higher (CEC, 2005).

ENERGY STAR:

- ENERGY STAR does not cover commercial linear luminaires (ENERGY STAR, 2020).

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Performance and Cost Characteristics » Commercial 8-foot Linear 2-Lamp Lighting Systems

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume the manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050:

Technology	Efficacy	Lifetime	Price	Potential for Improvements
T8 F59 Typical Efficiency	0%	0%	-0.5%	Limited because the technology is mature.
T8 F59 High Efficiency	0%	0%	-0.5%	Limited because the technology is mature.
T8 F96 High Output	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Commercial 8-ft T8 F59 Typical Efficiency in a 2-Lamp System

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0	59.0
Lamp Lumens	5,430	5,788	5,900	5,905	5,950	5,905	5,950	5,905	5,950	5,905	5,950
Lamp Efficacy (lm/W)	92.0	98.1	100.0	100.1	100.8	100.1	100.8	100.1	100.8	100.1	100.8
System Wattage	106.8	111.6	112.9	112.9	112.9	112.9	112.9	112.9	112.9	112.9	112.9
System Lumens	9,448	10,071	10,384	10,393	10,472	10,393	10,472	10,393	10,472	10,393	10,472
System Efficacy (lm/W)	88.5	90.3	92.0	92.1	92.8	92.1	92.8	92.1	92.8	92.1	92.8
Ballast Efficiency (BLE)	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
CRI	82	84	85	84	85	84	85	84	85	84	85
Correlated Color Temperature (CCT)	4,100	4,100	3,500	4,100	3,500	4,100	3,500	4,100	3,500	4,100	3,500
Average Lamp Life (thousand hours)	24	21	24	21	24	21	24	21	24	21	24
Annual Operating Hours (h/y)	4,147	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066
Lamp Price (2022$)	$14.70	$21.80	$23.58	$21.37	$22.84	$20.53	$21.94	$19.53	$20.87	$18.57	$19.85
Ballast Price (2022$)	$23.26	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	$27.20	$117.38	$115.06	$115.06	$115.06	$110.54	$110.54	$105.13	$105.13	$99.99	$99.99
Disposal Costs (2022$)	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96
Lamp Cost (2022$/klm)	$2.28	$3.77	$4.00	$3.62	$3.84	$3.48	$3.69	$3.31	$3.51	$3.15	$3.34
System (l/b/f) Cost (2022$/klm)	$12.40	$15.99	$15.62	$15.18	$15.35	$14.59	$14.75	$13.87	$14.03	$13.20	$13.34
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.0	1.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Labor Lamp Change (hours)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Installed Cost (2022$)	$114.60	$238.20	$247.36	$242.94	$245.88	$236.74	$239.56	$229.33	$232.01	$222.28	$224.83
Annual Maintenance Cost (2022$)	$8.98	$9.66	$8.51	$9.08	$8.32	$8.83	$8.09	$8.54	$7.82	$8.26	$7.55
Total Installed Cost (2022$/klm)	$12.13	$23.65	$23.82	$23.38	$23.48	$22.78	$22.88	$22.07	$22.16	$21.39	$21.47
Annual Maintenance Cost (2022$/klm)	$0.95	$0.96	$0.82	$0.87	$0.79	$0.85	$0.77	$0.82	$0.75	$0.79	$0.72

1. From 2018 to 2050, fixture (and fixture price) includes ballast.

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Performance and Cost Characteristics » Commercial 8-ft T8 F96 High-Output in a 2-Lamp System

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0
Lamp Lumens	7600	8134	7710	8134	8200	8134	8200	8134	8200	8134	8200
Lamp Efficacy (lm/W)	88.4	94.6	89.7	94.6	95.3	94.6	95.3	94.6	95.3	94.6	95.3
System Wattage	148.4	183.6	183.6	183.6	183.6	183.6	183.6	183.6	183.6	183.6	183.6
System Lumens	12,026	15,455	14,649	15,455	15,580	15,455	15,580	15,455	15,580	15,455	15,580
System Efficacy (lm/W)	81.0	84.2	79.8	84.2	84.9	84.2	84.9	84.2	84.9	84.2	84.9
Ballast Efficiency (BLE)	92%	89%	89%	89%	89%	89%	89%	89%	89%	89%	89%
CRI	78	85	85	85	85	85	85	85	85	85	85
Correlated Color Temperature (CCT)	4,100	4,100	3,500	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100
Average Lamp Life (thousand hours)	18	22	18	22	30	22	30	22	30	22	30
Annual Operating Hours (h/y)	4,147	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066
Lamp Price (2022$)	$20.22	$30.62	$16.51	$30.02	$73.42	$28.84	$70.53	$27.43	$67.09	$26.09	$63.81
Ballast Price (2022$)	$18.55	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	$27.20	$117.38	$115.06	$115.06	$115.06	$110.54	$110.54	$105.13	$105.13	$99.99	$99.99
Disposal Costs (2022$)	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96	$0.96
Lamp Cost (2022$/klm)	$2.24	$3.77	$2.14	$3.69	$8.95	$3.55	$8.60	$3.37	$8.18	$3.21	$7.78
System (l/b/f) Cost (2022$/klm)	$21.99	$11.56	$10.11	$11.33	$16.81	$10.88	$16.15	$10.35	$15.36	$9.85	$14.61
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.0	1.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Labor Lamp Change (hours)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Installed Cost (2022$)	$143.19	$255.85	$233.22	$260.24	$347.04	$253.36	$336.75	$245.13	$324.44	$237.31	$312.74
Annual Maintenance Cost (2022$)	$13.48	$11.68	$8.94	$11.08	$16.99	$10.75	$16.40	$10.35	$15.70	$9.98	$15.03
Total Installed Cost (2022$/klm)	$17.89	$16.55	$15.92	$16.84	$22.27	$16.39	$21.61	$15.86	$20.82	$15.36	$20.07
Annual Maintenance Cost (2022$/klm)	$1.12	$0.76	$0.61	$0.72	$1.09	$0.70	$1.05	$0.67	$1.01	$0.65	$0.96

1. From 2018 to 2050, fixture (and fixture price) includes ballast.

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Performance and Cost Characteristics » Commercial 8-ft Linear LED Replacement Lamp for a 2 Lamp System

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	35.7	34.0	39.0	40.0	32.9	33.7	28.4	29.2	25.1	25.7
Lamp Lumens	N/A	3,975	4,200	4,960	5,500	4,960	5,500	4,960	5,500	4,960	5,500
Lamp Efficacy (lm/W)	N/A	111.2	123.5	127.2	137.5	150.8	163.1	174.4	188.6	197.9	213.9
System Wattage	N/A	71.5	68.0	78.0	80.0	65.8	67.5	56.9	58.3	50.1	51.4
System Lumens	N/A	7,473	8,064	9,523	10,560	9,523	10,560	9,523	10,560	9,523	10,560
System Efficacy (lm/W)	N/A	104.5	118.6	122.1	132.0	144.8	156.5	167.4	181.0	189.9	205.4
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	N/A	80	82	81	82	81	82	81	82	81	82
Correlated Color Temperature (CCT)	N/A	5,000	4,000	4,000	5,000	4,000	5,000	4,000	5,000	4,000	5,000
Average Lamp Life (thousand hours)	N/A	50	50	50	50	50	50	50	50	50	50
Annual Operating Hours (h/y)	N/A	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541
Lamp Price (2022$)	N/A	$89.59	$33.11	$37.22	$41.44	$32.35	$36.02	$31.71	$35.30	$31.11	$34.64
Ballast Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	N/A	$19.00	$7.88	$7.50	$7.53	$6.52	$6.55	$6.39	$6.42	$6.27	$6.30
System (l/b/f) Cost (2022$/klm)	N/A	$23.98	$8.21	$7.82	$7.85	$6.79	$6.82	$6.66	$6.69	$6.53	$6.56
Labor Cost (2022$/h)	N/A	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	N/A	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Installed Cost (2022$)	N/A	$179.18	$66.22	$74.44	$82.88	$64.70	$72.04	$63.42	$70.61	$62.22	$69.28
Annual Maintenance Cost (2022$)	N/A	$14.22	$6.00	$6.58	$7.18	$5.89	$6.41	$5.80	$6.31	$5.71	$6.21
Total Installed Cost (2022$/klm)	N/A	$45.08	$8.21	$7.82	$7.85	$6.79	$6.82	$6.66	$6.69	$6.53	$6.56
Annual Maintenance Cost (2022$/klm)	N/A	$3.58	$0.74	$0.69	$0.68	$0.62	$0.61	$0.61	$0.60	$0.60	$0.59

1. N/A because a fixture and an LED replacement lamp would not be purchased separately for a new installation or retrofit when there are integrated LED luminaires that are more efficient and cost effective. These lamps are sold only as replacements to go into existing fixtures.

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Performance and Cost Characteristics » Commercial 8-ft Linear LED Luminaire Replacement for a 2-Lamp System

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	N/A	73.0	90.0	78.0	72.0	64.6	59.6	55.2	50.9	48.1	44.4
System Lumens	N/A	8,000	8,200	9,465	10,400	9,465	10,400	9,465	10,400	9,465	10,400
System Efficacy (lm/W)	N/A	109.6	91.1	121.3	144.4	146.5	174.4	171.6	204.3	196.6	234.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	N/A	90	80	81	80	81	80	81	80	81	80
Correlated Color Temperature (CCT)	N/A	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Average Lifetime (thousand hours)	N/A	75	50	73	100	73	100	73	100	73	100
Annual Operating Hours (h/y)	N/A	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431
Lamp or Luminaire Price (2022$)	N/A	$759.16	$119.99	$142.48	$153.91	$109.90	$118.71	$96.00	$103.70	$82.68	$89.31
Ballast Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	N/A	$80.00	$14.63	$15.05	$14.80	$11.61	$11.41	$10.14	$9.97	$8.73	$8.59
Labor Cost (2022$/h)	N/A	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	N/A	1.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Labor Lamp Change (hours)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	N/A	$708.20	$206.52	$229.01	$240.44	$196.42	$205.24	$182.53	$190.23	$169.20	$175.83
Annual Maintenance Cost (2022$)	N/A	$39.16	$22.40	$17.46	$13.53	$14.40	$11.11	$13.09	$10.08	$11.84	$9.10
Total Installed Cost (2022$/klm)	N/A	$88.53	$25.18	$24.20	$23.12	$20.75	$19.73	$19.28	$18.29	$17.88	$16.91
Annual Maintenance Cost (2022$/klm)	N/A	$4.89	$2.73	$1.84	$1.30	$1.52	$1.07	$1.38	$0.97	$1.25	$0.87

1. N/A because the lamp and fixture are both included in the luminaire.

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Performance and Cost Characteristics » Commercial Low-Bay Lighting Systems

Final

The commercial low bay lighting characterized in this report is a one-lamp and one-ballast system in a low/high bay fixture that emits between 6,000 and 10,000 system lumens. Low bay lighting is defined as "interior lighting where the roof trusses or ceiling height is less than 25ft. above the floor"(IESNA, 2000). For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- Low bay conventional lighting technologies, such as metal halide and sodium vapor lamps, provide higher efficacy ranging from 80 lm/W to 100 lm/W. Older, mercury vapor lamps have much lower efficacy at approximately 40 lm/W.
- CCT and CRI values range broadly based on technology type for low bay products.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED luminaires, which are sold as one integrated system. Many factors influence the price of LED luminaires, including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical luminaire prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial low-bay systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

ENERGY STAR:

- ENERGY STAR does not cover low/high bay luminaires (ENERGY STAR, 2012).

Performance and Cost Characteristics » Commercial Low-Bay Lighting Systems

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- (Navigant, 2019). Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

	Efficacy	Lifetime	Price	Potential for Improvements
Mercury Vapor	0%	0%	-0.5%	Limited because the technology is mature.
Metal Halide	0%	0%	-0.5%	Limited because the technology is mature.
Sodium Vapor	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Commercial Mercury Vapor Low-Bay

Final

DATA[1]	2012	2018	2022	2030[2]	2040[2]	2050[2]
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	175.0	175.0	175.0	N/A	N/A	N/A
Lamp Lumens	7,400	7,400	7,400	N/A	N/A	N/A
Lamp Efficacy (lm/W)	42.3	42.3	44.0	N/A	N/A	N/A
System Wattage	205.9	205.9	205.9	N/A	N/A	N/A
System Lumens	7,400	7,400	7,400	N/A	N/A	N/A
System Efficacy (lm/W)	35.9	35.9	35.9	N/A	N/A	N/A
Ballast Efficiency	85%	85%	85%	N/A	N/A	N/A
CRI	33	33	33	N/A	N/A	N/A
Correlated Color Temperature (CCT)	3,700	3,700	3,700	N/A	N/A	N/A
Average Lamp Life (thousand hours)	24	24	24	N/A	N/A	N/A
Annual Operating Hours (h/y)	3,687	3,687	3,687	N/A	N/A	N/A
Lamp Price (2022$)	$13.96	$13.55	$13.80	N/A	N/A	N/A
Ballast Price (2022$)	$51.91	$50.37	$49.48	N/A	N/A	N/A
Fixture Price (2022$)	$38.73	$37.58	$36.83	N/A	N/A	N/A
Disposal Cost (2022$)	$1.50	$1.50	$1.50	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$1.89	$1.83	$1.86	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$14.13	$13.72	$13.53	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	N/A	N/A	N/A
Labor System Installation (hours)	1.5	1.5	1.5	N/A	N/A	N/A
Labor Lamp Change (hours)	0.5	0.5	0.5	N/A	N/A	N/A
Total Installed Cost (2022$)	$220.43	$217.33	$199.11	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$8.31	$8.24	$7.42	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$29.79	$29.37	$26.91	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$1.12	$1.11	$1.00	N/A	N/A	N/A

1. Only a typical dataset is provided because these lamps all have similar efficacies.
2. EPAct 2005 limited the sale and production of mercury vapor ballasts since 2008, and by 2030 there is no expected market for these products.

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Performance and Cost Characteristics » Commercial Metal Halide Low-Bay

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	100.0	100.0	100.0	100.0	100.0	100.0
Lamp Lumens	8,084	8,331	8,500	8,500	8,500	8,500
Lamp Efficacy (lm/W)	80.8	83.3	85.0	85.0	85.0	85.0
System Wattage	113.6	113.6	113.6	113.6	113.6	113.6
System Lumens	7,400	7,400	7,400	7,400	7,400	7,400
System Efficacy (lm/W)	65.1	65.1	65.1	65.1	65.1	65.1
Ballast Efficiency	88%	88%	88%	88%	88%	88%
CRI	80	80	80	80	80	80
Correlated Color Temperature (CCT)	4,000	4,000	4,000	4,000	4,000	4,000
Average Lamp Life (thousand hours)	15	15	15	15	15	15
Annual Operating Hours (h/y)	3,760	3,760	3,760	3,760	3,760	3,760
Lamp Price (2022$)	$17.97	$17.44	$17.10	$16.43	$15.62	$14.86
Ballast Price (2022$)	$57.97	$56.26	$49.48	$47.54	$45.21	$43.00
Fixture Price (2022$)	$38.73	$37.58	$36.83	$35.39	$33.66	$32.01
Disposal Cost (2022$)	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
Lamp Cost (2022$/klm)	$2.22	$2.09	$2.01	$1.93	$1.84	$1.75
System (l/b/f) Cost (2022$/klm)	$15.50	$15.04	$13.97	$13.43	$12.77	$12.14
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.5	1.5	1.5	1.5	1.5	1.5
Labor Lamp Change (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Total Installed Cost (2022$)	$230.51	$227.11	$202.41	$198.35	$193.49	$188.87
Annual Maintenance Cost (2022$)	$14.56	$14.43	$12.93	$12.76	$12.56	$12.37
Total Installed Cost (2022$/klm)	$31.15	$30.69	$27.35	$26.80	$26.15	$25.52
Annual Maintenance Cost (2022$/klm)	$1.97	$1.95	$1.75	$1.72	$1.70	$1.67

1. Only a typical dataset is provided because these lamps all have similar efficacies.

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Performance and Cost Characteristics » Commercial Sodium Vapor Low-Bay

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	100.0	100.0	100.0	100.0	100.0	100.0
Lamp Lumens	8,550	8,550	9,300	9,300	9,300	9,300
Lamp Efficacy (lm/W)	85.5	85.5	93.0	93.0	93.0	93.0
System Wattage	128.0	128.0	128.0	128.0	128.0	128.0
System Lumens	8,550	8,550	9,300	9,300	9,300	9,300
System Efficacy (lm/W)	66.8	66.8	72.6	72.6	72.6	72.6
Ballast Efficiency	78%	78%	78%	78%	78%	78%
CRI	22	22	22	22	22	22
Correlated Color Temperature (CCT)	2,100	2,100	2,100	2,100	2,100	2,100
Average Lamp Life (thousand hours)	24	24	24	24	24	24
Annual Operating Hours (h/y)	3,614	3,614	3,614	3,614	3,614	3,614
Lamp Price (2022$)	$54.04	$52.44	$13.14	$12.62	$12.01	$11.42
Ballast Price (2022$)	$56.14	$54.48	$43.26	$41.56	$39.53	$37.60
Fixture Price (2022$)	$128.14	$124.35	$121.88	$117.09	$111.36	$105.92
Disposal Cost (2022$)	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
Lamp Cost (2022$/klm)	$6.32	$6.13	$1.41	$1.36	$1.29	$1.23
System (l/b/f) Cost (2022$/klm)	$27.87	$27.05	$19.17	$18.42	$17.52	$16.66
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.5	1.5	1.5	1.5	1.5	1.5
Labor Lamp Change (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Total Installed Cost (2022$)	$354.16	$347.10	$277.28	$270.27	$261.90	$253.93
Annual Maintenance Cost (2022$)	$14.18	$13.93	$7.17	$7.10	$7.00	$6.91
Total Installed Cost (2022$/klm)	$41.42	$40.60	$29.81	$29.06	$28.16	$27.30
Annual Maintenance Cost (2022$/klm)	$1.66	$1.63	$0.77	$0.76	$0.75	$0.74

1. Only a typical dataset is provided because these lamps all have similar efficacies.

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Performance and Cost Characteristics » Commercial LED Low-Bay Luminaire

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	68.1	84.0	40.0	73.0	76.0	61.2	63.7	52.7	54.9	46.3	48.2
System Lumens	4,877	10,000	5,000	10,000	12,000	10,000	12,000	10,000	12,000	10,000	12,000
System Efficacy (lm/W)	71.6	119.0	125.0	137.0	157.9	163.4	188.4	189.7	218.7	216.0	248.9
Ballast Efficiency	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	85	78	84	81	80	81	84	81	84	81	81
Correlated Color Temperature (CCT)	4,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Average Lifetime (thousand hours)	50	74	75	65	60	65	60	65	60	65	60
Annual Operating Hours (h/y)	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042
Lamp or Luminaire Price (2022$)	$903.82	$281.00	$63.99	$145.46	$285.89	$123.82	$243.37	$111.24	$218.63	$99.09	$194.75
Ballast Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$185.31	$28.10	$12.80	$14.55	$23.82	$12.38	$20.28	$11.12	$18.22	$9.91	$16.23
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$865.44	$396.83	$162.99	$244.46	$384.89	$222.82	$342.37	$210.24	$317.63	$198.09	$293.75
Annual Maintenance Cost (2022$)	$69.95	$37.02	$12.23	$24.24	$45.18	$21.55	$39.45	$19.99	$36.12	$18.48	$32.90
Total Installed Cost (2022$/klm)	$177.44	$39.68	$32.60	$24.45	$32.07	$22.28	$28.53	$21.02	$26.47	$19.81	$24.48
Annual Maintenance Cost (2022$/klm)	$14.34	$3.70	$2.45	$2.42	$3.77	$2.16	$3.29	$2.00	$3.01	$1.85	$2.74

1. N/A because the lamp and fixture are both included in the luminaire.

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Performance and Cost Characteristics » Commercial High-Bay Lighting Systems

Final

The commercial high-bay lighting characterized in this report is a one-lamp and one-ballast system in a low/high bay fixture that emits greater than 10,000 system lumens. High-bay lighting is defined as "interior lighting where the roof trusses or ceiling height is greater than 25ft. above the floor" (IESNA, 2000). For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- High bay conventional lighting technologies, such as metal halide and sodium vapor lamps, provide higher efficacy ranging from 80 lm/W to 100 lm/W. Older, mercury vapor lamps have much lower efficacy at approximately 40 lm/W.
- CCT and CRI values range broadly based on technology type for high bay products.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED luminaires, which are sold as one integrated system. Many factors influence the price of LED luminaires including, CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical luminaire prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial high bay systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

ENERGY STAR:

- ENERGY STAR does not cover low/high bay luminaires (ENERGY STAR, 2012).

U21806-MNSC-CE-0771-Att 4

Performance and Cost Characteristics » Commercial High-Bay Lighting Systems

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

	Efficacy	Lifetime	Price	Potential for Improvements
Mercury Vapor	0%	0%	-0.5%	Limited because the technology is mature.
Metal Halide	0%	0%	-0.5%	Limited because the technology is mature.
Sodium Vapor	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Commercial Mercury Vapor High-Bay

Final

DATA[1]	2012	2018	2022	2030[2]	2040[2]	2050[2]
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	400.0	400.0	400.0	N/A	N/A	N/A
Lamp Lumens	15,800	15,800	21,000	N/A	N/A	N/A
Lamp Efficacy (lm/W)	39.5	39.5	52.5	N/A	N/A	N/A
System Wattage	449.4	449.4	449.4	N/A	N/A	N/A
System Lumens	15,800	15,800	21,000	N/A	N/A	N/A
System Efficacy (lm/W)	35.2	35.2	46.7	N/A	N/A	N/A
Ballast Efficiency	89%	89%	89%	N/A	N/A	N/A
CRI	50	50	50	N/A	N/A	N/A
Correlated Color Temperature (CCT)	3,900	3,900	3,900	N/A	N/A	N/A
Average Lamp Life (thousand hours)	24	24	24	N/A	N/A	N/A
Annual Operating Hours (h/y)	3,687	3,687	3,687	N/A	N/A	N/A
Lamp Price (2022$)	$23.81	$23.10	$28.93	N/A	N/A	N/A
Ballast Price (2022$)	$55.39	$53.75	$64.35	N/A	N/A	N/A
Fixture Price (2022$)	$106.65	$103.49	$101.43	N/A	N/A	N/A
Disposal Cost (2022$)	$1.50	$1.50	$1.50	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$1.51	$1.46	$1.38	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$11.76	$11.41	$9.27	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	N/A	N/A	N/A
Labor System Installation (hours)	2.0	2.0	2.0	N/A	N/A	N/A
Labor Lamp Change (hours)	0.5	0.5	0.5	N/A	N/A	N/A
Total Installed Cost (2022$)	$340.29	$334.78	$326.71	N/A	N/A	N/A
Annual Maintenance Cost (2022$)	$9.82	$9.71	$9.74	N/A	N/A	N/A
Total Installed Cost (2022$/klm)	$21.54	$21.19	$15.56	N/A	N/A	N/A
Annual Maintenance Cost (2022$/klm)	$0.62	$0.61	$0.46	N/A	N/A	N/A

1. Only a typical dataset is provided because these lamps all have similar efficacies.

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Performance and Cost Characteristics » Commercial Metal Halide High-Bay

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	400.0	400.0	400.0	400.0	400.0	400.0
Lamp Lumens	32,000	32,972	42,000	42,000	42,000	42,000
Lamp Efficacy (lm/W)	80.0	82.4	105.0	105.0	105.0	105.0
System Wattage	444.4	444.4	444.4	444.4	444.4	444.4
System Lumens	32,000	32,972	42,000	42,000	42,000	42,000
System Efficacy (lm/W)	72.0	74.2	94.5	94.5	94.5	94.5
Ballast Efficiency	90%	90%	90%	90%	90%	90%
CRI	80	80	80	80	80	80
Correlated Color Temperature (CCT)	4,000	4,000	4,000	4,000	4,000	4,000
Average Lamp Life (thousand hours)	20	20	20	20	20	20
Annual Operating Hours (h/y)	3,760	3,760	3,760	3,760	3,760	3,760
Lamp Price (2022$)	$34.95	$33.91	$42.15	$40.49	$38.51	$36.63
Ballast Price (2022$)	$55.39	$53.75	$64.35	$61.82	$58.80	$55.92
Fixture Price (2022$)	$248.32	$248.32	$248.32	$238.56	$226.90	$215.80
Disposal Cost (2022$)	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
Lamp Cost (2022$/klm)	$1.09	$1.03	$1.00	$0.96	$0.92	$0.87
System (l/b/f) Cost (2022$/klm)	$10.58	$10.19	$8.45	$8.12	$7.72	$7.34
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	2.0	2.0	2.0	2.0	2.0	2.0
Labor Lamp Change (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Total Installed Cost (2022$)	$493.10	$490.43	$486.82	$472.87	$456.21	$440.36
Annual Maintenance Cost (2022$)	$14.11	$13.91	$14.41	$14.10	$13.72	$13.37
Total Installed Cost (2022$/klm)	$15.41	$14.87	$11.59	$11.26	$10.86	$10.48
Annual Maintenance Cost (2022$/klm)	$0.44	$0.42	$0.34	$0.34	$0.33	$0.32

1. Only a typical dataset is provided because these lamps all have similar efficacies.

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Performance and Cost Characteristics » Commercial Sodium Vapor High-Bay

Final

DATA[1]	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	250.0	250.0	250.0	250.0	250.0	250.0
Lamp Lumens	24,300	24,300	28,500	28,500	28,500	28,500
Lamp Efficacy (lm/W)	97.2	97.2	114.0	114.0	114.0	114.0
System Wattage	297.0	296.6	296.6	296.6	296.6	296.6
System Lumens	24,300	24,300	28,500	28,500	28,500	28,500
System Efficacy (lm/W)	81.8	81.9	96.1	96.1	96.1	96.1
Ballast Efficiency	84%	84%	84%	84%	84%	84%
CRI	22	22	22	22	22	22
Correlated Color Temperature (CCT)	2,100	2,100	2,100	2,100	2,100	2,100
Average Lamp Life (thousand hours)	24	24	24	24	24	24
Annual Operating Hours (h/y)	3,614	3,614	3,614	3,614	3,614	3,614
Lamp Price (2022$)	$53.71	$52.12	$20.37	$19.57	$18.61	$17.70
Ballast Price (2022$)	$90.16	$87.49	$90.09	$86.55	$82.32	$78.29
Fixture Price (2022$)	$280.71	$272.39	$266.98	$256.49	$243.95	$232.02
Disposal Cost (2022$)	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
Lamp Cost (2022$/klm)	$2.21	$2.14	$0.71	$0.69	$0.65	$0.62
System (l/b/f) Cost (2022$/klm)	$17.47	$16.95	$13.24	$12.72	$12.10	$11.51
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	2.0	2.0	2.0	2.0	2.0	2.0
Labor Lamp Change (hours)	0.5	0.5	0.5	0.5	0.5	0.5
Total Installed Cost (2022$)	$579.02	$566.44	$509.44	$494.61	$476.88	$460.02
Annual Maintenance Cost (2022$)	$14.13	$13.89	$8.26	$8.14	$8.00	$7.86
Total Installed Cost (2022$/klm)	$23.83	$23.31	$17.88	$17.35	$16.73	$16.14
Annual Maintenance Cost (2022$/klm)	$0.58	$0.57	$0.29	$0.29	$0.28	$0.28

1. Only a typical dataset is provided because these lamps all have similar efficacies.

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Performance and Cost Characteristics » Commercial T5 4xF54 HO High-Bay

Final

DATA[1]	2012	2018	2022		2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
Lamp Lumens	4,850	4,850	4,273	4,750	4,273	4,750	4,273	4,750	4,273	4,750
Lamp Efficacy (lm/W)	89.8	89.8	79.1	88.0	79.1	88.0	79.1	88.0	79.1	88.0
System Wattage	233.8	233.8	233.8	233.8	233.8	233.8	233.8	233.8	233.8	233.8
System Lumens	19,400	19,400	17,092	19,000	17,092	19,000	17,092	19,000	17,092	19,000
System Efficacy (lm/W)	83.0	83.0	73.1	81.3	73.1	81.3	73.1	81.3	73.1	81.3
Ballast Efficiency (BLE)	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
CRI	86	86	86	86	86	86	86	86	86	86
Correlated Color Temperature (CCT)	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100
Average Lamp Life (thousand hours)	24	24	25	25	25	25	25	25	25	25
Annual Operating Hours (h/y)	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042
Lamp Price (2022$)	$8.45	$8.20	$4.70	$13.65	$4.51	$13.11	$4.29	$12.47	$4.08	$11.86
Ballast Price (2022$)	$33.43	$32.44	$32.17	$32.17	$30.91	$30.91	$29.39	$29.39	$27.96	$27.96
Fixture Price (2022$)	$129.23	$125.40	$122.91	$122.91	$118.08	$118.08	$112.31	$112.31	$106.82	$106.82
Disposal Cost (2022$)	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48	$0.48
Lamp Cost (2022$/klm)	$1.74	$1.69	$1.10	$2.87	$1.06	$2.76	$1.00	$2.63	$0.96	$2.50
System (l/b/f) Cost (2022$/klm)	$10.13	$9.83	$10.17	$11.04	$9.77	$10.60	$9.30	$10.08	$8.84	$9.59
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Labor Lamp Change (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total Installed Cost (2022$)	$325.54	$320.47	$291.78	$300.73	$285.50	$294.10	$277.99	$286.17	$270.86	$278.63
Annual Maintenance Cost (2022$)	$12.51	$12.35	$8.68	$14.47	$8.56	$14.12	$8.42	$13.71	$8.29	$13.32
Total Installed Cost (2022$/klm)	$16.78	$16.52	$17.07	$15.83	$16.70	$15.48	$16.26	$15.06	$15.85	$14.66
Annual Maintenance Cost (2022$/klm)	$0.65	$0.64	$0.51	$0.76	$0.50	$0.74	$0.49	$0.72	$0.48	$0.70

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Performance and Cost Characteristics » Commercial LED High-Bay Luminaire

Final

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	212.2	167.0	150.0	137.8	130.0	115.5	109.0	99.4	93.9	87.4	82.5
System Lumens	18,915	18,797	18,500	18,500	18,900	18,500	18,900	18,500	18,900	18,500	18,900
System Efficacy (lm/W)	89.1	112.6	123.3	134.3	145.4	160.2	173.4	186.0	201.4	211.7	229.2
Ballast Efficiency	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	74	78	80	80	80	80	80	80	80	80	80
Correlated Color Temperature (CCT)	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Average Lifetime (thousand hours)	70	67	100	100	100	100	100	100	100	100	100
Annual Operating Hours (h/y)	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042
Lamp or Luminaire Price (2022$)	$2,842.05	$448.43	$177.54	$195.81	$234.20	$162.12	$193.90	$148.87	$178.06	$136.20	$162.90
Ballast Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$150.25	$23.86	$9.60	$10.58	$12.39	$8.76	$10.26	$8.05	$9.42	$7.36	$8.62
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$2,996.49	$602.87	$309.54	$327.81	$366.20	$294.12	$325.90	$280.87	$310.06	$268.20	$294.90
Annual Maintenance Cost (2022$)	$173.01	$36.40	$12.51	$13.25	$14.80	$11.89	$13.17	$11.35	$12.53	$10.84	$11.92
Total Installed Cost (2022$/klm)	$158.42	$32.07	$16.73	$17.72	$19.38	$15.90	$17.24	$15.18	$16.41	$14.50	$15.60
Annual Maintenance Cost (2022$/klm)	$9.15	$1.94	$0.68	$0.72	$0.78	$0.64	$0.70	$0.61	$0.66	$0.59	$0.63

1. N/A because the lamp and fixture are both included in the luminaire.

Refrigeration

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Performance and Cost Characteristics » Commercial Compressor Rack Systems

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)[1]	1,200	1,200	1,200	1,190	930	N/A	1,190	930	1,190	930	1,190	930
Median Store Size (ft^2)	46,500	31,997	35,197	35,197	35,197	N/A	35,197	35,197	35,197	35,197	35,197	35,197
Power Input (kW)	162	155	162	160	125	N/A	160	125	160	125	160	125
Annual Energy Use (MMWh/y)[2]	1,497	1,497	1,305	1,232	1,160	N/A	1,232	1,160	1,232	1,160	1,232	1,160
Indexed Annual Efficiency[3]	1.00	1.00	1.15	1.21	1.29	N/A	1.21	1.29	1.21	1.29	1.21	1.29
Average Life (years)	15	15	15	15	15	N/A	15	15	15	15	15	15
Total Installed Cost (2022$)	$630,000	$630,000	$488,000	$625,000	$630,000	N/A	$625,000	$630,000	$625,000	$630,000	$625,000	$630,000
Total Installed Cost (2022$/kBtu/h)	$525,000	$525,000	$406,667	$525,210	$677,419	N/A	$525,210	$677,419	$525,210	$677,419	$525,210	$677,419
Annual Maintenance Cost (2022$)[4]	$3,400	$3,400	$3,400	$3,400	$3,400	N/A	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400
Annual Maintenance Cost (2022$/kBtu/h)	$2,833	$2,833	$2,833	$2,857	$3,656	N/A	$2,857	$3,656	$2,857	$3,656	$2,857	$3,656

1. The total capacity represents the nominal compressor capacity required for the entire refrigeration system of a typical supermarket. This refrigeration system usually includes two low temperature racks and two medium temperature racks. For 2018, a 1,200 MBtu/h total cooling capacity is based on a 200-ton estimate for total capacity–80 tons for the medium temperature racks and 20 tons for the low temperature racks.
2. Capacity and annual energy consumption for 2022 and beyond are based on market research and Guidehouse estimates.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Maintenance cost includes oil changes, bearing lubrication, filter replacement, and system functionality checks-approximately half a day per rack of labor for technician is assumed.

- Commercial compressor rack systems that serve commercial supermarket display cases and walk-ins consist of a number of parallel-connected compressors located in a separate machine room. By modulating compressor capacity, these integrated systems provide higher efficiency and mechanical longevity.
- Rack integrators generally supply a packaged compressor rack for which much of the necessary piping, insulation, components, and controls are pre-assembled.
- A typical supermarket will have 10 to 20 compressors mounted in racks in the 3-horsepower (hp) to 15-hp size range. Usually, each rack has three to five compressors serve a series of loads with nearly identical evaporator temperature.
- The duty cycle for compressors is usually in the range of 60% to 70%.
- Energy use and capacity for the Reference Case are projected to remain static over the coming decades because commercial compressor racks systems are a mature technology. The Reference Case assumes low R&D efforts because it is an established technology.

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Performance and Cost Characteristics » Commercial Condensers

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)[1]	1,680	1,520	1,440	1,440	1,440	N/A	1,440	1,440	1,440	1,440	1,440	1,440
Median Store Size (ft^2)	46,500	31,997	35,197	35,197	35,197	N/A	35,197	35,197	35,197	35,197	35,197	35,197
Power Input (kW)	25	25	18	18	18	N/A	18	18	18	18	18	18
Annual Energy Use (MMWh/y)	120	120	115	106	86	N/A	106	86	106	86	106	86
Indexed Annual Efficiency[2]	1.00	1.00	1.04	1.13	1.40	N/A	1.13	1.40	1.13	1.40	1.13	1.40
Average Life (years)	10	10	10	10	10	N/A	10	10	10	10	10	10
Total Installed Cost (2022$)	$54,000	$60,000	$54,000	$60,000	$80,000	N/A	$60,000	$80,000	$60,000	$80,000	$60,000	$80,000
Total Installed Cost (2022$/kBtu/h)	$32,143	$39,474	$37,500	$41,667	$55,556	N/A	$41,667	$55,556	$41,667	$55,556	$41,667	$55,556
Annual Maintenance Cost (2022$)[3]	$954	$954	$954	$954	$954	N/A	$954	$954	$954	$954	$954	$954
Annual Maintenance Cost (2022$/kBtu/h)	$0.57	$0.63	$0.66	$0.66	$0.66	N/A	$0.66	$0.66	$0.66	$0.66	$0.66	$0.66

1. Total capacity is the total heat rejected (THR) by condensers comprised of two low temperature condensers (THRL = 240 MBtu/h each, suction temperature= -25°F, condensing temperature-110°F) and two medium temperature condensers (THRM = 520 MBtu/h each, suction temperature = 15°F, condensing temperature = 115°F); ambient temperature = 95°F. (NCI, 2009). For 2022 and beyond, capacity was estimated by Guidehouse.
2. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
3. Maintenance cost includes coil cleaning, leak checking, belt replacement as necessary, and system functionality checks.

- Condensers are designed with multiple methods of cooling: air-cooled, water-cooled, and evaporative. These units can be single-circuit or a multiple circuit.
- Commercial condensers are remotely located, typically installed on the roof of a supermarket.
- For use with parallel compressors in supermarkets, air-cooled units are the most commonly used condensers. This analysis is based on multiple air-cooled condensers connected to a supermarket refrigeration system comprised of two low temperature condensers and two medium temperature condensers.
- Each compressor rack has a dedicated condenser or a separate circuit of a single common condenser. Condenser temperatures of multiple racks are often different.
- The duty cycle for condensers is usually in the range 50%-70%.
- Energy use is projected to remain static over the coming decades because commercial condensers are a mature technology.

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Performance and Cost Characteristics » Commercial Supermarket Display Cases

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	17,623	11,850	11,850	11,850	11,850	N/A	11,850	11,850	11,850	11,850	11,850	11,850
Median Store Size (ft^2)	46,500	31,997	35,197	35,197	35,197	N/A	35,197	35,197	35,197	35,197	35,197	35,197
Case Length (ft)	12	12	12	12	12	N/A	12	12	12	12	12	12
Annual Energy Use (kWh/y)[1,2]	13,497	10,506	10,506	9,771	9,087	N/A	9,771	9,087	9,771	9,087	9,771	9,087
Annual Energy Use / Case Length (kWh/ft)	1,125	876	876	814	757	N/A	814	757	814	757	814	757
Indexed Annual Efficiency[3]	1.00	1.28	1.28	1.38	1.49	N/A	1.38	1.49	1.38	1.49	1.38	1.49
Average Life (years)	10	10	10	10	10	N/A	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$8,510	$10,650	$7,265	$9,500	$10,680	N/A	$9,500	$10,680	$9,500	$10,680	$9,500	$10,680
Total Installed Cost (2022$)	$10,811	$12,650	$9,265	$11,500	$12,680	N/A	$11,500	$12,680	$11,500	$12,680	$11,500	$12,680
Total Installed Cost (2022$/kBtu/h)	613	1,068	782	970	1,070	N/A	970	1,070	970	1,070	970	1,070
Annual Maintenance Cost (2022$)[4]	$940	$940	$940	$940	$940	N/A	$940	$940	$940	$940	$940	$940
Annual Maintenance Cost (2022$/kBtu/h)	$53.34	$79.32	$79.32	$79.32	$79.32	N/A	$79.32	$79.32	$79.32	$79.32	$79.32	$79.32

1. For 2022 and beyond, energy consumption and cost values were estimated using shipment-weighted averages reported in DOE's 2014 CRE Final Rule Technical Support Document (TSD) for equipment commonly used as display cases. DOE's updated conservation standard went into effect in 2017, so units sold in 2018 are assumed to comply with this standard.
2. For consistency with DOE rulemaking practices, Supermarket Display Case Energy Use reported above includes energy use of the compressor racks and condensers. To avoid double counting, do not add Energy Use from the Compressor Rack or Condenser Systems tabs if calculating total energy consumption.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Maintenance cost includes preventative maintenance costs such as cleaning evaporator coils, drain pans, fans, and intake screens as well as lamp replacements and other lighting maintenance activities. After 2012, these values are based on a reported maintenance and repair cost of $220 per unit for preventative maintenance plus approximately $60 per linear foot for additional repair and maintenance.

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Performance and Cost Characteristics » Commercial Supermarket Display Cases

Final

- DOE set federal energy efficiency standards for Commercial Refrigeration Equipment (CRE) in 2009. These standards set maximum daily energy consumption levels, in kilowatt-hours per day, for display cases manufactured sold in the United States on or after January 1, 2012.
- DOE updated its Energy Conservation Standards for Commercial Refrigeration Equipment in 2014 for equipment sold on or after March 27, 2017.
- The table below lists equipment used as supermarket display cases and their corresponding Energy Conservation Standard levels. The maximum allowable daily energy consumption for each equipment class is a linear function of Total Display Area (TDA).

Equipment Description	Standards Equation (2012)	Standards Equation (2017)
Vertical Open Cooler (VOP.RC.M)	0.82xTDA+4.07	0.64xTDA+4.07
Semi-Vertical Open Cooler (SVO.RC.M)	0.83xTDA+3.18	0.66xTDA+3.18
Horizontal Open Cooler (HZO.RC.M)	0.35xTDA+2.88	0.35xTDA+2.88
Transparent-Doored Cooler (VCT.RC.M)	0.22xTDA+1.95	0.15xTDA+1.95
Deli Display Cooler (SOC.RC.M)	0.51xTDA+0.11	0.44xTDA+0.11
Transparent-Doored Freezer (VCT.RC.L)	0.56xTDA+2.61	0.49xTDA+2.61
Horizontal Open Freezer (HZO.RC.L)	0.57xTDA+6.88	0.55xTDA+6.88

- According to CBECS 2018 microdata, the average building size for food sale building type is 31,997.
- Unit energy consumption for 2022 and beyond is estimated using a shipment-weighted average by efficiency level and equipment class, using data in DOE's 2014 CRE Final Rule TSD with updated analysis from Guidehouse in 2016. The equipment classes analyzed are listed in the table on the previous slide.
- Supermarket refrigeration systems consist of refrigerated display cases, condensing units, and centralized compressor racks.
- A typical supermarket display case contains lighting, evaporators, evaporator fans, piping, insulation, valves, and controls.
- The efficiency of supermarket display cases can be increased through the use of improved evaporator coils, larger evaporators, higher efficiency evaporator fan blades, high efficiency doors, LED lighting, and improved insulation.
- Energy use is projected to remain static over the coming decades because supermarket display cases are a mature technology.

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Performance and Cost Characteristics » Commercial Reach-In Refrigerators

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	2,929	2,400	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349
Size (ft^3)	49	49	46	46	46	47	46	46	46	46	46	46
Annual Energy Use (kWh/y)	2,340	2,222	1,935	1,351	810	810	1,351	810	1,351	810	1,351	810
Annual Energy Use / Volume ($kWh/y/ft^3$)[1]	48	45	42	29	18	17	29	18	29	18	29	18
Indexed Annual Efficiency[3]	1.00	1.05	1.21	1.73	2.89	2.89	1.73	2.89	1.73	2.89	1.73	2.89
Average Life (years)	10	10	10	10	10	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$2,624	$2,403	$2,728	$2,780	$3,021	$3,021	$2,780	$3,021	$2,780	$3,021	$2,780	$3,021
Total Installed Cost (2022$)[4]	$3,454	$3,282	$3,591	$3,643	$3,884	$3,884	$3,643	$3,884	$3,643	$3,884	$3,643	$3,884
Total Installed Cost (2022$/kBtu/h)	$1,179	$1,368	$1,529	$1,551	$1,654	$1,654	$1,551	$1,654	$1,551	$1,654	$1,551	$1,654
Annual Maintenance Cost (2022$)[5]	$185	$185	$185	$185	$185	$186	$185	$185	$185	$185	$185	$185
Annual Maintenance Cost (2022$/kBtu/h)	$63	$77	$79	$79	$79	$79	$79	$79	$79	$79	$79	$79

1. EPACT 2005 energy standards went into effect in 2010. 2022 low efficiency cost and energy consumption values are based on minimum compliance with this standard. Unless otherwise noted, all other cases are based on shipment-weighted averages solid- and transparent-doored units reported in the 2014 CRE TSD. DOE's updated Energy Conservation standards went into effect in 2017; therefore, compliance with this standard is assumed for 2022 and beyond.
2. The ENERGY STAR category is based on a shipment weighted average of solid- and transparent-doored units that are minimally compliant with ENERGY STAR v3, effective October 1, 2014. Units compliant with ENERGY STAR are found to be the most efficient reach-in refrigeration equipment on the market in 2022.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 is based on NCI 2009 report that assumes a cost of $863. Installation cost for 2022 and beyond is based DOE's 2014 CRE Final Rule and additional analysis by Guidehouse, which assumes an installation cost of $878 for self-contained equipment.
5. Maintenance costs after 2012 are based on DOE's CRE 2014 Final Rule TSD, which reports $35 annual preventative maintenance, per unit, per year, plus approximately $40 per linear foot, per year of additional repair and maintenance costs for the units characterized.

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Performance and Cost Characteristics » Commercial Reach-In Refrigerators

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- The Energy Policy Act of 2005 (EPACT 2005) set maximum daily energy consumption levels, in kilowatt-hours per day, for commercial reach-in refrigerators that went into effect on January 1, 2010. The daily energy consumption is based on the volume of the unit (V) in ft^3.
- In 2014, DOE updated its energy conservation standards for reach-in refrigerators, effective March 27, 2017. Both standards are reported in the table below.

Equipment Class	EPCA Standard Level (2010)	DOE Standard Level (2017)
Solid Door (VCS.SC.M)	0.10xV+2.04	0.05xV + 1.36
Glass Door (VCT.SC.M)	0.12xV+3.34	0.1xV+0.86

- In 2013, EPA updated its ENERGY STAR specifications for reach-in refrigerators, effective March 27, 2017. These standards are also based on the refrigerated volume of the unit.

Reach-In Refrigerator Size	0 < V < 15	15 ≤ V < 30	30 ≤ V < 50	50 ≤ V
Solid Door (VCS.SC.M)	0.022xV+0.97	0.066xV+0.31	0.04xV+1.09	0.024xV+1.89
Glass Door (VCT.SC.M)	0.095xV+0.445	0.05xV+1.12	0.076xV+0.034	0.105xV-1.111

- Unit energy consumption for 2012 and beyond was estimated based on shipment-weighted averages by efficiency level and equipment class for 49 ft3 VCS.SC.M and VCT.SC.M units reported in DOE's 2014 CRE Final Rule TSD with updated analysis from Guidehouse in 2016. These units were estimated to comprise approximately 85% and 15% of total reach-in refrigerator shipments, respectively.
- The efficiency of commercial reach-in refrigerators can be increased through the use of efficient compressors, efficient evaporator fans, efficient condenser fans, electric defrost, and more efficient lighting.
- For this referenced scenario, energy use is projected to remain static over the coming decades because reach-in refrigerators are a mature technology.

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Performance and Cost Characteristics » Commercial Reach-In Freezers

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	4,341	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340
Size (ft^3)	49	49	49	49	49	49	49	49	49	49	49	49
Annual Energy Use (kWh/y)[1]	6,023	5,585	5,585	4,847	4,110	4,110	4,847	4,110	4,847	4,110	4,847	4,110
Annual Energy Use / Volume ($kWh/y/ft^3$)	123	114	114	99	84	84	99	84	99	84	99	84
Indexed Annual Efficiency[3]	1.00	1.08	1.08	1.24	1.47	1.47	1.24	1.47	1.24	1.47	1.24	1.47
Average Life (years)	10	10	10	10	10	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$2,886	$2,886	$2,886	$3,175	$3,493	$3,493	$3,175	$3,493	$3,175	$3,493	$3,175	$3,493
Total Installed Cost (2022$)[4]	$3,749	$3,749	$3,749	$4,125	$4,443	$4,443	$4,125	$4,443	$4,125	$4,443	$4,125	$4,443
Total Installed Cost (2022$/kBtu/h)	$864	$864	$864	$950	$1,024	$1,024	$950	$1,024	$950	$1,024	$950	$1,024
Annual Maintenance Cost (2022$)[5]	$181	$181	$181	$181	$181	$181	$181	$181	$181	$181	$181	$181
Annual Maintenance Cost (2022$/kBtu/h)	$41.70	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71

1. A 49 ft^3 unit was characterized, because it was the representative size selected for DOE's rulemaking analysis.
2. The ENERGY STAR category was based on a solid-doored unit that is minimally compliant with ENERGY STAR v3, effective October 1, 2014.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 and 2018 is based on DOE's on-going CRE rulemaking, which assumes a cost of $863 for self-contained equipment and $950 for 2022 and beyond based on analysis from Guidehouse.
5. Maintenance costs are calculated based on a $35 per unit annual preventative maintenance cost, plus an additional $45 per linear foot repair and maintenance cost estimated based on values reported in the CRE TSD.

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Performance and Cost Characteristics » Commercial Reach-In Freezers

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- EPACT 2005 set maximum daily energy consumption levels, in kilowatt-hours per day, for commercial reach-in freezers that went into effect on January 1, 2010. The daily energy consumption is based on the volume of the unit (V) in ft^3.
- In March of 2017, DOE updated its energy conservation standards for commercial refrigeration equipment, including reach-in freezers. Both the EPCA and DOE standards are reported in the table below.

Equipment Class	EPCA (2010)	DOE Standard Level (2017)
Solid Door (VCS.SC.L)	0.4xV+1.38	0.22xV+1.38
Transparent Door (VCT.SC.L)	0.75xV+4.10	0.29xV+2.95

- In 2013, EPA updated its ENERGY STAR specifications for reach-in freezers, effective March 27, 2017. These standards are also based on the refrigerated volume of the unit.

Reach-In Freezer Size	0 < V < 15	15 ≤ V < 30	30 ≤ V < 50	50 ≤ V
Solid Door (VCS.SC.L)	0.21xV+0.9	0.12xV+2.248	0.285xV-2.703	0.142xV+4.445
Glass Door (VCT.SC.L)	0.232xV+2.36	0.232xV+2.36	0.232xV+2.36	0.232xV+2.36

- The commercial reach-in freezer characterized in this report, which is the typical unit according to DOE's 2014 CRE rulemaking, is a 49 cubic ft. solid two-door unit with a nominal compressor size of 4,341 Btu/h.
- The efficiency of commercial reach-in freezers can be increased through the use of efficient compressors, efficient evaporator fans, efficient condenser fans, electric defrost, and more efficient lighting.
- For this referenced scenario, energy use is projected to remain static over the coming decades because reach-in freezers are a mature technology.

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Performance and Cost Characteristics » Commercial Walk-In Refrigerators

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)[1]	37,820	39,422	41,024	41,024	41,024	N/A	41,024	41,024	41,024	41,024	41,024	41,024
Size (ft^2)	305	240	240	240	240	N/A	240	240	240	240	240	240
Annual Energy Use (kWh/y)[2]	30,689	20,040	17,600	16,200	14,800	N/A	16,200	14,800	16,200	14,800	16,200	14,800
Annual Energy Use / Area ($kWh/ft^2/y$)	101	84	73	68	62	N/A	68	62	68	62	68	62
Indexed Annual Efficiency[3]	1.00	1.53	1.74	1.89	2.07	N/A	1.89	2.07	1.89	2.07	1.89	2.07
Insulated Box Average Life (years)	12	12	12	12	12	N/A	12	12	12	12	12	12
Compressor Average Life (years)	10	10	10	10	10	N/A	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$23,598	$19,847	$16,050	$19,847	$23,644	N/A	$16,050	$23,644	$16,050	$23,644	$16,050	$23,644
Total Installed Cost (2022$)[4]	$27,012	$23,897	$20,100	$23,897	$27,694	N/A	$20,100	$27,694	$20,100	$27,694	$20,100	$27,694
Total Installed Cost (2022$/kBtu/h)	$714	$606	$490	$583	$675	N/A	$490	$675	$490	$675	$490	$675
Annual Maintenance Cost (2022$)[5]	$716	$740	$740	$740	$740	N/A	$740	$740	$740	$740	$740	$740
Annual Maintenance Cost (2022$/kBtu/h)	$18.93	$18.77	$18.04	$18.04	$18.04	N/A	$18.04	$18.04	$18.04	$18.04	$18.04	$18.04

1. Assumes medium temperature units are refrigerators.
2. Average unit energy consumption was adapted from the DOE CRE 2016 report by assuming electronically commutated motor (ECM) evaporator fan motors are required for Energy Policy & Conservation Act (EPCA) compliance, as well as ECM condenser fan motors.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 and beyond is based on DOE's Walk-In TSD.
5. Maintenance cost includes checking and maintaining refrigerant charge levels, checking settings, and cleaning heat exchanger coils.

- For 2012 and beyond, the unit characterized was a walk-in storage cooler, based on DOE's WICF TSD.
- A typical walk-in refrigerator includes:
  - insulated floor and wall panels
  - merchandising doors, shelving, and lighting (not included in cost estimate)
  - semi-hermetic reciprocating compressor
  - refrigerant (R404A)
  - condenser
  - evaporator
- Energy consumption is assumed to scale with the AWEF (Annual Walk-in Energy Factor), defined as the ratio of total heat removed from the refrigerated volume per year to the total electrical energy input of refrigeration systems over the same time period.
- The installation cost consists of freight and delivery costs in addition to on-site assembly.

The Energy Independence and Security Act (EISA) of 2007 included prescriptive standards for walk-in refrigerators (coolers) that went into effect in 2009. These prescriptive standards, which are included in the analysis for all units for 2012 and beyond, state that all walk-in refrigerators manufactured after January 1, 2009, must:

- For 2012 and beyond
- have automatic door closers
- have strip doors, spring hinged doors, or other method of minimizing infiltration when doors are open
- contain wall, ceiling, and door insulation of at least R–25, except for glazed portions of doors and structural members
- use electronically commutated motors or three-phase motors (for evaporator fan motors of under 1 horsepower and less than 460 volts)
- use electronically commutated motors, permanent split capacitor-type motors, or three-phase motors (for condenser fan motors of under 1 horsepower)
- use light sources with an efficacy of 40 lumens per watt or more, including ballast losses (if any), except that light sources with an efficacy of 40 lumens per watt or less, including ballast losses (if any), may be used in conjunction with a timer or device that turns off the lights within 15 minutes of when the walk-in refrigerator is not occupied by people.

In 2014, DOE updated its energy conservation standards for walk-in coolers and freezers. Minimum AWEF (Annual Walk-In Energy Factor) was set for refrigeration systems, as well as upper limits on energy consumption attributable to passage, freight, and display doors. DOE elected not to set new standards for the R-value of Walk-In Panels.

ENERGY CONSERVATION STANDARDS FOR WALK-IN COOLERS AND WALK-IN FREEZERS

Class descriptor	Class	Standard level
Refrigeration Systems Minimum AWEF (Btu/W-h)		
Dedicated Condensing, Medium Temperature, Indoor System, <9,000 Btu/h Capacity	DC.M.I, <9,000	5.61
Dedicated Condensing, Medium Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.M.I, ≥9,000	5.61
Dedicated Condensing, Medium Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.M.O, <9,000	7.60
Dedicated Condensing, Medium Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.M.O,≥9,000	7.60
Dedicated Condensing, Low Temperature, Indoor System, <9,000 Btu/h Capacity	DC.L.I, <9,000	$5.93 \cdot 10^{W5} \cdot Q + 2.33$
Dedicated Condensing, Low Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.L.I, ≥9,000	3.10
Dedicated Condensing, Low Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.L.O, <9,000	$2.30 \cdot 10^{W4} \cdot Q + 2.73$
Dedicated Condensing, Low Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.L.O, ≥9,000	4.79
Multiplex Condensing, Medium Temperature	MC.M	10.89
Multiplex Condensing, Low Temperature	MC.L	6.57
Panels Minimum R-value (h-ft2-°F/Btu)		
Structural Panel, Medium Temperature	SP.M	25
Structural Panel, Low Temperature	SP.L	32
Floor Panel, Low Temperature	FP.L	28
Non-Display Doors Maximum energy consumption (kWh/day) **		
Passage Door, Medium Temperature	PD.M	$0.05 \cdot A_{nd} + 1.7$
Passage Door, Low Temperature	PD.L	$0.14 \cdot A_{nd} + 4.8$
Freight Door, Medium Temperature	FD.M	$0.04 \cdot A_{nd} + 1.9$
Freight Door, Low Temperature	FD.L	$0.12 \cdot A_{nd} + 5.6$
Display Doors Maximum Energy Consumption (kWh/day) †		
Display Door, Medium Temperature	DD.M	$0.04 \cdot A_{dd} + 0.41$
Display Door, Low Temperature	DD.L	$0.15 \cdot A_{dd} + 0.29$

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Performance and Cost Characteristics » Commercial Walk-In Freezers

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	22,114	23,500	23,500	23,500	23,500	N/A	23,500	23,500	23,500	23,500	23,500	23,500
Size (ft^2) [1]	172	161	161	161	161	N/A	161	161	161	161	161	161
Annual Energy Use (kWh/y)[2]	22,862	22,000	22,000	20,460	19,028	N/A	20,460	19,028	20,460	19,028	20,460	19,028
Annual Energy Use / Area ($kWh/ft^2/y$)	133	124	124	115	107	N/A	115	107	115	107	115	107
Indexed Annual Efficiency[3]	1.00	1.04	1.04	1.12	1.20	N/A	1.12	1.20	1.12	1.20	1.12	1.20
Insulated Box Average Life (years)	12	12	12	12	12	N/A	12	12	12	12	12	12
Compressor Average Life (years)	10	10	10	10	10	N/A	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$22,008	$21,950	$21,950	$22,850	$23,750	N/A	$22,850	$23,750	$22,850	$23,750	$22,850	$23,750
Total Installed Cost (2022$)[4]	$24,058	$23,950	$23,950	$24,850	$25,750	N/A	$24,850	$25,750	$24,850	$25,750	$24,850	$25,750
Total Installed Cost (2022$/kBtu/h)	$1,088	$1,019	$1,019	$1,057	$1,096	N/A	$1,057	$1,096	$1,057	$1,096	$1,057	$1,096
Annual Maintenance Cost (2022$)[5]	$741	$741	$741	$741	$741	N/A	$741	$741	$741	$741	$741	$741
Annual Maintenance Cost (2022$/kBtu/h)	$33.51	$31.53	$31.53	$31.53	$31.53	N/A	$31.53	$31.53	$31.53	$31.53	$31.53	$31.53

1. Based on DOE's 2014 WICF Final Rule TSD and additional analysis by Guidehouse, the average floor area for a walk-in storage freezer as 161 ft^2.
2. EISA 2007 includes prescriptive standards for walk-in freezers that went into effect in 2009. All units for 2012 and beyond include these prescriptive standards. Units for 2022 and beyond are characterized using data from DOE's 2014 WICF rulemaking. All units for 2022 and beyond are assumed to comply with this standard.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 and beyond is based on DOE's WICF TSD and additional analysis by Guidehouse.
5. Maintenance cost includes checking and maintaining refrigerant charge levels, checking settings, and cleaning heat exchanger coils.

- The commercial walk-in freezer characterized in this report is a walk-in storage freezer with an area of 161 ft^2.
- A typical walk-in freezer includes:
  - insulated floor, door, and wall panels
  - semi-hermetic reciprocating compressor
  - refrigerant (R404A)
  - condenser
  - evaporator
- Energy consumption is assumed to scale with the AWEF (Annual Walk-in Energy Factor), defined as the ratio of total heat removed from the refrigerated volume per year to the total electrical energy input of refrigeration systems over the same time period.
- The installation cost consists of freight and delivery costs in addition to on-site assembly.

EISA 2007 included prescriptive standards for walk-in freezers that went into effect in 2009. These prescriptive standards, which are included in all units for 2011 and beyond, state that all walk-in freezers manufactured after January 1, 2009, must:

- have automatic door closers
- have strip doors, spring hinged doors, or other method of minimizing infiltration when doors are open
- contain wall, ceiling, and door insulation of at least R–32, except for glazed portions of doors and structural members
- contain floor insulation of at least R–28
- use electronically commutated motors or three-phase motors (for evaporator fan motors of under 1 horsepower and less than 460 volts)
- use electronically commutated motors, permanent split capacitor-type motors, or three-phase motors (for condenser fan motors of under 1 horsepower)
- use light sources with an efficacy of 40 lumens per watt or more, including ballast losses (if any), except that light sources with an efficacy of 40 lumens per watt or less, including ballast losses (if any), may be used in conjunction with a timer or device that turns off the lights within 15 minutes of when the walk-in freezer is not occupied by people.

In 2014, DOE updated its energy conservation standards for walk-in coolers and freezers. Minimum AWEF (Annual Walk-in Energy Factor) was set for refrigeration systems, as well as upper limits on energy consumption attributable to passage, freight, and display doors. DOE elected not to set new standards for the R-value of Walk-in Panels.

ENERGY CONSERVATION STANDARDS FOR WALK-IN COOLERS AND WALK-IN FREEZERS

Class descriptor	Class	Standard level
Refrigeration Systems Minimum AWEF (Btu/W-h)		
Dedicated Condensing, Medium Temperature, Indoor System, <9,000 Btu/h Capacity	DC.M.I, <9,000	5.61
Dedicated Condensing, Medium Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.M.I, ≥9,000	5.61
Dedicated Condensing, Medium Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.M.O, <9,000	7.60
Dedicated Condensing, Medium Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.M.O,≥9,000	7.60
Dedicated Condensing, Low Temperature, Indoor System, <9,000 Btu/h Capacity	DC.L.I, <9,000	$5.93 \cdot 10^{W5} \cdot Q + 2.33$
Dedicated Condensing, Low Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.L.I, ≥9,000	3.10
Dedicated Condensing, Low Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.L.O, <9,000	$2.30 \cdot 10^{W4} \cdot Q + 2.73$
Dedicated Condensing, Low Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.L.O, ≥9,000	4.79
Multiplex Condensing, Medium Temperature	MC.M	10.89
Multiplex Condensing, Low Temperature	MC.L	6.57
Panels Minimum R-value (h-ft2-°F/Btu)		
Structural Panel, Medium Temperature	SP.M	25
Structural Panel, Low Temperature	SP.L	32
Floor Panel, Low Temperature	FP.L	28
Non-Display Doors Maximum energy consumption (kWh/day) **		
Passage Door, Medium Temperature	PD.M	$0.05 \cdot A_{nd} + 1.7$
Passage Door, Low Temperature	PD.L	$0.14 \cdot A_{nd} + 4.8$
Freight Door, Medium Temperature	FD.M	$0.04 \cdot A_{nd} + 1.9$
Freight Door, Low Temperature	FD.L	$0.12 \cdot A_{nd} + 5.6$
Display Doors Maximum Energy Consumption (kWh/day) †		
Display Door, Medium Temperature	DD.M	$0.04 \cdot A_{dd} + 0.41$
Display Door, Low Temperature	DD.L	$0.15 \cdot A_{dd} + 0.29$

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Performance and Cost Characteristics » Commercial Ice Machines

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DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[6]	Typical	High	Typical	High	Typical	High
Output (pounds [lbs] per day)[1]	300	641	700	700	700	700	700	700	700	700	700	700
Cooling Capacity (Btu/h)[2]	1963	4194	4580	4580	4580	4580	4580	4580	4580	4580	4580	4580
Water Use per Hundred Pounds (gal/hundred lbs)[3]	20	25	25	20	15	15	20	15	20	15	20	15
Energy Use per Hundred Pounds (kWh/hundred lbs)	7.7	7.5	7.1	5.8	4.8	4.8	5.8	4.8	5.8	4.8	5.8	4.8
Annual Energy Use (kWh/y)[4]	3,185	2,502	1,675	1,478	1,190	1,190	1,478	1,190	1,478	1,190	1,478	1,190
Indexed Annual Efficiency[5]	1.00	1.27	1.90	2.15	2.68	2.68	2.15	2.68	2.15	2.68	2.15	2.68
Average Life (years)	8.0	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Retail Equipment Cost (2022$)	$2,146	$2,616	$2,946	$3,020	$3,368	$3,368	$3,020	$3,368	$3,020	$3,368	$3,020	$3,368
Total Installed Cost (with Bin)	$2,441	$3,626	$3,276	$3,350	$3,737	$3,737	$3,350	$3,737	$3,350	$3,737	$3,350	$3,737
Total Installed Cost (2022$/kBtu/h)	$1,244	$865	$715	$732	$816	$816	$732	$816	$732	$816	$732	$816
Annual Maintenance Cost (2022$)[7]	$826	$826	$800	$800	$800	$800	$800	$800	$800	$800	$800	$800
Annual Maintenance Cost (2022$/kBtu/h)	$421	$197	$175	$175	$175	$175	$175	$175	$175	$175	$175	$175

1. Based on the average output from the Compliance Certification Database and values within 2022 Automatic Commercial Ice Maker (ACIM) TSD.
2. Defined as the average heat load to remove the latent and sensible heat required to freeze the daily output capacity of ice.
3. Water use refers to potable water.
4. EPACT 2005 energy standards went into effect in 2010. The 2015 low values are based on this standard. In 2014, DOE set new standards for commercial ice machines, with compliance required by 2018. The unit characterized for 2012 and beyond uses data from this rulemaking. All units for 2020 and beyond are assumed to comply with the updated standard.
5. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
6. The ENERGY STAR category is based on minimum compliance with the ENERGY STAR v3.0 standard, which went into effect on January 28, 2018. According to this analysis, ENERGY STAR certification is typical for the small air-cooled ice-making head (IMH) unit characterized.
7. Maintenance cost is based on the average cost of equipment within the 700 lb/day output range and includes cleaning and maintaining refrigerant levels, replacing filters, checking water distribution lines for leaks, cleaning, sanitizing, and descaling the bin and water system. Maintenance cost decreases as the size of the ice machine (i.e. output) decreases.

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Performance and Cost Characteristics » Commercial Ice Machines

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- Commercial ice machines are typically integrated with an insulated ice storage bin or mounted on top of a separate storage bin. The retail equipment cost includes the ice making head and the integrated storage bin. Commercial ice machine condensers are either air-cooled or water-cooled. Approximately 90% of all units are the air-cooled type.
- Commercial ice machine maintenance includes periodic cleaning (every 2 to 6 weeks) to remove lime and scale and sanitizing to kill bacteria. Some ice machines are self-cleaning/sanitizing.
- ENERGY STAR® updated its maximum energy consumption levels, in kilowatt-hours per 100 pounds of ice, for air-cooled ice machines that went into effect on January 28, 2018. These efficiency levels are based on the harvest rate, in pounds per 24 hours. (H). Water-cooled ice machines are not eligible for ENERGY STAR certification.

ENERGY STAR Requirements for Air-Cooled Batch-Type Ice Makers			
Equipment Type	Applicable Ice Harvest Rate Range (lbs of ice/24 hrs)	Energy Consumption Rate (kWh/100 lbs ice)	Potable Water Use (gal/hundred lbs ice)
IMH	$200 \le H \le 1600$	$\le 37.72 * H^{-0.298}$	≤ 20.0
RCU	$400 \le H \le 1600$	$\le 22.95 * H^{-0.258} + 1.00$	≤ 20.0
	$1600 \le H \le 4000$	$\le -0.00011 * H + 4.60$	≤ 20.0
SCU	$50 \le H \le 450$	$\le 48.66 * H^{-0.326} + 0.08$	≤ 25.0

ENERGY STAR Requirements for Air-Cooled Continuous-Type Ice Makers		
Equipment Type	Energy Consumption Rate (kWh/hundred lbs ice)	Potable Water Use (gal/hundred lbs ice)
IMH	$\le 9.18 * H^{-0.057}$	≤ 15.0
RCU	$\le 6.00 * H^{-0.162} + 3.50$	≤ 15.0
SCU	$\le 59.45 * H^{-0.349} + 0.08$	≤ 15.0

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EPACT 2005 issued standard levels for commercial ice machines with capacities between 50 pounds and 2500 pounds per 24-hour period that are manufactured or sold in the United States on or after January 1, 2010. The energy consumption is based on the harvest rate in pounds per 24 hours (H). In 2015, DOE finalized new standards for ACIMs extending coverage to flake, nugget, and tube-type machines and to capacities up to 4,000 pounds per 24 hours.

Equipment Type	Type of Cooling	Harvest Rate (lbs ice/24 hrs)	Maximum Energy Use (kWh/hundred lbs ice)	Maximum Condenser Water Use (gal/hundred lbs ice)
Ice Making Head	Water	<500	7.80-0.0055 H	200-0.022 H
		≥500 and <1,436	5.58-0.0011 H	200-0.022 H
		≥1,436	4.0	200-0.022 H
	Air	<450	10.26-0.0086 H	Not Applicable
		≥450	6.89-0.0011 H	Not Applicable
Remote Condensing (but not remote compressor)	Air	<1,000	8.85-0.0038 H	Not Applicable
		≥1,000	5.10	Not Applicable
Remote Condensing and Remote Compressor	Air	<934	8.85-0.0038 H	Not Applicable
		≥934	5.3	Not Applicable
Self Contained	Water	<200	11.40-0.019 H	191-0.0315 H
		≥200	7.60	191-0.0315 H
	Air	<175	18.0-0.0469 H	Not Applicable
		≥175	9.80	Not Applicable

Water use is for the condenser only and does not include potable water used to make ice.

2014 DOE Standards

Energy Conservation Standards for Batch-Type Automatic Commercial Ice Makers
Effective January 2018

Equipment Type	Type of Cooling	Harvest Rate lb ice/24 hours	Maximum Energy Use kWh/100 lb ice*	Maximum Condenser Water Use gal/100 lb ice**
Ice-Making Head	Water	<300	6.88 - 0.0055H	200 - 0.022H
		300 and <850	5.80 - 0.00191H	200 - 0.022H
		850 and <1,500	4.42 - 0.00028H	200 - 0.022H
		1500 and <2,500	4.0	200 - 0.022H
		2500 and <4,000	4.0	145
Ice-Making Head	Air	<300	10 - 0.01233H	Not Applicable
		300 and <800	7.05 - 0.0025H	Not Applicable
		800 and <1500	5.55 - 0.00063H	Not Applicable
		1500 and <4,000	4.61	Not Applicable
Remote Condensing (but not remote compressor)	Air	50 and <1,000	7.97 - 0.00342H	Not Applicable
		1,000 and <4,000	4.55	Not Applicable
Remote Condensing and Remote Compressor	Air	<942	7.97 - 0.00342H	Not Applicable
		942 and <4,000	4.75	Not Applicable
Self-Contained	Water	<200	9.5 - 0.019H	191 - 0.0315H
		200 and <2,500	5.7	191 - 0.0315H
		2500 and <4,000	5.7	112
Self-Contained	Air	<110	14.79 - 0.0469H	Not Applicable
		110 and <200	12.42 - 0.02533H	Not Applicable
		200 and <4,000	7.35	Not Applicable

Energy Conservation Standards for Continuous-Type Automatic Commercial Ice Makers
Effective January 2018

Equipment Type	Type of Cooling	Harvest Rate lb ice/24 hours	Maximum Energy Use kWh/100 lb ice*	Maximum Condenser Water Use gal/100 lb ice**
Ice-Making Head	Water	<801	6.48 - 0.00267H	180 - 0.0198H
		801 and <2,500	4.34	180 - 0.0198H
		2,500 and <4,000	4.34	130.5
Ice-Making Head	Air	<310	9.19 - 0.00629H	Not Applicable
		310 and <820	8.23 - 0.0032H	Not Applicable
		820 and <4,000	5.61	Not Applicable
Remote Condensing (but not remote compressor)	Air	<800	9.7 - 0.0058H	Not Applicable
		800 and <4,000	5.06	Not Applicable
Remote Condensing and Remote Compressor	Air	<800	9.9 - 0.0058H	Not Applicable
		800 and <4,000	5.26	Not Applicable
Self-Contained	Water	<900	7.6 - 0.00302H	153 - 0.0252H
		900 and <2,500	4.88	153 - 0.0252H
		2500 and <4,000	4.88	90
Self-Contained	Air	<200	14.22 - 0.03H	Not Applicable
		200 and <700	9.47 - 0.00624H	Not Applicable
		700 and <4,000	5.1	Not Applicable

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Performance and Cost Characteristics » Commercial Beverage Merchandisers

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	4,689	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700
Size (ft^3)	27	27	27	27	27	27	27	27	27	27	27	27
Annual Energy Use (kWh/y)	1,829	1,635	1,380	1,141	902	902	1,141	902	1,141	902	1,141	902
Annual Energy Use / Volume ($kWh/ft^3/y$)[1]	68	73	55	35	26	26	35	26	35	26	35	26
Indexed Annual Efficiency[3]	1.00	1.12	1.33	1.60	2.03	2.03	1.60	2.03	1.60	2.03	1.60	2.03
Average Life (years)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Retail Equipment Cost (2022$)	$2,382	$2,051	$1,710	$2,762	$3,332	$3,332	$2,762	$3,332	$2,762	$3,332	$2,762	$3,332
Total Installed Cost (2022$)[4]	$2,382	$2,051	$1,710	$2,762	$3,332	$3,332	$2,762	$3,332	$2,762	$3,332	$2,762	$3,332
Total Installed Cost (2022$/kBtu/h)	$508	$436	$364	$588	$709	$709	$588	$709	$588	$709	$588	$709
Annual Maintenance Cost (2022$)	$108	$108	$95	$95	$95	$95	$95	$95	$95	$95	$95	$95
Annual Maintenance Cost (2022$/kBtu/h)	$23.03	$22.98	$20.21	$20.21	$20.11	$20.11	$20.21	$20.11	$20.21	$20.11	$20.21	$20.11

1. EPACT 2005 energy conservation standards went into effect in 2010. In 2015, DOE updated its energy conservation standards for commercial refrigeration equipment, including transparent-doored refrigerators with pull-down capability. Compliance with this standard is required by 2017. Units characterized for 2018 and beyond use data reported in this rulemaking's TSD. Units sold in 2022 and beyond are assumed to comply with this updated standard.
2. The ENERGY STAR category characterizes a unit that is compliant with ENERGY STAR v4, effective March 2017. This standard does not separately define units with pull-down capability.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Beverage merchandisers are shipped ready to be plugged in, so installation costs are assumed to be negligible.

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Performance and Cost Characteristics » Commercial Beverage Merchandisers

Final

- EPACT 2005 sets maximum daily energy consumption levels, in kilowatt-hours per day, for commercial refrigerators with transparent doors and self-contained condensing unit designed for pull-down temperature applications (i.e., beverage merchandisers) and went into effect on January 1, 2010.
- In 2014, DOE updated its energy consumption standards for commercial refrigeration equipment, including beverage merchandisers, effective March 27, 2015. Both the DOE and EPCA standards are reported below.

Equipment Type	EPCA (2010)	DOE Standards (2017)
Beverage Merchandisers (PD.SC.M)	0.126xV + 3.51	0.11xV+0.81

- In 2013, EPA updated its ENERGY STAR specifications for glass-doored commercial refrigerators, which can be used as beverage merchandisers, effective October 1, 2014. These standards are also based on the volume of the unit (V). Note that ENERGY STAR does not have a separate equipment class for units with pull-down capability.

Beverage Merchandiser Size	0 < V < 15	15 ≤ V < 30	30 ≤ V < 50	50 ≤ V
Glass Door	0.118*V + 1.382	≤ 0.140*V + 1.050	≤ 0.088*V + 2.625	≤ 0.110*V + 1.500

- The beverage merchandiser characterized in this report, which is the typical unit according to DOE's 2014 CRE rulemaking and additional analysis by Guidehouse, is a 27 cubic foot cooler with a single hinged, transparent door, bright lighting, and shelving with a nominal compressor size of 4,700 Btu/h.
- The efficiency of beverage merchandisers can be increased through the use of more efficient compressors, fluorescent lighting with electronic ballasts, LED lighting, and improved insulation.
- For the Reference Case, beverage merchandisers are assumed to be mature technologies with few technology advancements in the coming years that would dramatically improve the efficiency.

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Performance and Cost Characteristics » Commercial Refrigerated Vending Machines

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	1,810	1,707	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810
Can Capacity	470	500	500	500	500	500	500	500	500	500	500	500
Size (ft^3)	26	35	35	35	35	35	35	35	35	35	35	35
Annual Energy Use (kWh/y)[1]	1,632	1,550	1,550	1,531	1,443	1,443	1,531	1,443	1,531	1,443	1,531	1,443
Annual Energy Use / Volume ($kWh/ft^3/y$)	63	44	44	44	41	41	44	41	44	41	44	41
Indexed Annual Efficiency[3]	1.00	1.05	1.05	1.07	1.13	1.13	1.07	1.13	1.07	1.13	1.07	1.13
Average Life (years)	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Retail Equipment Cost (2022$)	$3,209	$2,553	$3,059	$3,272	$3,520	$3,520	$3,272	$3,520	$3,272	$3,520	$3,272	$3,520
Total Installed Cost (2022$)	$3,320	$2,705	$3,276	$3,489	$3,737	$3,737	$3,489	$3,737	$3,489	$3,737	$3,489	$3,737
Total Installed Cost (2022$/kBtu/h)	$1,834	$1,585	$1,810	$1,928	$2,065	$2,065	$1,928	$2,065	$1,928	$2,065	$1,928	$2,065
Annual Maintenance Cost (2022$)[4]	$270	$270	$333	$333	$333	$333	$333	$333	$333	$333	$333	$333
Annual Maintenance Cost (2022$/kBtu/h)	$149	$149	$184	$184	$184	$184	$184	$184	$184	$184	$184	$184

1. Energy use for 2018 and beyond is estimated based on DOE's 2020 BVM Final Rule and the 2022 Compliance Certification Database.
2. The ENERGY STAR category assumes units are compliant with the ENERGY STAR v4 standard because combination units are currently not separately defined by ENERGY STAR. This standard went into effect on April 29, 2020. Our analysis finds ENERGY STAR certified equipment to be the most efficient currently available on the market.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Maintenance cost includes preventative maintenance costs such as checking and maintaining refrigerant charge levels, cleaning heat exchanger coils, and an annualized cost for refurbishments/remanufacturing.

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Performance and Cost Characteristics » Commercial Refrigerated Vending Machines

Final

- DOE set federal energy efficiency standards for refrigerated vending machines. These standards set maximum daily energy consumption levels, in kilowatt-hours per day, for commercial refrigerated vending machines manufactured or sold in the United States on or after August 31, 2012. The daily energy consumption is based on the volume of the unit (V).
- In December 2015, DOE updated its energy conservation standards for beverage vending machines and defined two new product classes for combination vending machines. The energy conservation standard remains the same in the updated 2022 technical support document for vending machines. Compliance with these standards was required by 2019. For this analysis, compliance with these updated standards is assumed for equipment sold in 2022 and beyond. The updated standards and DOE equipment definitions are listed in the table below.

Equipment Type	Maximum Daily Energy Consumption
Class A (Transparent-Front)	MDEC= 0.052 × V + 2.43
Class B (Solid-Front)	MDEC = 0.052 × V + 2.20
Combination A	MDEC = 0.086 × V + 2.66
Combination B	MDEC = 0.111 × V + 2.04

ENERGY STAR® updated its maximum daily energy consumption efficiency levels, also in kilowatt-hours per day, for refrigerated vending machines that went into effect on April 29, 2020. These efficiency levels are based on refrigerated volume.

Equipment Class	Maximum daily energy consumption (kilowatt-hours per day)
Class A – a refrigerated bottled or canned beverage vending machine that is not a combination vending machine and in which 25% or more of the surface area on the front side of the beverage vending machine is transparent	MDEC = 0.04836 x V + 2.2599
Class B – any refrigerated bottled or canned beverage vending machine that is not considered to be Class A and is not a combination vending machine	MDEC = 0.04576 x V+1.936
Combination A – a combination vending machine where 25% or more of the surface area on the front side of the beverage vending machine is transparent	MDEC = 0.07998 x V + 2.4738
Combination B – a combination vending machine that is not considered to be Combination A	MDEC = 0.09768 x V + 1.7952

Commercial Ventilation

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Performance and Cost Characteristics » Commercial Constant Air Volume

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average[3]	Low[4,5]	Typical[4,6]	High[4,7]	ENERGY STAR	Typical[4,6]	High[4,7]	Typical[4,6]	High[4,7]	Typical[4,6]	High[4,7]
System Airflow (CFM)	15,000	16,300	16,300	16,300	16,300	N/A	16,300	16,300	16,300	16,300	16,300	16,300
System Fan Power (kW)	11.56	11.56	11.56	10.98	10.78	N/A	10.98	10.78	10.98	10.78	10.98	10.78
Specific Fan Power (W/CFM)	0.771	0.709	0.709	0.674	0.661	N/A	0.674	0.661	0.674	0.661	0.674	0.661
Annual Fan Energy Use (kWh/y)[1]	43,924	23,038	23,038	21,886	20,792	N/A	21,886	20,792	21,886	20,792	21,886	20,792
Average Life (years)	35	35	35	35	35	N/A	35	35	35	35	35	35
Total Installed Cost (2022$)[2]	$80,288	$83,083	$83,083	$86,901	$90,651	N/A	$86,901	$90,651	$86,901	$90,651	$86,901	$90,651
Annual Maintenance Cost (2022$)	$1,054	$1,054	$1,054	$1,054	$1,054	N/A	$1,054	$1,054	$1,054	$1,054	$1,054	$1,054
Total Installed Cost (2022$/thousand cubic feet per minute [CFM])	$5,353	$5,097	$5,097	$5,331	$5,561	N/A	$5,331	$5,561	$5,331	$5,561	$5,331	$5,561
Annual Maintenance Cost (2022$/thousand CFM)	$70	$65	$65	$65	$65	N/A	$65	$65	$65	$65	$65	$65

1. Based on 3800 operating hours per year (ADL, 1999) and typical zone air flow requirement profile (ASHRAE S45.11-2012)
2. Total installed cost of 16,300 CFM constant air volume (CAV) air handling unit (AHU) and hypothetical supply ductwork layout
3. Based on ASHRAE 90.1-2016 and 2019 fan power limit (Table 6.5.3.1.1-1) with no pressure drop adjustment. Assumed 80% motor load and 91% motor efficiency
4. ASHRAE 90.1-2016 and 2019 Section 6.5.3.2 require minimum two-speed fan control (no longer always constant volume).
5. Two-speed variable frequency drive (VFD)
6. Modulating VFD
7. Modulating custom engineered VFD

Performance and Cost Characteristics » Commercial Constant Air Volume

Final

- Constant air volume (CAV) ventilation systems are common, inexpensive, air-side HVAC systems that operate in response to a single control zone. Historically, these systems provide a constant flow rate of air (typically a mix of recirculated and outside air) and adjust the supply temperature of that air in order to maintain the space temperature setpoint. Beginning with ASHRAE 90.1-2013 and continued in ASHRAE 90.1-2019, new CAV ventilation systems were mandated to have at least two fan speed settings with the requirement of a maximum 40% power at 66% flow. Systems with variable speed fans are increasingly popular, making the term "constant air volume" somewhat of a misnomer for this system type. This analysis examines only the fan energy of the CAV system.
- There is movement in the industry and in energy codes to reduce fan power. ASHRAE 90.1 includes fan power limits for CAV systems. Fan power can be minimized through good design practice (efficient duct layout, low pressure drop ductwork, filters, coils), proper fan selection, and high efficiency type fans. ASHRAE 90.1-2019 now requires a minimum fan efficiency grade (FEG, based on AMCA 205-12: Energy Efficiency Classification for Fans) of 67 and a design operating fan efficiency within 15% of the maximum fan total efficiency. There are exceptions to this requirement, including packaged systems such as the CAV system type considered here. Still the fan power limits are expected to become more stringent, and fan efficiency will become more important throughout the industry.
- The unit characterized in this report is a 16,300 CFM CAV system. The average commercial building is approximately 16,300 square feet (CBECS 2018). Assuming 1 CFM is needed per square foot of floor area results in a 16,300 CFM air handling unit.
- A 16,300 CFM CAV packaged indoor air handling unit with cooling and heating coils can be installed for approximately $71,829 (RS Means 2022). Ductwork would cost approximately $9,272 additional ($81,101 total). A two-speed motor (estimated $500 incremental cost) and variable frequency drive (estimated $5,800) add cost. Custom engineered variable frequency drives (estimated $9,550) and premium efficiency motors (estimated additional $1,500) add an additional cost to the system.
- Annual maintenance cost assumes 8 hours worth of labor by a technician to perform the necessary tasks (e.g., filter replacement, draining condenser water, etc.)
- ASHRAE Standard 90.1, which is used as a basis for most state energy codes, limits the fan power (brake HP or nameplate HP) for CAV systems. The 2016 version of Standard 90.1 was used to represent the 2018 minimum efficiency level (state energy codes typically refer to older versions of Standard 90.1 due to code revision cycles).
- Fan energy is affected by several factors, including fan type (e.g., centrifugal, axial), fan blade shape (e.g., forward-curved, backward-curved, backward-inclined, airfoil), drive type (belt or direct), configuration (plenum or housed centrifugal), system effects, duct design, filter and coil pressure drops, motor efficiency, and speed and flow control.

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Performance and Cost Characteristics » Commercial Variable Air Volume

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average[3]	Low[4]	Typical[5]	High[6]	ENERGY STAR	Typical[6]	High[6,7]	Typical[6,7]	High[6,7]	Typical[6,7]	High[6,7]
System Airflow (CFM)	15,000	16,300	16,300	16,300	16,300	N/A	16,300	16,300	16,300	16,300	16,300	16,300
System Fan Power (kW)	15.99	15.99	15.99	15.99	15.99	N/A	15.99	15.19	15.99	15.19	15.99	15.19
Specific Fan Power (W/CFM)	1.066	1.066	0.981	0.981	0.981	N/A	0.981	0.932	0.981	0.932	0.981	0.932
Annual Fan Energy Use (kWh/y)[1]	24,699	24,082	24,082	22,878	21,734	N/A	22,878	21,734	22,878	21,734	22,878	21,734
Average Life (years)	28	28	28	28	28	N/A	28	28	28	28	28	28
Total Installed Cost (2022$)[2]	$103,327	$110,414	$118,814	$124,495	$124,995	N/A	$124,495	$124,995	$124,495	$124,995	$124,495	$124,995
Annual Maintenance Cost (2022$)	$1,054	$1,054	$1,054	$1,054	$1,054	N/A	$1,054	$1,054	$1,054	$1,054	$1,054	$1,054
Total Installed Cost (2022$/thousand CFM)	$6,888	$6,774	$7,289	$7,638	$7,668	N/A	$7,638	$7,668	$7,638	$7,668	$7,638	$7,668
Annual Maintenance Cost (2022$/thousand CFM)	$70	$65	$65	$65	$65	N/A	$65	$65	$65	$65	$65	$65

1. Based on 3800 operating hours per year (ADL, 1999) and typical zone air flow requirement profile (ASHRAE S45.11-2012)
2. Total installed cost of 16,300 CFM VAV AHU, VFD, (10) VAV boxes, (10) VAV controllers with associated space temperature sensor, and hypothetical supply ductwork layout
3. Based on ASHRAE 90.1-2016 and 2019 fan power limit (Table 6.5.3.1.1-1) with no pressure drop adjustment. Assumed 80% motor load and 91% motor efficiency
4. ASHRAE 90.1-2016 and 2019 Section 6.5.3.2 minimum power-flow requirement
5. ASHRAE 90.1-2019 fan power limit and typical VAV power-flow relationship for 40%-100% flow
6. ASHRAE 90.1-2019 fan power limit and typical VAV power-flow relationship for 30%-100% flow
7. High aerodynamic efficiency fan

Performance and Cost Characteristics » Commercial Variable Air Volume

Final

- Variable air volume (VAV) ventilation systems are the most common multi-zone system type specified today for conditioning commercial buildings. These systems provide conditioned air to multiple zone terminal units (VAV boxes) that use dampers to modulate the amount of cool air to each zone. An individual zone thermostat controls the VAV box damper to allow more or less cooling. If a zone requires heating, then the VAV box provides the minimum flow rate and typically includes a reheat coil to meet the space temperature setpoint. As VAV box dampers close in the system, a variable frequency drive reduces fan speed and flow continuously to meet current requirements.
- This analysis examines only the fan energy of the VAV system. VAV systems vary fan speed and flow to meet space conditioning requirements; minimum flow settings apply for DX cooling stages and gas furnace heating stages. Most hours of operation are much lower than full speed, and fan power varies with the cube of fan speed according to fan affinity laws. The 2012 ASHRAE Handbook: HVAC Systems and Equipment (p. 45.11) provided the typical flow profile used for this analysis. The unit characterized in this report is a 16,300 CFM VAV system.
- There is movement in the industry and in energy codes to reduce fan power. ASHRAE 90.1 includes fan power limits for VAV systems. Fan power can be minimized through good design practice (efficient duct layout, low pressure drop ductwork, filters, coils), proper fan selection, and high efficiency type fans. ASHRAE 90.1-2019 now requires a minimum fan efficiency grade (FEG, based on AMCA 205-12: Energy Efficiency Classification for Fans) of 67 and a design operating fan efficiency within 15% of the maximum fan total efficiency. There are exceptions to this requirement, including packaged systems such as the VAV system type considered here. Still the fan power limits are expected to become more stringent, and fan efficiency will become more important throughout the industry.
- A 16,300 CFM VAV packaged indoor air handling unit with cooling and heating coils can be installed for approximately $82,023 (RS Means 2022). Ductwork and (10) VAV boxes with reheat would cost approximately an additional $28,272. (10) VAV controllers and the associated space temperature sensor would cost approximately $8,400 ($118,695 total). A 15 hp variable frequency drive (estimated $5,800) is an additional cost.
- ASHRAE Standard 90.1, which is used as a basis for most state energy codes, limits the fan power for VAV systems (brake HP or nameplate HP). The 2016 version of Standard 90.1 was used to represent the 2018 minimum efficiency level (state energy codes typically refer to older versions of Standard 90.1 due to code revision cycles).
- Annual maintenance cost assumes 8 hours worth of labor by a technician to perform the necessary tasks (e.g., filter replacement, draining condenser water, etc.)
- Fan energy is affected by several factors, including fan type (e.g., centrifugal, axial), fan blade shape (e.g., forward-curved, backward-curved, backward-inclined, airfoil), drive type (belt or direct), configuration (plenum or housed centrifugal), system effects, duct design, filter and coil pressure drops, and motor VFD efficiency.

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Performance and Cost Characteristics » Commercial Fan Coil Units

Final

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average[5]	Low[3]	Typical[5]	High[6]	ENERGY STAR	Typical[4,6]	High[4,7]	Typical[4,7]	High[4,8]	Typical[4,8]	High[4,8,9]
System Airflow (CFM)	800	800	800	800	800	N/A	800	800	800	800	800	800
System Fan Power (kW)	0.241	0.241	0.241	0.148	0.148	N/A	0.141	0.134	0.134	0.136	0.136	0.129
Specific Fan Power (W/CFM)	0.302	0.302	0.301	0.185	0.185	N/A	0.176	0.167	0.167	0.170	0.170	0.162
Annual Fan Energy Use (kWh/y)[1]	543	542	542	333	333	N/A	316	301	301	306	306	291
Average Life (years)	37	37	37	37	37	N/A	37	37	37	37	37	37
Total Installed Cost (2022$)[2]	$2,845	$2,688	$3,038	$3,521	$3,961	N/A	$3,961	$4,161	$3,961	$4,161	$3,961	$4,161
Annual Maintenance Cost (2022$)	$117	$117	$117	$117	$117	N/A	$117	$117	$117	$117	$117	$117
Total Installed Cost (2022$/thousand CFM)	$3,557	$3,360	$3,798	$4,401	$4,951	N/A	$4,951	$5,201	$4,951	$5,201	$4,951	$5,201
Annual Maintenance Cost (2022$/thousand CFM)	$146	$146	$146	$146	$146	N/A	$146	$146	$146	$146	$146	$146

1. Based on 2250 operating hours per year (ADL, 1999) and typical zone air flow requirement profile (ASHRAE S45.11-2012)
2. Total installed cost of 2-ton horizontal two-pipe fan coil unit, housing, and controls
3. Based on ASHRAE 90.1-2016 and 2019 fan power limit (Table 6.5.3.1.1-1) with no pressure drop adjustment. Assumed 80% motor load and 91% motor efficiency
4. Based on ASHRAE 90.1-2016 and 2019 Section 6.5.3.6 requirement of electronically commutated or 70+% efficient fan motor
5. Permanent split capacitor fan motor
6. Electronically commutated fan motor (single speed)
7. Electronically commutated fan motor (two-speed)
8. Electronically commutated fan motor (variable speed)
9. High aerodynamic efficiency fan

Performance and Cost Characteristics » Commercial Fan Coil Units

Final

- Commercial fan coil units (FCUs) are self-contained, mass-produced assemblies that provide cooling, heating, or cooling and heating, but they do not include the source of cooling or heating. The unit characterized in this report is a cooling only (two-pipe), horizontal unit with housing and controls. Fan coil units are typically installed in or adjacent to the space being served and have no (or very limited) ductwork.
- According to manufacturer literature, the cooling capacity for a nominal 800 CFM fan coil unit is about 2 tons. This analysis examines only the fan energy of FCUs.
- Fan coil unit fan motors can be shaded pole, a single-phase AC motor with offset start winding and no capacitor; PSC, a single-phase AC motor with offset start winding with capacitor; or ECM, an AC electronically commutated permanent magnet DC motor. PSC motors are currently the most common motor type in FCUs, but manufacturers also offer single speed, two speed, and ECM motors as an option. ASHRAE 90.1-2019 requires an electronically commutated fan motor (or minimum motor efficiency of 70%) for this system.
- There is movement in the industry and in energy codes to reduce fan power. ASHRAE 90.1 includes fan power limits for FCUs. Fan power can be minimized through good design practice and high efficiency type fans. ASHRAE 90.1-2019 now requires a minimum fan efficiency grade (FEG, based on AMCA 205-12: Energy Efficiency Classification for Fans) of 67 and a design operating fan efficiency within 15% of the maximum fan total efficiency. There are exceptions to this requirement, including small systems such as the FCU considered here. Still the fan power limits are expected to become more stringent, and fan efficiency will become more important throughout the industry.
- Fan coil units have higher maintenance costs than central air systems due to the distributed nature of the system. For each unit, the filters must be changed, and drain systems must be flushed periodically.
- ASHRAE Standard 90.1, which is used as a basis for most state energy codes, limits the fan power (brake HP or nameplate HP). The 2016 version of Standard 90.1 was used to represent the 2018 minimum efficiency level (state energy codes typically refer to older versions of Standard 90.1 due to code revision cycles).
- Fan energy is affected by several factors, including fan type configuration, filter and coil pressure drops, motor efficiency, and fan speed control.

Appendix A
Data Sources

Guidehouse
1200 19th Street, NW, Suite 700
Washington, D.C. 20036

And

SAIC
8301 Greensboro Drive
McLean, VA 22102

Residential Lighting

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Data Sources » Residential General Service Incandescent Lamps (60 watt)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Assume Unchanged	N/A										
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2008												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case												
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Ref. Case												
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential General Service Incandescent Lamps (75 watt)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Assume Unchanged	N/A										
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2008												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case												
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Ref. Case												
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential General Service Halogen Lamps (60 watt Incandescent Equivalent)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Assume Unchanged	N/A	Distributor Websites or Product Catalogs	N/A								
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2008			DOE, 2008									
Average Lamp Life (thousand hours)	2016 EIA Ref. Case	Assume Unchanged		Distributor Websites									
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated		Distributor Websites									
Lamp Cost (2022$/klm)	Calculated			Calculated									
Labor Cost (2022$/h)	N/A			N/A									
Labor Installation (hours)													
Total Installed Cost (2022$)	Calculated			Calculated									
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources» Residential General Service Halogen Lamps (75 watt Incandescent Equivalent)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Calculated	N/A	Distributor Websites or Product Catalogs	N/A								
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2008			DOE, 2008									
Average Lamp Life (thousand hours)	2016 EIA Ref. Case	Distributor Websites or Product Catalogs		Distributor Websites									
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated		Distributor Websites									
Lamp Cost (2022$/klm)	Calculated			Calculated									
Labor Cost (2022$/h)	N/A			N/A									
Labor Installation (hours)													
Total Installed Cost (2022$)	Calculated			Calculated									
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential General Service Compact Fluorescent Lamps (60 watt Incandescent Equivalent)

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Calculated	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	NCI, 2019					
Lamp Lumens													
Lamp Efficacy (lm/W)			Calculated										
CRI		Assume Unchanged	Distributor Websites or Product Catalogs				N/A						
Correlated Color Temperature (CCT)	Product Catalogs												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case												
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated	Distributor Websites or Product Catalogs			N/A	N/A	NCI, 2019					
Lamp Cost (2022$/klm)			Calculated										
Labor Cost (2022$/h)	N/A						N/A						
Labor Installation (hours)													
Total Installed Cost (2022$/klm)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential General Service LED Lamps (60 Watt Equivalent)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average		Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Installation (hours)													
Total Installed Cost (2022$/klm)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential General Service Filament-LED Lamps (60 Watt Equivalent)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average		Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Reflector Lamps (65W BR30 Incandescent)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Assume Unchanged	N/A	Distributor Websites or Product Catalogs	N/A								
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2012(1)												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case												
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Ref. Case			Distributor Websites or Product Catalogs									
Lamp Cost (2022$/klm)				Calculated									
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Reflector Lamps (PAR30 Halogen)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Assume Unchanged	N/A	Distributor Websites or Product Catalogs	N/A								
Lamp Lumens		Calculated											
Lamp Efficacy (lm/W)		Assume Unchanged											
CRI													
Correlated Color Temperature (CCT)	DOE, 2012(1)												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case												
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated		Distributor Websites or Product Catalogs									
Lamp Cost (2022$/klm)				Calculated									
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Reflector Lamps (PAR30 Halogen Infrared Reflector (HIR)

Final

DATA SOURCES	2009	2020	2015				2023	2020		2030		2040	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Calculated	N/A	Distributor Websites or Product Catalogs	N/A								
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI		Assume Unchanged											
Correlated Color Temperature (CCT)	DOE, 2012(1)												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case												
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated		Distributor Websites or Product Catalogs									
Lamp Cost (2022$/klm)				Calculated									
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Reflector Lamps (BR30 CFL)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case / Calculated		N/A										
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2012(1)												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case / Calculated												
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Ref. Case / Calculated												
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Reflector LED BR30

Final

DATA SOURCES	2015	2020	2022			2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Reflector LED PAR38

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Linear Fluorescent Lamp T12

Final

DATA SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Assume Unchanged	N/A								
Lamp Lumens											
Lamp Efficacy (lm/W)	Calculated										
System Wattage											
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)	2016 EIA Ref. Case	Chapter 5; Table 5.8.16 of GSFL Ballast Final Rule TSD (DOE, 2020)									
CRI	2016 EIA Ref. Case	Assume Unchanged									
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)	DOE, 2017										
Lamp Price (2022$)	2016 EIA Ref. Case										
Ballast Price (2022$)											
Fixture Price (2022$)											
Lamp Cost (2022$/klm)	Calculated										
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)	2016 EIA Ref. Case										
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)	Calculated										
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Residential Linear Fluorescent Lamp T8

Final

DATA SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	Calculated	Distributor Websites				Calculated					
Lamp Lumens	2016 EIA Ref. Case										
Lamp Efficacy (lm/W)	2015 GSFL TSD, Figure 11.5.4	Calculated									
System Wattage	Calculated										
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)	2016 EIA Ref. Case	Chapter 5; Table 5.8.15 of GSFL Ballast Final Rule TSD (DOE, 2020)									
CRI	2016 EIA Ref. Case	Distributor Websites				Distributor Websites					
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)						Calculated					
Annual Operating Hours (h/y)	DOE, 2017										
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated	Distributor Websites			Calculated					
Ballast Price (2022$)		N/A									
Fixture Price (2022$)		Calculated									
Lamp Cost (2022$/klm)	Calculated										
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)	2016 EIA Ref. Case	Assume unchanged	2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)			N/A								
Total Installed Cost (2022$)	Calculated										
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Residential Linear Fluorescent Lamp T5

Final

DATA SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	Calculated	Distributor Websites				Assume unchanged					
Lamp Lumens	2016 EIA Ref. Case										
Lamp Efficacy (lm/W)	2015 GSFL TSD, Figure 11.5.4	Calculated									
System Wattage	Calculated										
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)	Chapter 5; Table 5.3.32 of GSFL IRL Final Rule TSD (DOE, 2015)	Chapter 5; Table 5.8.6 of GSFL Ballast Final Rule TSD (DOE, 2020)									
CRI	2016 EIA Ref. Case	Distributor Websites									
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)	DOE, 2017										
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated	Distributor Websites			Calculated					
Ballast Price (2022$)		N/A									
Fixture Price (2022$)		Calculated									
Lamp Cost (2022$/klm)	Calculated										
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)	2016 EIA Ref. Case		2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)			N/A								
Total Installed Cost (2022$)	Calculated										
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources» Residential Linear LED Replacement Lamp 2-Lamp System

Final

DATA SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	LED Webscrape Database	DOE Web Scrape Database	Distributor websites			Calculated					
Lamp Lumens						Assume same as 2022 Typical and High					
Lamp Efficacy (lm/W)						Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage	Calculated										
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)	N/A										
CRI	2016 EIA Ref. Case	2016 EIA Ref. Case	Distributor Websites			Distributor Websites					
Correlated Color Temperature (CCT)	2016 EIA Ref. Case	Distributor Websites									
Average Lamp Life (thousand hours)	LED Webscrape Database	DOE Web Scrape Database									
Annual Operating Hours (h/y)	DOE, 2017										
Lamp Price (2022$)	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A				N/A					
Fixture Price (2022$)		N/A									
Lamp Cost (2022$/klm)	Calculated										
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)	N/A										
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)	Calculated										
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Residential Linear LED Luminaire

Final

DATA SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A										
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Calculated					
System Lumens						Assume same as 2022 Typical and High					
System Efficacy (lm/W)						Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Efficiency (BLE)	N/A										
CRI	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Distributor Websites					
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)	DOE, 2017										
Lamp or Luminaire Price (2022$)	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)	N/A										
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)	2016 EIA Ref. Case		2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)			N/A								
Total Installed Cost (2022$)	Calculated										
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Residential Outdoor Lamps (Security: BR30 Incandescent)

Final

DATA SOURCES	2009	2020	2015				2023	2020		2030		2040	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Same as indoor Residential Incandescent Reflector												
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)													
Lamp Price (2022$)													
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)													
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Security: PAR38 Halogen)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Interpolation Based on Commercial PAR38		Same as Commercial PAR38 Halogen										
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)													
Lamp Price (2022$)													
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)													
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Security: PAR38 HIR)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Interpolated from Commercial PAR38 HIR		Same as Commercial PAR38 HIR										
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)													
Lamp Price (2022$)													
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)													
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Security: CFL PAR38)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case / Calculated		N/A										
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2012(1)												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case / Calculated												
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Ref. Case / Calculated												
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Security: LED PAR38)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Same as Residential LED PAR38												
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)													
Lamp Price (2022$)													
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)													
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Porch: A19 Incandescent)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Same as Residential General Service 75W Incandescent												
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)													
Lamp Price (2022$)													
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)													
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Porch: Halogen A-Type)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Same as Residential General Service 75W Equivalent Halogen												
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)													
Lamp Price (2022$)													
Lamp Cost (2022$/klm)													
Labor Cost (2022$/h)													
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Porch: CFL Bare Spiral)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Calculated	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	NCI, 2019					
Lamp Lumens													
Lamp Efficacy (lm/W)			Calculated										
CRI		Assume Unchanged	Distributor Websites or Product Catalogs				N/A						
Correlated Color Temperature (CCT)	Product Catalogs												
Average Lamp Life (thousand hours)	2016 EIA Ref. Case												
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Ref. Case	Calculated	Distributor Websites or Product Catalogs			N/A	N/A	NCI, 2019					
Lamp Cost (2022$/klm)			Calculated										
Labor Cost (2022$/h)	N/A						N/A						
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Outdoor Lamps (Porch: LED A-Type)

Final

DATA SOURCES	2015	2020	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

Commercial Lighting

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Data Sources » Commercial General Service 100W Incandescent Lamp in Recessed Can Fixture

Final

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case		N/A										
Lamp Lumens													
Lamp Efficacy (lm/W)													
System Wattage													
System Lumens													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2008												
Average Lamp Life (thousand hours)	2016 EIA Reference Case												
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Reference Case; Calculated												
Ballast Price (2022$)													
Fixture Price (2022$)													
Lamp Cost (2022$/klm)													
System (l/b/f) Cost (2022$/klm)													
Labor Cost (2022$/h)	2016 EIA Reference Case												
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)	Calculated												
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial General Service Halogen Lamp (100W Incandescent Equivalent) in Recessed Can Fixture

Final

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	Assume Unchanged	N/A	Product Catalogs	N/A								
Lamp Lumens													
Lamp Efficacy (lm/W)													
System Wattage													
System Lumens													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI													
Correlated Color Temperature (CCT)	DOE, 2008												
Average Lamp Life (thousand hours)	2016 EIA Reference Case	Assume Unchanged											
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Reference Case	DOE, 2019		Distributor Websites									
Ballast Price (2022$)													
Fixture Price (2022$)													
Lamp Cost (2022$/klm)				Calculated									
System (l/b/f) Cost (2022$/klm)													
Labor Cost (2022$/h)	2016 EIA Reference Case			2022 RS Means Online									
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)	Calculated			Calculated									
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial General Service 100W Equivalent CFL Bare Spiral in Recessed Can Fixture

Final

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	Calculated / Guidehouse	Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)								NCI, 2019					
System Wattage							Same as lamp wattage						
System Lumens							Calculated						
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI							N/A	Assume Unchanged					
Correlated Color Temperature (CCT)	2016 EIA Reference Case												
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)	DOE, 2017					N/A	DOE, 2017						
Lamp Price (2022$)	2016 EIA Reference Case; Calculated		Distributor Websites				N/A	NCI, 2019					
Ballast Price (2022$)													
Fixture Price (2022$)			NCI, 2019										
Disposal Cost (2022$)	EPA, 2022							EPA, 2022					
Lamp Cost (2022$/klm)	Calculated							NCI, 2019					
System (l/b/f) Cost (2022$/klm)													
Labor Cost (2022$/h)	2016 EIA Reference Case		2022 RS Means Online					2022 RS Means Online					
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)	Calculated							Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial General Service 100W Equivalent LED Replacement Lamp in Recessed Can Fixture

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated											
System Lumens													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	N/A	Assume Unchanged					
Correlated Color Temperature (CCT)						N/A							
Average Lamp Life (thousand hours)						ENERGY STAR, 2020		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)				Assume Unchanged	
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A						N/A					
Fixture Price (2022$)													
Lamp Cost (2022$/klm)		Calculated						Calculated					
System (l/b/f) Cost (2022$/klm)		N/A						N/A					
Labor Cost (2022$/h)		2016 EIA Reference Case	2022 RS Means Online					2022 RS Means Online					
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)		Calculated						Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial Halogen Reflector Lamp (PAR38) in Recessed Can Fixture

Final

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	2016 EIA Reference Case / Calculated, NCI, 2019	N/A	Distributor Websites or Product Catalogs	N/A								
Lamp Lumens													
Lamp Efficacy (lm/W)													
System Wattage													
System Lumens													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Reference Case; Calculated			Distributor Websites or Product Catalogs									
Ballast Price (2022$)													
Fixture Price (2022$)													
Lamp Cost (2022$/klm)				Calculated									
System (l/b/f) Cost (2022$/klm)													
Labor Cost (2022$/h)	2016 EIA Reference Case			2022 RS Means Online									
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)	Calculated			Calculated									
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial Halogen Infrared Reflector Lamp (PAR38) in Recessed Can Fixture

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case		N/A	Distributor Websites or Product Catalogs	N/A								
Lamp Lumens													
Lamp Efficacy (lm/W)													
System Wattage													
System Lumens													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)													
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017									
Lamp Price (2022$)	2016 EIA Reference Case; Calculated			Distributor Websites or Product Catalogs									
Ballast Price (2022$)													
Fixture Price (2022$)													
Lamp Cost (2022$/klm)				Calculated									
System (l/b/f) Cost (2022$/klm)													
Labor Cost (2022$/h)	2016 EIA Reference Case			2022 RS Means Online									
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)	Calculated			Calculated									
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial LED Reflector Lighting (PAR38)

Final

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated											
System Lumens													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	N/A	Assume Unchanged					
Correlated Color Temperature (CCT)						N/A							
Average Lamp Life (thousand hours)						ENERGY STAR, 2020		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)				Assume Unchanged	
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A						N/A					
Fixture Price (2022$)													
Lamp Cost (2022$/klm)		Calculated						Calculated					
System (l/b/f) Cost (2022$/klm)		N/A						N/A					
Labor Cost (2022$/h)		2016 EIA Reference Case	2022 RS Means Online					2022 RS Means Online					
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)		Calculated						Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial 4-ft T8 F32 Commodity in 2-Lamp System

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Calculated	Assume same as residential T8								
Lamp Lumens		Assume same as residential T8									
Lamp Efficacy (lm/W)		SSL Forecast for 2018									
System Wattage		Calculated									
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		Assume unchanged	Chapter 5; Table 5.8.1 of GSFL Ballast Final Rule TSD (DOE, 2020)								
CRI		Assume same as residential T8									
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		SSL Forecast for 2018	Assume same as residential T8			Calculated					
Ballast Price (2022$)											
Fixture Price (2022$)											
Disposal Costs (2022$)	EPA, 2022										
Lamp Cost (2022$/klm)	2016 EIA Ref. Case	Calculated									
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)		2016 EIA Ref. Case	2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources» Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Ref. Case	Distributor Websites				
Lamp Lumens						
Lamp Efficacy (lm/W)						
System Wattage	Calculated					
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency (BLE)	Chapter 5; Table 5.8.1 of GSFL Ballast Final Rule TSD (DOE, 2020)					
CRI	2016 EIA Ref. Case	Distributor Websites				
Correlated Color Temperature (CCT)						
Average Lamp Life (thousand hours)						
Annual Operating Hours (h/y)		DOE, 2017				
Lamp Price (2022$)		Calculated	Distributor Websites	Calculated		
Ballast Price (2022$)						
Fixture Price (2022$)						
Disposal Costs (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	Calculated					
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)	2016 EIA Ref. Case		2022 RS Means Online			
Labor System Installation (hours)						
Labor Lamp Change (hours)						
Total Installed Cost (2022$)	Calculated					
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial 4-ft T5 F28 in 2-Lamp System

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Calculated	Assume same as residential T5								
Lamp Lumens		Assume same as residential T5, 2022									
Lamp Efficacy (lm/W)		SSL Forecast for 2018									
System Wattage	Calculated										
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)	Chapter 5; Table 5.8.6 of GSFL Ballast Final Rule TSD (DOE, 2020)										
CRI	2016 EIA Ref. Case	Assume same as residential T5									
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		SSL Forecast for 2018	Assume same as residential T5			Calculated					
Ballast Price (2022$)											
Fixture Price (2022$)											
Disposal Costs (2022$)	EPA, 2022										
Lamp Cost (2022$/klm)	2016 EIA Ref. Case	Calculated									
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)		2016 EIA Ref. Case	2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 4-ft Linear LED Replacement Lamp in 2-Lamp System

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	LED Webscrape Database	Distributor websites			Calculated					
Lamp Lumens						Assume same as 2022 Typical and High					
Lamp Efficacy (lm/W)						Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated				Calculated					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		N/A				N/A					
CRI		Distributor websites									
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		LED Webscrape Database	Distributor Websites			Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A				N/A					
Fixture Price (2022$)											
Lamp Cost (2022$/klm)		Calculated									
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)		Assume unchanged	2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 4-ft Linear LED Luminaire to Replace 2-Lamp Systems

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	N/A				N/A					
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage		LED Webscrape Database	Distributor websites			Calculated					
System Lumens						Assume same as 2022 Typical and High					
System Efficacy (lm/W)						Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Efficiency (BLE)		N/A				N/A					
CRI		Distributor websites									
Correlated Color Temperature (CCT)											
Average Lifetime (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp or Luminaire Price (2022$)		LED Webscrape Database	Distributor Websites			Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A									
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)		Calculated									
Labor Cost (2022$/h)		Assume unchanged	2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System with Occupancy Sensor

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Ref. Case	Distributor Websites				
Lamp Lumens						
Lamp Efficacy (lm/W)						
System Wattage		Calculated				
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency (BLE)		Chapter 5; Table 5.8.1 of GSFL Ballast Final Rule TSD (DOE, 2020)				
CRI		Distributor Websites				
Correlated Color Temperature (CCT)						
Average Lamp Life (thousand hours)						
Annual Operating Hours (h/y)		DOE, 2017				
Lamp Price (2022$)		Calculated	Distributor Websites	Calculated		
Ballast Price (2022$)		N/A				
Fixture Price (2022$)		Calculated	Distributor Websites	Calculated		
Occupancy Sensor Price (2022$)	N/A			Distributor Websites		
Disposal Costs (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Ref. Case	Calculated				
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)		Assume unchanged	2022 RS Means Online			
Labor System Installation (hours)						
Labor Lamp Change (hours)						
Total Installed Cost (2022$)		Calculated				
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System with Specular Reflector

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Ref. Case	Distributor Websites				
Lamp Lumens						
Lamp Efficacy (lm/W)						
System Wattage		Calculated				
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency (BLE)		Chapter 5; Table 5.8.1 of GSFL Ballast Final Rule TSD (DOE, 2020)				
CRI		Distributor Websites				
Correlated Color Temperature (CCT)						
Average Lamp Life (thousand hours)						
Annual Operating Hours (h/y)		DOE, 2017				
Lamp Price (2022$)		Calculated	Distributor Websites	Calculated		
Ballast Price (2022$)		N/A				
Fixture Price (2022$)		Calculated	Distributor Websites	Calculated		
Reflector Price (2022$)	N/A			Distributor Websites		
Disposal Costs (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Ref. Case	Calculated				
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)		Assume unchanged	2022 RS Means Online			
Labor System Installation (hours)						
Labor Lamp Change (hours)						
Total Installed Cost (2022$)		Calculated				
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial 4-ft T8 F28 High-efficiency and High-output in 2-Lamp System with Occupancy Sensor and Specular Reflector

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Ref. Case	Calculated	Distributor Websites	Distributor Websites	Distributor Websites	Distributor Websites
Lamp Lumens		Distributor Websites				
Lamp Efficacy (lm/W)						
System Wattage		Calculated				
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency (BLE)		Chapter 5; Table 5.8.1 of GSFL Ballast Final Rule TSD (DOE, 2020)				
CRI		Distributor Websites				
Correlated Color Temperature (CCT)						
Average Lamp Life (thousand hours)						
Annual Operating Hours (h/y)		DOE, 2017				
Lamp Price (2022$)		Calculated	Distributor Websites	Calculated	Calculated	Calculated
Ballast Price (2022$)						
Fixture Price (2022$)						
Reflector Price (2022$)		N/A		Distributor Websites		
Occupancy Sensor Price (2022$)						
Disposal Costs (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Ref. Case	Calculated				
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)		Assume unchanged	2022 RS Means Online			
Labor System Installation (hours)						
Labor Lamp Change (hours)						
Total Installed Cost (2022$)		Calculated				
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial 8-ft T8 F59 Typical Efficiency in a 2-Lamp System

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Calculated	Distributor Websites			Assume same as 2022					
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage		Calculated	Calculated			Calculated					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		Assume unchanged	Chapter 5; Table 5.8.1 of GSFL Ballast Final Rule TSD (DOE, 2020)								
CRI	2016 EIA Ref. Case	Distributor Websites				Assume same as 2022					
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		Calculated	Distributor Websites			Calculated					
Ballast Price (2022$)											
Fixture Price (2022$)											
Disposal Costs (2022$)	EPA, 2022										
Lamp Cost (2022$/klm)	2016 EIA Ref. Case	Calculated									
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)		Assume unchanged	2022 RS Means Online								
Labor System Installation (hours)	Chapter 8; Table 8.2.4 of GSFL IRL Preliminary Analysis TSD (DOE, 2013)										
Labor Lamp Change (hours)	Chapter 8; Table 8.2.4 of GSFL IRL Preliminary Analysis TSD (DOE, 2013)										
Total Installed Cost (2022$)	2016 EIA Ref. Case	Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 8-ft T8 F96 High-Output in a 2-Lamp System

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	Assume same as 2022 typical	Distributor Websites			Assume same as 2022					
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage		Calculated									
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		Chapter 5; Table 5.3.26 GSFL IRL Final Rule TSD (DOE, 2014)									
CRI		Distributor Websites									
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		Calculated	Distributor Websites			Calculated					
Ballast Price (2022$)											
Fixture Price (2022$)											
Disposal Costs (2022$)	EPA, 2022										
Lamp Cost (2022$/klm)	2016 EIA Ref. Case	Calculated	Calculated								
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)		2016 EIA Ref. Case	2022 RS Means Online								
Labor System Installation (hours)	Chapter 8; Table 8.2.4 of GSFL IRL Preliminary Analysis TSD (DOE, 2013)										
Labor Lamp Change (hours)	Chapter 8; Table 8.2.4 of GSFL IRL Preliminary Analysis TSD (DOE, 2013)										
Total Installed Cost (2022$)	2016 EIA Ref. Case	Calculated				Calculated					
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 8-ft Linear LED Replacement Lamp for a 2 Lamp System

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	2016 EIA Ref. Case, 2015 typical	Distributor Websites			Calculated					
Lamp Lumens						Assume same as 2022 Typical and High					
Lamp Efficacy (lm/W)			Calculated			Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated				Calculated					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		N/A									
CRI		2016 EIA Ref. Case, 2015 typical	Distributor Websites			Assume same as 2022					
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		2016 EIA Ref. Case, 2015 typical	Distributor Websites			Calculated					
Ballast Price (2022$)			N/A								
Fixture Price (2022$)											
Lamp Cost (2022$/klm)			Calculated								
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)		2016 EIA Ref. Case	2022 RS Means Online								
Labor System Installation (hours)		N/A									
Labor Lamp Change (hours)		Chapter 8; Table 8.2.4 of GSFL IRL Preliminary Analysis TSD (DOE, 2013)									
Total Installed Cost (2022$)		Calculated				Calculated					
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 8-ft Linear LED Luminaire Replacement for a 2-Lamp System

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	N/A									
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage		2016 EIA Ref. Case, 2015 typical	Distributor Websites			Calculated					
System Lumens						Assume same as 2022 Typical and High					
System Efficacy (lm/W)						Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Efficiency (BLE)		N/A									
CRI		2016 EIA Ref. Case, 2015 typical	Distributor Websites								
Correlated Color Temperature (CCT)											
Average Lifetime (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp or Luminaire Price (2022$)		2016 EIA Ref. Case, 2015 typical	Distributor Websites								
Ballast Price (2022$)			N/A								
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)			Calculated								
Labor Cost (2022$/h)		2016 EIA Ref. Case	2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)		N/A									
Total Installed Cost (2022$)		2016 EIA Ref. Case	Calculated								
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial Mercury Vapor Low-bay

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Reference Case	Assume Unchanged	Distributor Websites or Product Catalogs	N/A	N/A	N/A
Lamp Lumens						
Lamp Efficacy (lm/W)						
System Wattage						
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency			Chapter 5; Table 5.7.24 of HID Final Determination TSD (DOE, 2015)			
CRI			Distributor Websites or Product Catalogs			
Correlated Color Temperature (CCT)						
Average Lamp Life (thousand hours)			Chapter 3; Section 3.4.2 of HID Final Determination TSD (DOE, 2015)			
Annual Operating Hours (h/y)	DOE, 2017					
Lamp Price (2022$)	2016 EIA Reference Case; Calculated		Distributor Websites or Product Catalogs			
Ballast Price (2022$)						
Fixture Price (2022$)			Chapter 7 & Appendix 6A; Table 6A.3.4 of HID Final Determination TSD (DOE, 2015), Calculated			
Disposal Cost (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	Calculated					
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)	2016 EIA Reference Case		Chapter 9; Section 9.2.2.1 of HID Final Determination TSD (DOE, 2015)			
Labor System Installation (hours)			2022 RS Means Online			
Labor Lamp Change (hours)						
Total Installed Cost (2022$)	Calculated		Calculated			
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial Metal Halide Low-bay

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	Assume Unchanged		Distributor Websites or Product Catalogs	Calculated		
Lamp Lumens	Distributor Websites or Product Catalogs; Calculated			Assume Unchanged		
Lamp Efficacy (lm/W)				Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
System Wattage	2016 EIA Reference Case	Assume Unchanged				
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency			Chapter 5; Table 5.7.24 of HID Final Determination TSD (DOE, 2015)	Assume Unchanged		
CRI			Distributor Websites or Product Catalogs			
Correlated Color Temperature (CCT)						
Average Lamp Life (thousand hours)			Chapter 3; Section 3.4.2 of HID Final Determination TSD (DOE, 2015)	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
Annual Operating Hours (h/y)	DOE, 2017		DOE, 2017			
Lamp Price (2022$)	Distributor Websites or Product Catalogs ; Calculated		Distributor Websites or Product Catalogs			
Ballast Price (2022$)	2016 EIA Reference Case; Calculated					
Fixture Price (2022$)			Chapter 7 & Appendix 6A; Table 6A.3.4 of HID Final Determination TSD (DOE, 2015), Calculated			
Disposal Cost (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Reference Case; Calculated		Calculated			
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)	2016 EIA Reference Case		Chapter 9; Section 9.2.2.1 of HID Final Determination TSD (DOE, 2015)			
Labor System Installation (hours)			2022 RS Means Online			
Labor Lamp Change (hours)						
Total Installed Cost (2022$)	Calculated					
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial Sodium Vapor Low-bay

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Reference Case	Assume Unchanged	Distributor Websites or Product Catalogs	Calculated		
Lamp Lumens				Assume Unchanged		
Lamp Efficacy (lm/W)				Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
System Wattage						
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency			Chapter 5; Table 5.7.24 of HID Final Determination TSD (DOE, 2015)	Assume Unchanged		
CRI						
Correlated Color Temperature (CCT)			Distributor Websites or Product Catalogs			
Average Lamp Life (thousand hours)			Chapter 3; Section 3.4.2 of HID Final Determination TSD (DOE, 2015)	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
Annual Operating Hours (h/y)	DOE, 2017		DOE, 2017			
Lamp Price (2022$)	2016 EIA Reference Case; Calculated		Distributor Websites or Product Catalogs			
Ballast Price (2022$)						
Fixture Price (2022$)			Chapter 7 & Appendix 6A; Table 6A.3.4 of HID Final Determination TSD (DOE, 2015), Calculated			
Disposal Cost (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Reference Case; Calculated		Calculated	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)	2016 EIA Reference Case		Chapter 9; Section 9.2.2.1 of HID Final Determination TSD (DOE, 2015)			
Labor System Installation (hours)			2022 RS Means Online			
Labor Lamp Change (hours)						
Total Installed Cost (2022$)	Calculated					
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial LED Low-bay Luminaire

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A										
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	N/A	Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency		N/A		N/A		N/A					
CRI		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs		Assume Unchanged					
Correlated Color Temperature (CCT)											
Average Lifetime (thousand hours)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017							
Lamp or Luminaire Price (2022$)	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	N/A	Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A		N/A							
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)		Calculated		Calculated		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Labor Cost (2022$/h)		2016 EIA Reference Case		2022 RS Means Online							
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)	Calculated			Calculated							
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial Mercury Vapor High-Bay

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Reference Case	Assume Unchanged	Distributor Websites or Product Catalogs	N/A		
Lamp Lumens						
Lamp Efficacy (lm/W)						
System Wattage						
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency			Chapter 5; Table 5.7.24 of HID Final Determination TSD (DOE, 2015)			
CRI						
Correlated Color Temperature (CCT)			Distributor Websites or Product Catalogs			
Average Lamp Life (thousand hours)			Chapter 3; Section 3.4.2 of HID Final Determination TSD (DOE, 2015)			
Annual Operating Hours (h/y)	DOE, 2017		DOE, 2017			
Lamp Price (2022$)	2016 EIA Reference Case; Calculated		Distributor Websites or Product Catalogs			
Ballast Price (2022$)						
Fixture Price (2022$)			Chapter 7 & Appendix 6A; Table 6A.3.4 of HID Final Determination TSD (DOE, 2015), Calculated			
Disposal Cost (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Reference Case; Calculated		Calculated			
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)	2016 EIA Reference Case		Chapter 9; Section 9.2.2.1 of HID Final Determination TSD (DOE, 2015)			
Labor System Installation (hours)			2022 RS Means Online			
Labor Lamp Change (hours)						
Total Installed Cost (2022$)	Calculated		Calculated			
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial Metal Halide High-Bay

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Reference Case	Assume Unchanged	Distributor Websites or Product Catalogs	Calculated		
Lamp Lumens		2016 EIA Reference Case; Calculated		Assume Unchanged		
Lamp Efficacy (lm/W)				Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
System Wattage		Assume Unchanged				
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency			Chapter 5; Table 5.7.24 of HID Final Determination TSD (DOE, 2015)	Assume Unchanged		
CRI						
Correlated Color Temperature (CCT)			Distributor Websites or Product Catalogs			
Average Lamp Life (thousand hours)			Chapter 3; Section 3.4.2 of HID Final Determination TSD (DOE, 2015)	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
Annual Operating Hours (h/y)	DOE, 2017		DOE, 2017			
Lamp Price (2022$)	2016 EIA Reference Case; Calculated		Distributor Websites or Product Catalogs			
Ballast Price (2022$)						
Fixture Price (2022$)			Chapter 7 & Appendix 6A; Table 6A.3.4 of HID Final Determination TSD (DOE, 2015), Calculated			
Disposal Cost (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Reference Case; Calculated		Calculated	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)	2016 EIA Reference Case		Chapter 9; Section 9.2.2.1 of HID Final Determination TSD (DOE, 2015)			
Labor System Installation (hours)			2022 RS Means Online			
Labor Lamp Change (hours)						
Total Installed Cost (2022$)	Calculated					
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial Sodium Vapor High-Bay

Final

DATA SOURCES	2012	2018	2022	2030	2040	2050
	Installed Stock Average	Installed Stock Average	Typical	Typical	Typical	Typical
Lamp Wattage	2016 EIA Reference Case	Assume Unchanged	Distributor Websites or Product Catalogs	Calculated		
Lamp Lumens				Assume Unchanged		
Lamp Efficacy (lm/W)				Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
System Wattage						
System Lumens						
System Efficacy (lm/W)						
Ballast Efficiency			Chapter 5; Table 5.7.24 of HID Final Determination TSD (DOE, 2015)	Assume Unchanged		
CRI			Distributor Websites or Product Catalogs			
Correlated Color Temperature (CCT)						
Average Lamp Life (thousand hours)			Chapter 3; Section 3.4.2 of HID Final Determination TSD (DOE, 2015)	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
Annual Operating Hours (h/y)	DOE, 2017		DOE, 2017			
Lamp Price (2022$)	2016 EIA Reference Case; Calculated		Distributor Websites or Product Catalogs			
Ballast Price (2022$)						
Fixture Price (2022$)			Chapter 7 & Appendix 6A; Table 6A.3.4 of HID Final Determination TSD (DOE, 2015), Calculated			
Disposal Cost (2022$)	EPA, 2022					
Lamp Cost (2022$/klm)	2016 EIA Reference Case; Calculated		Calculated	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		
System (l/b/f) Cost (2022$/klm)						
Labor Cost (2022$/h)	2016 EIA Reference Case		Chapter 9; Section 9.2.2.1 of HID Final Determination TSD (DOE, 2015)			
Labor System Installation (hours)			2022 RS Means Online			
Labor Lamp Change (hours)						
Total Installed Cost (2022$)	Calculated					
Annual Maintenance Cost (2022$)						
Total Installed Cost (2022$/klm)						
Annual Maintenance Cost (2022$/klm)						

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Data Sources » Commercial T5 4xF54 HO High-bay

Final

DATA SOURCES	2012	2018	2022		2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	Assume Unchanged	Distributor Websites or Product Catalogs		Calculated					
Lamp Lumens					Assume Unchanged					
Lamp Efficacy (lm/W)					Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage										
System Lumens										
System Efficacy (lm/W)										
Ballast Efficiency (BLE)			GSFL Ballast Final Rule TSD (DOE, 2020)		Assume Unchanged					
CRI			Distributor Websites or Product Catalogs							
Correlated Color Temperature (CCT)										
Average Lamp Life (thousand hours)			Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017		DOE, 2017							
Lamp Price (2022$)	2016 EIA Reference Case; Calculated		Distributor Websites or Product Catalogs							
Ballast Price (2022$)										
Fixture Price (2022$)			Chapter 7 & Appendix 6A; Table 6A.3.4 of HID Final Determination TSD (DOE, 2015), Calculated							
Disposal Cost (2022$)	EPA, 2022									
Lamp Cost (2022$/klm)	2016 EIA Reference Case; Calculated		Calculated		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System (l/b/f) Cost (2022$/klm)										
Labor Cost (2022$/h)	2016 EIA Reference Case		2022 RS Means Online							
Labor System Installation (hours)										
Labor Lamp Change (hours)										
Total Installed Cost (2022$)	Calculated									
Annual Maintenance Cost (2022$)										
Total Installed Cost (2022$/klm)										
Annual Maintenance Cost (2022$/klm)										

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Data Sources » Commercial LED High-bay Luminaire

Final

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A										
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	N/A	Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency		N/A		N/A							
CRI		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs		Assume Unchanged					
Correlated Color Temperature (CCT)											
Average Lifetime (thousand hours)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017							
Lamp or Luminaire Price (2022$)	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	N/A	Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A		N/A							
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)		Calculated		Calculated		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Labor Cost (2022$/h)		2016 EIA Reference Case		2022 RS Means Online							
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)	Calculated			Calculated							
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

Refrigeration

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Data Sources » Commercial Compressor Rack Systems

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)	ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Median Store Size (ft^2)	Food Marketing Institute (FMI), 2012	CBECS 2018										
Power Input (kW)	Copeland, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use (MMWh/y)	ADL, 1996 / NCI Analysis, 2015	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Indexed Annual Efficiency	Calculated											
Average Life (years)	Kysor-Warren, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$)	NCI, 2009 / NCI Analysis, 2012	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Condensers

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)	NCI Analysis, 2008 / Heatcraft, 2008 / ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Median Store Size (ft^2)	Food Marketing Institute (FMI), 2012	CBECS 2018										
Power Input (kW)	NCI Analysis, 2008 / Heatcraft, 2008 / ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use (MMWh/y)	NCI Analysis, 2008 / ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Indexed Annual Efficiency	Calculated											
Average Life (years)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$)	NCI Analysis, 2008 / Heatcraft, 2008 / RS Means, 2007	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Supermarket Display Cases

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	ENERGY STAR	High	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Median Store Size (ft²)	Food Marketing Institute (FMI), 2012	CBECS 2018										
Case Length (ft)	DOE, 2016: CRE Report / Guidehouse Analysis 2022											
Annual Energy Use (kWh/y)[1,2]	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use / Case Length (kWh/ft)	Calculated											
Indexed Annual Efficiency[3]	Calculated											
Average Life (years)	DOE, 2007 / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / The Restaurant Store										
Total Installed Cost (2022$)	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)[4]	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Reach-In Refrigerators

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CREReport										
Size (ft^3)	ADL, 1996 / Distributor Web Sites	DOE, 2014: CREReport										
Annual Energy Use (kWh/y)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022										
Annual Energy Use / Volume (kWh/y/ft^3)	NCI Analysis, 2012	Calculated										
Indexed Annual Efficiency	Calculated											
Average Life (years)	Calculated											
Retail Equipment Cost (2022$)	ACEEE, 2002	DOE, 2014: CRE TSD										
Total Installed Cost (2022$)	ADL, 1996/ Distributor Web Sites / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022 / The Restaurant Store										
Total Installed Cost (2022$/kBtu/h)	Distributor Web Sites / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$)	Calculated											
Annual Maintenance Cost (2022$/kBtu/h)	NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Reach-In Freezers

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	ADL, 1996 / NCI Analysis, 2008	DOE, 2016: CRE Report										
Size (ft^3)	ADL, 1996 / Distributor Web Sites	DOE, 2016: CRE Report										
Annual Energy Use (kWh/y)	ADL, 1996 / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use / Volume ($kWh/y/ft^3$)	NCI Analysis, 2012	Calculated										
Indexed Annual Efficiency	Calculated											
Average Life (years)	ACEEE, 2002	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996/ Distributor Web Sites / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022 / The Restaurant Store										
Total Installed Cost (2022$)	Distributor Web Sites / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Walk-In Refrigerators

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE CRE Report 2016/CCMS 2022/Guidehouse Analysis 2022											
Size (ft^2)	DOE 2014 WICF TSD/Guidehouse Analysis 2022											
Annual Energy Use (kWh/y)	ADL, 1996/PG&E, 2004/NCI Analysis, 2008	DOE CRE Report 2016/Guidehouse Analysis 2022										
Annual Energy Use/Area ($kWh/ft^2/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Insulated Box Average Life (years)	ADL, 1996/PG&E, 2004	DOE CRE Report 2016/Guidehouse Analysis 2022										
Compressor Average Life (years)	ADL, 1996/PG&E, 2004	DOE CRE Report 2016/Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996/Distributor Web Sites/NCI Analysis, 2008	DOE CRE Report 2016/Webstaurant 2022/Guidehouse Analysis 2022										
Total Installed Cost (2022$)	ADL, 1996/Distributor Web Sites/NCI Analysis, 2008	DOE CRE Report 2016/Webstaurant 2022/Guidehouse Analysis 2023										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	ADL, 1996/FMI, 2005/NCI Analysis, 2008	DOE CRE Report 2016/Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Walk-In Freezers

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	ADL, 1996 / NCI Analysis, 2008	DOE CRE Report 2016 / CCMS 2022 / Guidehouse Analysis 2022										
Size (ft^2)	ADL, 1996 / NCI Analysis, 2008	Guidehouse Analysis 2022										
Annual Energy Use (kWh/y)	ADL, 1996 / PG&E, 2004 / NCI Analysis, 2008	Guidehouse CRE Report 2016										
Annual Energy Use / Area ($kWh/ft^2/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Insulated Box Average Life (years)	ADL, 1996 / PG&E, 2004	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Compressor Average Life (years)	ADL, 1996 / PG&E, 2004	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996 / Distributor Web Sites / NCI Analysis, 2008	DOE CRE Report 2016 / Webstaurant 2022 / Guidehouse Analysis 2022										
Total Installed Cost (2022$)	ADL, 1996 / Distributor Web Sites / NCI Analysis, 2008	DOE CRE Report 2016 / Webstaurant 2022 / Guidehouse Analysis 2023										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	DOE CRE Report 2016 / Guidehouse Analysis 2022											
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Ice Machines

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Output (pounds [lbs] per day)	ADL, 1996 / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022 / CCMS Database 2022										
Water Use per Hundred Pounds (gal/hundred lbs)	ADL, 1996 / Distributor Web Sites	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022 / CCMS Database 2022										
Energy Use per Hundred Pounds (kWh/hundred lbs)	ADL, 1996 / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Annual Energy Use (kWh/y)	ACEEE, 2002 / NCI Analysis, 2012	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022 / ENERGY STAR										
Indexed Annual Efficiency	Calculated											
Average Life (years)	ADL, 1996 / Distributor Web Sites / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Retail Equipment Cost (2022$)	Distributor Web Sites / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Total Installed Cost (with Bin)	NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	ADL, 1996 / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Beverage Merchandisers

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE, 2014: CRE Report / Guidehouse Analysis 2022											
Size (ft^3)	ADL, 1996 / Distributor Web Sites	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use (kWh/y)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022										
Annual Energy Use / Volume ($kWh/ft^3/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Average Life (years)	ACEEE, 2002	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996 / Distributor Web Sites	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / KaTom Restaurant Supply										
Total Installed Cost (2022$)	DOE, 2014: CRE Report / Guidehouse Analysis 2022											
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	DOE, 2014: CRE Report / Guidehouse Analysis 2022											
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources » Commercial Refrigerated Vending Machines

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE, 2015: BVMTSD / Guidehouse Analysis, 2015	DOE, 2022: BVMTSD / Guidehouse Analysis, 2022										
Can Capacity	DOE, 2015: BVMTSD	DOE, 2022: BVMTSD										
Size (ft^3)	DOE, 2022: BVMTSD / Guidehouse Analysis, 2022											
Annual Energy Use (kWh/y)	DOE, 2015: BVMTSD	DOE, 2022: BVMTSD										
Annual Energy Use / Volume ($kWh/ft^3/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Average Life (years)	DOE, 2015: BVMTSD	DOE, 2022: BVMTSD										
Retail Equipment Cost (2022$)	DOE, 2015: BVMTSD	DOE, 2022: BVMTSD										
Total Installed Cost (2022$)	DOE, 2015: BVMTSD	DOE, 2022: BVMTSD										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	DOE, 2015: BVMTSD / Guidehouse Analysis, 2015	DOE, 2022: BVMTSD / Guidehouse Analysis, 2022										
Annual Maintenance Cost (2022$/kBtu/h)	DOE, 2022: BVMTSD / Guidehouse Analysis, 2022											

Commercial Ventilation

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Data Sources » Commercial Constant Air Volume Ventilation

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
System Airflow (CFM)	CBECS 2003 & BED 2007	CBECS 2018										
System Fan Power (kW)	ASHRAE 90.1-2007	ASHRAE 90.1-2016	ASHRAE 90.1-2019	ASHRAE 90.1 2019 / Guidehouse Analysis 2022								
Specific Fan Power (W/CFM)												
Annual Fan Energy Use (kWh/y)												
Average Life (years)	ASHRAE: Service Life Database											
Total Installed Cost (2022$)	2022 RS Means Online											
Annual Maintenance Cost (2022$)	2022 RS Means Online / Guidehouse											
Total Installed Cost (2022$/thousand CFM)	Calculated											
Annual Maintenance Cost (2022$/thousand CFM)	Calculated											

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Data Sources » Commercial Variable Air Volume Ventilation

Final

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
System Airflow (CFM)	CBECS 2003 & BED 2007	CBECS 2018										
System Fan Power (kW)	ASHRAE 90.1-2007	ASHRAE 90.1-2016	ASHRAE 90.1-2019	ASHRAE 90.1 2019 / Guidehouse Analysis 2022								
Specific Fan Power (W/CFM)												
Annual Fan Energy Use (kWh/y)												
Average Life (years)	ASHRAE: Service Life Database											
Total Installed Cost (2022$)	2022 RS Means Online											
Annual Maintenance Cost (2022$)	2022 RS Means Online / Guidehouse											
Total Installed Cost (2022$/thousand CFM)	Calculated											
Annual Maintenance Cost (2022$/thousand CFM)	Calculated											

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Data Sources » Commercial Fan Coil Unit

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DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
System Airflow (CFM)	Product Literature											
System Fan Power (kW)	ASHRAE 90.1-2007	ASHRAE 90.1-2016	ASHRAE 90.1-2019	ASHRAE 90.1 2019 / Guidehouse Analysis 2022								
Specific Fan Power (W/CFM)												
Annual Fan Energy Use (kWh/y)												
Average Life (years)	ASHRAE: Service Life Database											
Total Installed Cost (2022$)	2022 RS Means Online											
Annual Maintenance Cost (2022$)	2022 RS Means Online / Guidehouse											
Total Installed Cost (2022$/thousand CFM)	Calculated											
Annual Maintenance Cost (2022$/thousand CFM)	Calculated											

Appendix B
References

Guidehouse
1200 19th Street, NW, Suite 700
Washington, D.C. 20036

And

Leidos
11951 Freedom Drive
Reston, VA 20190

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APPENDIX D

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Final

EIA - Technology Forecast Updates – Residential and Commercial Building Technologies – Advanced Case

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October 2022

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Objective

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The objective of this study is to develop baseline and projected performance and cost characteristics for residential and commercial end-use equipment in an Advanced Case that assumes accelerated adoption of energy-saving technologies due to increased R&D funding and market incentives.

- Examine 2012 and 2018 (commercial) and 2015 and 2020 (residential) baselines, as well as this year's baseline (2022).
  - Review literature, standards, installed base, contractor, and manufacturer information.
  - Provide a relative comparison and characterization of the cost and efficiency of a generic product.
- Forecast technology improvements that are projected to be available through 2050.
  - Review trends in standards, product enhancements, and research and development (R&D).
  - Project impact of product improvements and technology enhancement.

The performance and cost characterization of end-use equipment developed in this study will assist EIA in projecting national primary energy consumption.

Methodology

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Input from industry stakeholders, including government, R&D organizations, and manufacturers, was used to project product enhancements concerning equipment performance and cost attributes.

- Technology forecasting involves many uncertainties.
- Technology developments affect performance and cost forecasts.
- Varied sources ensure a balanced view of technology progress and the probable timing of commercial availability.

Definitions

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The following tables represent the current and projected efficiencies for residential and commercial building equipment ranging from the installed base in 2012 and 2018 (for commercial products) and 2015 and 2020 (for residential) to the highest efficiency equipment that is expected to be commercially available by 2050, assuming incremental adoption. Below are definitions for the terms used in characterizing the status of each technology.

- **Installed Stock Average**: the installed and *in use* equipment for that year. Represents the installed stock of equipment, but does *not* represent sales.
- **Current Standard**: the minimum efficiency (or maximum energy use) required (allowed) by current U.S. Department of Energy (DOE) standards, when applicable. For lighting, if no product exists at the standard efficiency level, a hypothetical wattage and lumen output is given for the standard's efficiency level.
- **ENERGY STAR®**: the minimum efficiency required (or maximum energy use allowed) to meet the ENERGY STAR® criteria, when applicable. Presented performance data represents certified products just meeting current ENERGY STAR specifications. For lighting, if no products exist at the ENERGY STAR efficiency level, a hypothetical wattage and lumen output is given for the ENERGY STAR efficiency level.
- **Low**: The minimum efficiency product or product mix available on the market. This rating typically reflects minimal compliance with DOE standards.
- **Typical**: the average, or typical, product being sold in the particular timeframe.
- **High**: the product with the highest efficiency available in the particular timeframe.
- **Lumens (lm):** the unit for luminous flux used in the SI unit system. This unit is used to indicate a light source's light output. All reported lumens are initial lumens. 1 kilolumen (klm) = 1,000 lumens.
- **Correlated Color Temperature (CCT)**: a specification of the color appearance of the light emitted by a lamp. Note: CCT is not a performance metric.
- **Color Rendering Index (CRI)**: a scale from 0 to 100 percent indicating how accurate a given light source is at rendering color when compared to a reference light source. The higher the CRI, the better the color rendering ability.
- **British thermal unit (Btu)**: a measure of the heat content of fuels or energy sources. It is the quantity of heat required to raise the temperature of one pound of liquid water by 1°F at the temperature that water has its greatest density (approximately 39 °F). 1 kBtu = 1,000 Btu.
- **Cubic Feet per Minute (CFM)**: a measure of airflow volume equal to the number of cubic feet of air flowing through a two-dimensional plane in one minute.
- **Not Available (N/A)**: data is not available where indicated.

Calculations

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The following metrics are commonly referred to throughout the tables to follow. Below are the calculations for each metric

- **Lighting**
  - **System Wattage** = (Lamp Wattage * Ballast Factor) / Ballast Efficiency
  - **System Lumens** = Lamp Lumens * Ballast Factor
  - **Lamp Efficacy** = Lamp Lumens / Lamp Wattage
  - **System Efficacy** = System Lumens / System Wattage
  - **Lamp Cost ($/klm)** = Lamp Cost / (Lamp Lumens / 1,000)
  - **Total Equipment Cost** = Lamp Cost + Fixture (including ballast) Cost
  - **System Cost ($/klm)** = Total Equipment Cost / (System Lumens / 1,000). l/b/f denotes that the cost includes the luminaire, the ballast, and the fixture.
  - **Total Installed Cost** = Total Equipment Cost + Labor Installation Cost
  - **Ballast Luminous Efficiency (BLE)** = A/(1+B*Avg Total Lamp Arc Power^(-C)) where A, B, and C are pre-defined constants by DOE Energy Conservation Standards for Fluorescent Lamp Ballasts.
- **Commercial Refrigeration**
  - **Nominal Capacity over Average Input (Btu in / Btu out)** = (Cooling or Heat Rejection Capacity)*24*365/(Annual Energy Consumption * 3,412)
  - **Total Installed Cost** = Retail Equipment Cost + Labor Installation Cost
  - **Total Installed Cost ($/kBtu/hour)** = Total Installed Cost*1,000 / (Cooling or Heat Rejection Capacity). h used as an abbreviation for hour throughout
  - **Annual Maintenance Cost ($/kBtu/h)** = Annual Maintenance Cost * 1,000 / (Cooling or Heat Rejection Capacity)
- **Ventilation**
  - **CFM out / Btu in / h** = System Airflow / (System Fan Power * 3,412)
  - **Total Installed Cost ($/1,000 CFM)** = Total Installed Cost * 1,000 / System Airflow
  - **Annual Maintenance Cost ($/1,000 CFM)** = Annual Maintenance Cost * 1,000 / System Fan Power

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Market Transformation

The market for the reviewed products has changed since this analysis was performed in 2015. These changes are noted and reflected in the efficiency and cost characteristics.

- DOE issued federal minimum efficiency standards that have gone into effect for General Service Fluorescent Lamps (2012), Incandescent Reflector Lamps (2012), and Fluorescent Lamp Ballasts (2019).

- In April 2022, DOE codified into the Code of Federal Regulations the 45 lumens per watt (lm/W) backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act (10 CFR 430, 87 FR 27439). This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

- DOE published a Final Rule updating energy conservation standards for Refrigerated Beverage Vending Machines at the end of 2015, effective in 2018. DOE also issued federal minimum efficiency standards that have or will soon go into effect for Refrigerated Beverage Vending Machines (2012), Automatic Commercial Ice Makers (2018), Walk-In Coolers and Freezers (2017), and Commercial Refrigeration Equipment (2017).

Residential Lighting

Note: More R&D investment and effort in the lighting industry only changes projections of LED technologies because additional funding and effort will likely not be applied to traditional technologies that have been exceeded in performance by their LED counterparts. Therefore, the inputs for all non-LED technologies remain unchanged from the Reference Case and are not included in this report.

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Performance and Cost Characteristics » Residential General Service Lamps

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The residential general service lamps characterized in this report are a 60-watt and a 75-watt medium screw-based (E26) A-type incandescent lamp and their halogen, CFL, and LED equivalents. A standard 60-watt incandescent lamp produces approximately 800 – 850 lumens. A standard 75-watt incandescent lamp produces approximately 1,100 lumens.

Performance:

- A majority of residential lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Fixture prices and installation costs are not included for the residential sector. Labor costs are assumed to be negligible because homeowners likely replaces lamps themselves as they burn out. Therefore, total installed cost is the price of a lamp, and annual maintenance costs are the cost of replacing the lamps, which is a function of lamp life, lamp price, and the annual operating hours.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Legislation:

- The Energy Independence and Security Act of 2007 (EISA 2007) established standards for 60-watt general service lamps, effective in 2014, and 75-watt lamps, effective in 2013. These standards cannot be achieved by incandescent bulbs, but can be by halogen, CFL, and LED technologies.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps. These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

ENERGY STAR:

- For ENERGY STAR qualification, general service omnidirectional lamps must have a minimum lamp efficacy of 70 lm/W for products with CRI ≥ 90 and 80 lm/W for lamps with CRI < 90. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

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Performance and Cost Characteristics » Residential General Service Lamps

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Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent, halogen, and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050:

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022.
CFL	+0.5%	0%	-0.5%	Improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps.

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Performance and Cost Characteristics » Residential General Service LED Lamps (60 W Incandescent Equivalent)

Higher efficacy compared with Reference Case

DATA	2015	2020	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	8.7	9.2	10.0	8.9	8.0	13.8	17.8	5.7	5.1	4.4	4.0	3.8	3.4
Lamp Lumens	656	803	800	800	800	800	800	800	800	800	800	800	800
Lamp Efficacy (lm/W)	75.5	87.1	80.0	90.0	100.0	80.0	45.0	141.5	157.2	180.2	200.2	209.0	232.1
CRI	81	85	80	81	90	80	N/A	81	90	81	90	81	90
Correlated Color Temperature (CCT)	2,700	2,700	2,700	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	25	21	15	14	18	15	N/A	14	18	14	18	14	18
Annual Operating Hours (h/y)	657	657	657	657	657	657	N/A	657	657	657	657	657	657
Lamp Price (2022$)	$13.53	$4.56	$6.20	$3.92	$5.32	$6.20	N/A	$3.23	$4.39	$2.84	$3.86	$2.46	$3.33
Lamp Cost (2022$/klm)	$20.63	$5.68	$7.75	$4.90	$6.65	$7.75	N/A	$7.02	$7.02	$3.57	$3.57	$2.38	$2.38
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	0.0	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$13.53	$4.56	$6.20	$3.92	$5.32	$6.20	N/A	$3.23	$4.39	$2.84	$3.86	$2.46	$3.33
Annual Maintenance Cost (2022$)	$0.35	$0.15	$0.27	$0.18	$0.19	$0.27	N/A	$0.15	$0.16	$0.13	$0.14	$0.11	$0.12
Total Installed Cost (2022$/klm)	$20.63	$5.68	$7.75	$4.90	$6.65	$7.75	N/A	$4.04	$5.49	$3.56	$4.83	$3.07	$4.17
Annual Maintenance Cost (2022$/klm)	$0.54	$0.18	$0.34	$0.22	$0.24	$0.34	N/A	$0.18	$0.20	$0.16	$0.17	$0.14	$0.15

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

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Performance and Cost Characteristics » Residential General Service Filament- LED Lamps (60 W Incandescent Equivalent)

Higher efficacy compared with Reference Case

DATA	2015	2020	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	9.7	7.1	5.5	6.9	8.0	13.8	17.8	5.4	5.1	4.2	4.0	3.6	3.4
Lamp Lumens	457	650	450	650	800	800	800	800	800	800	800	800	800
Lamp Efficacy (lm/W)	47.1	91.7	81.8	94.8	100.0	80.0	45.0	149.0	157.2	189.8	200.2	220.0	232.1
CRI	82	84	90	84	80	80	N/A	81	90	81	90	81	90
Correlated Color Temperature (CCT)	2,700	2,700	2,700	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	23	21	15	15	15	15	N/A	15	15	15	15	15	15
Annual Operating Hours (h/y)	657	657	657	657	657	N/A	N/A	657	657	657	657	657	657
Lamp Price (2022$)	$15.17	$6.88	$6.25	$5.91	$7.75	N/A	N/A	$4.87	$6.39	$4.29	$5.62	$3.70	$4.86
Lamp Cost (2022$/klm)	$33.20	$10.58	$13.89	$9.09	$9.69	N/A	N/A	$7.02	$7.02	$3.57	$3.57	$2.38	$2.38
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$15.17	$6.88	$6.25	$5.91	$7.75	N/A	N/A	$4.87	$6.39	$4.29	$5.62	$3.70	$4.86
Annual Maintenance Cost (2022$)	$0.43	$0.21	$0.27	$0.26	$0.34	N/A	N/A	$0.21	$0.28	$0.19	$0.25	$0.16	$0.21
Total Installed Cost (2022$/klm)	$33.20	$10.58	$13.89	$9.09	$9.69	N/A	N/A	$6.09	$7.99	$5.36	$7.03	$4.63	$6.07
Annual Maintenance Cost (2022$/klm)	$0.93	$0.33	$0.61	$0.40	$0.42	N/A	N/A	$0.27	$0.35	$0.23	$0.31	$0.20	$0.27

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

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Performance and Cost Characteristics » Residential Reflector Lamps

The residential reflector lamps characterized in this report are directional lamps that emit approximately 550 – 850 lumens (except for LED PAR38s which have outputs up to 1,700 lumens). Multiple baseline reflector lamps were analyzed, including 65W Incandescent BR30, Halogen PAR30, Halogen Infrared Reflector (HIR) PAR30, CFL BR30, LED BR30, and LED PAR38.

Performance:

- A majority of residential lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but for CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy.
- Fixture prices and installation costs are not included for the residential sector. Labor costs are assumed to be negligible because homeowners likely replaces lamps themselves as they burn out. Therefore, total installed cost is the price of a lamp, and annual maintenance costs are the cost of replacing the lamps, which is a function of lamp life, lamp price, and the annual operating hours.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Legislation:

- EPAct92 established minimum performance standards for some reflector lamps and provided exemptions for certain specialty applications (e.g., ER/BR, vibration service, more than 5% neodymium oxide, impact resistant, infrared heat, colored). EPAct92 effectively phased-out R-shaped tungsten filament incandescent reflector lamps at certain wattages and bulb diameters, replacing them with more efficient and cost effective tungsten-halogen parabolic aluminized reflector (PAR) lamps. EISA 2007 took away certain exemptions from EPACT 1992, requiring certain previously exempted lamps to meet EPAct92 minimum performance standards by January 1, 2008. The 65W BR30, a large majority of the incandescent reflector lamp market, was still exempted until 2022.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. **This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps.** These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

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Performance and Cost Characteristics » Residential Reflector Lamps

ENERGY STAR:

- For ENERGY STAR qualification, general service, reflector lamps must have a minimum lamp efficacy of 61 lm/W for products with CRI ≥ 90 and 70 lm/W for lamps with CRI < 90, respectively. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022.
CFL	+0.5%	0%	-0.5%	In addition to higher efficiency reflector coatings, improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Residential Reflector LED BR30

Final

Higher efficacy compared with Reference Case

DATA	2015	2020	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	14.2	10.9	11.0	8.8	7.2	10.7	14.4	5.5	4.7	4.8	4.1	4.2	3.7
Lamp Lumens	706	781	800	683	650	650	650	650	650	650	650	650	650
Lamp Efficacy (lm/W)	49.8	71.5	72.7	78.6	90.3	61.0	45.0	119.2	137.0	136.3	156.7	153.4	176.3
CRI	82	85	92	87	90	80	N/A	87	90	87	90	87	90
Correlated Color Temperature (CCT)	2,700	2,700	2,700	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	25	25	25	19	18	15	N/A	19	18	19	18	19	18
Annual Operating Hours (h/y)	730	730	730	730	730	N/A	N/A	730	730	730	730	730	730
Lamp Price (2022$)	$21.40	$15.36	$4.09	$5.01	$5.96	N/A	N/A	$4.11	$4.89	$3.62	$4.31	$3.14	$3.74
Lamp Cost (2022$/klm)	$30.31	$19.66	$5.11	$7.33	$9.17	N/A	N/A	$6.32	$7.53	$5.57	$6.64	$4.83	$5.75
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$21.40	$15.36	$4.09	$5.01	$5.96	N/A	N/A	$4.11	$4.89	$3.62	$4.31	$3.14	$3.74
Annual Maintenance Cost (2022$)	$0.63	$0.45	$0.12	$0.20	$0.24	N/A	N/A	$0.16	$0.19	$0.14	$0.17	$0.12	$0.15
Total Installed Cost (2022$/klm)	$30.31	$19.66	$5.11	$7.33	$9.17	N/A	N/A	$6.32	$7.53	$5.57	$6.64	$4.83	$5.75
Annual Maintenance Cost (2022$/klm)	$0.89	$0.57	$0.15	$0.29	$0.37	N/A	N/A	$0.25	$0.30	$0.22	$0.26	$0.19	$0.23

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

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Performance and Cost Characteristics » Residential Reflector LED PAR38

Final

Higher efficacy compared with Reference Case

DATA	2015	2020	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	19.2	15.5	17.0	16.4	17.0	10.7	29.9	10.8	11.2	9.4	9.8	8.4	8.7
Lamp Lumens	1,202	1,211	1,200	1,344	1,700	650	1,344	1,344	1,700	1,344	1,700	1,344	1,700
Lamp Efficacy (lm/W)	62.7	77.9	70.6	82.0	100.0	61.0	45.0	124.5	151.7	142.4	173.6	160.2	195.3
CRI	83	86	82	86	82	80	N/A	86	86	86	86	86	86
Correlated Color Temperature (CCT)	3,000	3,000	2,700	3,000	3,000	2,700	N/A	3,000	3,000	3,000	3,000	3,000	3,000
Average Lamp Life (thousand hours)	24	27	25	27	25	15	N/A	27	25	27	25	27	25
Annual Operating Hours (h/y)	730	730	730	730	730	N/A	N/A	730	730	730	730	730	730
Lamp Price (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Lamp Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Annual Maintenance Cost (2022$)	$1.07	$0.60	$0.69	$0.62	$0.46	N/A	N/A	$0.52	$0.38	$0.46	$0.34	$0.41	$0.31
Total Installed Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Annual Maintenance Cost (2022$/klm)	$0.89	$0.49	$0.58	$0.46	$0.27	N/A	N/A	$0.39	$0.23	$0.35	$0.20	$0.31	$0.18

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress presed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023, and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

Final

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Performance and Cost Characteristics » Residential 4-foot Linear 2-Lamp Lighting Systems

This section characterizes commercial linear fixtures that house two 4ft long linear lamps and their integrated luminaire equivalents. The technologies available for this system are linear fluorescent and LED.

- T5 lamps are approximately 40% narrower than T8 lamps and almost 60% narrower than T12 lamps. This narrowness allows T5 lamps to be coated with higher quality, more efficient phosphor blends than larger diameter lamps, resulting in a more efficacious lamp. The compact size of T5 lamps also permits greater flexibility in lighting design and construction.
- LED options for linear fixtures include replacement lamps that can fit directly into an existing fixture and fully integrated luminaires that can be used to replace existing fixtures. LED replacement lamps are also known as TLEDs. Type A TLEDs can be installed with existing ballasts and Type B and C TLEDs require the ballast to be disconnected. Replacement lamps are only sold to go into existing fixtures. If a new fixture is to be installed, a fully integrated LED luminaire is a more cost effective and efficient option. Because LED luminaires are fully integrated, they do not have lamp and fixture efficiency losses associated with ballasts and fixture optics.

Performance:

- Residential linear lamps often have a nominal CCT rating of 3500K, but products with CCTs of 3000K, 4000K, and 4100K (neutral white) are also common. 5000K (daylight) lamps are available as well. When replacing a light bulb, it is important to choose a product with a similar CCT value to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps, including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps. which are sold only as a replacement for use in an existing fixture. The LED luminaire is more efficient and cost effective for new installations or fixture retrofits.
- Labor costs for lamp changes are assumed to be negligible because homeowners likely replace lamps themselves as they burn out. Therefore, annual maintenance costs are the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for residential linear systems.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Legislation:

- Beginning July 14, 2012 (or July 14, 2014, for T8 700-series phosphor lamps), DOE fluorescent lamp standards required a minimum efficacy of 89 lm/W. Although the amended performance-based standards do not explicitly prohibit T12 lamps, no T12 lamps met the standard at the time of its announcement. Since then, however, T12 lamps meeting the standard have entered the market.
- Beginning November 14, 2014, DOE standards required that the characterized residential ballasts have a minimum BLE = 0.993 / (1 + 0.41 * Avg Total Lamp Arc power ^ (- 0.25)). Residential ballasts also must have a minimum power factor of 0.5.
- California's Title 24 mandates the use of electronic ballasts with high efficacy luminaires (including fluorescent) of 13 W or higher (CEC, 2005).

ENERGY STAR:

- ENERGY STAR does not cover linear lamps. (ENERGY STAR, 2020)

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Performance and Cost Characteristics » Residential 4-foot Linear 2-Lamp Lighting Systems

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume that manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050:

Technology	Efficacy	Lifetime	Price	Potential for Improvements
T12	0%	0%	-0.5%	Limited because the technology is mature.
T8	0%	0%	-0.5%	Limited because the technology is mature.
T5	0%	0%	-0.5%	Limited because the technology is mature.

Final

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Performance and Cost Characteristics » Residential Linear LED Replacement Lamp 2-Lamp System

Higher efficacy compared with Reference Case

DATA	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	18.5	16.3	16.0	13.7	11.0	8.9	7.2	7.7	7.2	7.7	7.2
Lamp Lumens	2,013	2,130	1,800	1,920	1,800	1,920	1,800	1,920	1,800	1,920	1,800
Lamp Efficacy (lm/W)	111.0	130.7	112.5	140.1	163.6	216.1	250.0	250.0	250.0	250.0	250.0
System Wattage	36.9	32.6	32.0	27.4	22.0	17.8	14.4	15.4	14.4	15.4	14.4
System Lumens	3,583	4,004	3,456	3,686	3,456	3,686	3,456	3,686	3,456	3,686	3,456
System Efficacy (lm/W)	97.0	122.8	108.0	134.5	157.1	207.4	240.0	240.0	240.0	240.0	240.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	83	81	82	81	80	81	80	81	80	81	80
Correlated Color Temperature (CCT)	4,100	3,500	4,100	4,100	5,000	4,100	5,000	4,100	5,000	4,100	5,000
Average Lamp Life (thousand hours)	55	50	50	54	50	54	50	54	50	54	50
Annual Operating Hours (h/y)	584	584	584	584	584	584	584	584	584	584	584
Lamp Price (2022$)	$27.00	$12.89	$14.63	$11.11	$4.28	$9.97	$3.84	$9.87	$3.80	$9.77	$3.77
Ballast Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$13.41	$6.05	$8.13	$5.79	$2.38	$5.19	$2.13	$5.14	$2.11	$5.09	$2.09
System (l/b/f) Cost (2022$/klm)	$15.07	$6.44	$8.47	$6.03	$2.48	$5.41	$2.22	$5.35	$2.20	$5.30	$2.18
Labor Cost (2022$/h)[2]	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor System Installation (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$54.00	$25.78	$29.26	$22.22	$8.56	$19.95	$7.68	$19.74	$7.60	$19.55	$7.53
Annual Maintenance Cost (2022$)	$0.57	$0.30	$0.34	$0.24	$0.10	$0.22	$0.09	$0.21	$0.09	$0.21	$0.09
Total Installed Cost (2022$/klm)	$15.07	$6.44	$8.47	$6.03	$2.48	$5.41	$2.22	$5.35	$2.20	$5.30	$2.18
Annual Maintenance Cost (2022$/klm)	$0.16	$0.08	$0.10	$0.07	$0.03	$0.06	$0.03	$0.06	$0.03	$0.06	$0.03

1. N/A because a fixture and an LED replacement lamp would not be purchased separately for a new installation or retrofit when there are integrated LED luminaires that are more efficient and cost effective. These lamps are sold only as replacements to go into existing fixtures.

Assume no labor is associated with lamp replacement in the residential sector because residents likely replace the lamps themselves.

Final

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Performance and Cost Characteristics » Residential Linear LED Luminaire

Higher efficacy compared with Reference Case

DATA	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	50.0	43.1	49.0	44.0	35.0	27.4	21.8	23.0	19.2	21.2	19.2
System Lumens	4,615	4,945	5,024	5,302	4,800	5,302	4,800	5,302	4,800	5,302	4,800
System Efficacy (lm/W)	92.3	114.7	102.5	120.5	137.1	193.4	220.1	230.4	250.0	250.0	250.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	83	82	80	79	80	79	80	79	80	79	80
Correlated Color Temperature (CCT)	3,838	3,000	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Average Lamp Life (thousand hours)	56	58	54	53	50	53	50	53	50	53	50
Annual Operating Hours (h/y)	730	730	730	730	730	730	730	730	730	730	730
Lamp or Luminaire Price (2022$)	$181.60	$158.60	$144.85	$152.54	$207.80	$121.11	$164.98	$105.34	$143.50	$90.11	$122.76
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$78.70	$64.15	$57.66	$57.54	$86.58	$45.68	$68.74	$39.74	$59.79	$33.99	$51.15
Labor Cost (2022$/h)	$80.90	$80.90	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$403.65	$357.65	$322.70	$338.08	$448.60	$275.22	$362.97	$243.68	$320.01	$213.23	$278.52
Annual Maintenance Cost (2022$)	$2.89	$2.49	$2.40	$2.56	$3.52	$2.12	$2.89	$1.91	$2.58	$1.70	$2.27
Total Installed Cost (2022$/klm)	$87.46	$72.33	$64.23	$63.76	$93.46	$51.91	$75.62	$45.96	$66.67	$40.22	$58.03
Annual Maintenance Cost (2022$/klm)	$0.63	$0.50	$0.48	$0.48	$0.73	$0.40	$0.60	$0.36	$0.54	$0.32	$0.47

1. N/A because the lamp and fixture are both included in the luminaire.

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Performance and Cost Characteristics » Residential Outdoor Lamps

Final

- The residential outdoor lamps characterized in this report include reflector and general service lamps used for security and/or porch lighting that can be switched on from inside the home (i.e. parking lot/garage and outdoor common area lighting at multifamily buildings are excluded) with lumen outputs of approximately 1,000 – 1,400 lumens. Multiple baseline lamps were analyzed according to estimates of installed base average lumens by lamp type, including:

Security (Reflector Lamps)	Porch (General Service Lamps)
Incandescent BR30	Incandescent A-Type
Halogen PAR38	Halogen A-Type
Halogen Infrared Reflector (HIR) PAR38	CFL Bare Spiral
CFL PAR38	LED A-Type Lamp
LED PAR38	

Performance:

- 65W BR30 is the only viable incandescent reflector lamp due to exemption from EISA 2007. The lumen output of this lamp type is well below other reflector lamp technologies characterized for residential outdoor spaces, thus its use is limited for this application. This product is, as of 2022, expected to be eliminated by DOE's 45 lm/W backstop requirement.
- A majority of residential lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2015 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Fixture prices and installation costs are not included for the residential sector. Labor costs are assumed to be negligible because homeowners likely replaces lamps themselves as they burn out. Therefore, total installed cost is the price of a lamp, and annual maintenance costs are the cost of replacing the lamps, which is a function of lamp life, lamp price, and the annual operating hours for residential reflector lamps.
- Disposal costs are not characterized for residential lighting in this analysis. In residential cases, disposal is done by the occupant. Lamp and product burnout are assumed to result in no "added" cost aside from the work performed to install the replacement.

Final

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Performance and Cost Characteristics » Residential Outdoor Lamps

Legislation:

- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. **This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps.** These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

ENERGY STAR:

- For ENERGY STAR qualification, general service omnidirectional lamps must have a minimum lamp efficacy of 70 lm/W for products with CRI ≥ 90 and 80 lm/W for lamps with CRI < 90.
- For ENERGY STAR qualification, general service reflector lamps must have a minimum lamp efficacy of 61 lm/W for products with CRI ≥ 90 and 70 lm/W for lamps with CRI < 90.
- Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent Omnidirectional	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Incandescent Directional	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
CFL	+0.5%	0%	-0.5%	In addition to benefiting from higher efficiency reflector coatings, improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Security: LED Reflector)

Higher efficacy compared with Reference Case

DATA	2015	2020	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	19.2	15.5	17.0	16.4	17.0	10.7	29.9	10.8	11.2	9.4	9.8	8.4	8.7
Lamp Lumens	1,202	1,211	1,200	1,344	1,700	650	1,344	1,344	1,700	1,344	1,700	1,344	1,700
Lamp Efficacy (lm/W)	62.7	77.9	70.6	82.0	100.0	61.0	45.0	124.5	151.7	142.4	173.6	160.2	195.3
CRI	83	86	82	86	82	80	N/A	86	86	86	86	86	86
Correlated Color Temperature (CCT)	3,000	3,000	2,700	3,000	3,000	2,700	N/A	3,000	3,000	3,000	3,000	3,000	3,000
Average Lamp Life (thousand hours)	24	27	25	27	25	15	N/A	27	25	27	25	27	25
Annual Operating Hours (h/y)	730	730	730	730	730	N/A	N/A	730	730	730	730	730	730
Lamp Price (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Lamp Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$35.23	$22.44	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Annual Maintenance Cost (2022$)	$1.07	$0.60	$0.69	$0.62	$0.46	N/A	N/A	$0.52	$0.38	$0.46	$0.34	$0.41	$0.31
Total Installed Cost (2022$/klm)	$29.31	$18.54	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
Annual Maintenance Cost (2022$/klm)	$0.89	$0.49	$0.58	$0.46	$0.27	N/A	N/A	$0.39	$0.23	$0.35	$0.20	$0.31	$0.18

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress presed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

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Performance and Cost Characteristics » Residential Outdoor Lamps (Porch: LED A-Type)

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Higher efficacy compared with Reference Case

DATA	2015	2020	2022				2023[1]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	12.9	11.8	13.5	11.9	11.0	13.6	24.4	7.6	7.0	6.0	5.5	5.1	4.7
Lamp Lumens	1,073	1,102	1,100	1,089	1,100	1,089	1,100	1,100	1,100	1,100	1,100	1,100	1,100
Lamp Efficacy (lm/W)	83.1	93.5	81.5	92.2	100.0	80	45.0	144.9	157.2	184.6	200.2	214.0	232.1
CRI	81	85	80	86	80	80	N/A	86	80	86	80	86	80
Correlated Color Temperature (CCT)	2,700	2,700	3,000	2,700	2,700	2,700	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	25	21	25	18	25	N/A	N/A	18	25	18	25	18	25
Annual Operating Hours (h/y)	657	657	657	657	657	N/A	N/A	657	657	657	657	657	657
Lamp Price (2022$)	$18.13	$8.48	$4.39	$3.92	$5.29	N/A	N/A	$3.23	$4.36	$2.84	$3.84	$2.46	$3.31
Lamp Cost (2022$/klm)	$16.90	$7.70	$3.99	$3.60	$4.81	N/A	N/A	$7.02	$7.02	$3.57	$3.57	$2.38	$2.38
Labor Cost (2022$/h)	$0.00	$0.00	$0.00	$0.00	$0.00	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Labor Lamp Installation (hours)	0.0	0.0	0.0	0.0	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0	0.0
Total Installed Cost (2022$)	$18.13	$8.48	$4.39	$3.92	$5.29	N/A	N/A	$3.23	$4.36	$2.84	$3.84	$2.46	$3.31
Annual Maintenance Cost (2022$)	$0.49	$0.27	$0.12	$0.14	$0.14	N/A	N/A	$0.12	$0.11	$0.10	$0.10	$0.09	$0.09
Total Installed Cost (2022$/klm)	$16.90	$7.70	$3.99	$3.60	$4.81	N/A	N/A	$2.94	$3.97	$2.59	$3.49	$2.23	$3.01
Annual Maintenance Cost (2022$/klm)	$0.45	$0.24	$0.10	$0.13	$0.13	N/A	N/A	$0.11	$0.10	$0.09	$0.09	$0.08	$0.08

1. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress presed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.

Commercial Lighting

Note: More R&D investment and effort in the lighting industry will only change future projections of LED technologies because additional funding and effort will likely not be applied to traditional technologies that have been exceeded in performance by their LED counterparts. Therefore, the inputs for all non-LED technologies remain unchanged from the Reference Case and are therefore not included in this report.
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Performance and Cost Characteristics » Commercial General Service Lamps in Recessed Can Fixtures

This section characterizes commercial omnidirectional incandescent, halogen, CFL, and LED screw-based general service lamps emitting approximately 1,600 lumens (equivalent to a 100W incandescent lamp) used in recessed can fixtures. A recessed can is a directional fixture set into the ceiling, in which all of the light is directed downwards from the opening. Therefore, an omnidirectional lamp is not well suited for use in such fixtures because light that emits upwards and out of the sides must be reflected downwards and out of the fixture and some light is absorbed in the process. A fixture efficiency of 61% is used to characterize these lumen losses for all omnidirectional lamps. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- A majority of general service lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps which are sold only as a replacement for use in an existing fixture. There are integrated LED luminaires that are more efficient and cost effective for new installations or fixture retrofits. Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy. Therefore typical lamp prices in 2015 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial general service lamps (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for high intensity discharge (HID) lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- The Energy Independence and Security Act of 2007 (EISA 2007) established standards for 100W lamps effective in 2012. These standards cannot be achieved by incandescent bulbs, but they can be met by halogen, CFL, and LED technologies from 2012 to 2023.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps. These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

ENERGY STAR:

- For ENERGY STAR qualification, general service omnidirectional lamps must have a minimum lamp efficacy of 70 lm/W for products with CRI ≥ 90 and 80 lm/W for lamps with CRI < 90. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

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Performance and Cost Characteristics » Commercial General Service Lamps in Recessed Can Fixtures

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022
CFL	+0.5%	0%	-0.5%	Improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Commercial General Service 100W Equivalent LED Replacement Lamp in Recessed Can Fixture

Higher efficacy compared with Reference Case

DATA	2012	2018	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[1]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	26.7	14.5	16.0	14.8	13.0	20.0	34.8	9.4	8.3	7.4	6.5	6.4	6.4
Lamp Lumens	1,600	1,528	1,600	1,567	1,600	1,600	1,567	1,567	1,600	1,567	1,600	1,567	1,600
Lamp Efficacy (lm/W)	60.0	105.1	100.0	106.0	123.1	80.0	45.0	166.7	193.5	212.2	246.4	246.1	250.0
System Wattage	26.7	14.5	16.0	14.8	13.0	20.0	34.8	9.4	8.3	7.4	6.5	6.4	6.4
System Lumens[3]	976	932	976	956	976	976	956	956	976	956	976	956	976
System Efficacy (lm/W)	36.6	64.1	61.0	64.7	75.1	48.8	27.5	101.7	118.0	129.5	150.3	150.1	152.5
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	80	80	90	84.8	84	80	N/A	84.8	84.8	84.8	84.8	84.8	84.8
Correlated Color Temperature (CCT)	3,000	3,000	2,700	2,700	5,000	N/A	N/A	2,700	2,700	2,700	2,700	2,700	2,700
Average Lamp Life (thousand hours)	22.0	17.9	25.0	16.9	25.0	15.0	N/A	16.9	25.0	16.9	25.0	16.9	25.0
Annual Operating Hours (h/y)	4,928	4,928	4,928	4,928	4,928	N/A	N/A	4,928	4,928	4,928	4,928	4,928	4,928
Lamp Price (2022$)	$47.45	$11.28	$5.62	$7.04	$3.39	N/A	N/A	$5.81	$2.80	$5.11	$2.46	$4.41	$2.12
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$26.38	$22.07	$22.07	$22.07	N/A	N/A	$21.20	$21.20	$20.17	$20.17	$19.18	$19.18
Lamp Cost (2022$/klm)	$25.00	$7.38	$3.51	$4.49	$2.12	N/A	N/A	$3.71	$1.75	$3.26	$1.54	$2.82	$1.33
System (l/b/f) Cost (2022$/klm)	$72.92	$40.40	$28.37	$30.46	$26.09	N/A	N/A	$28.26	$24.59	$26.45	$23.18	$24.68	$21.83
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	N/A	N/A	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.0	1.0	1.0	1.0	1.0	N/A	N/A	1.0	1.0	1.0	1.0	1.0	1.0
Labor Lamp Change (hours)	0.05	0.05	0.05	0.05	0.05	N/A	N/A	0.05	0.05	0.05	0.05	0.05	0.05
Total Installed Cost (2022$)	$148.39	$114.88	$93.69	$95.11	$91.46	N/A	N/A	$93.01	$90.00	$91.27	$88.63	$89.59	$87.30
Annual Maintenance Cost (2022$)	$11.49	$4.16	$1.76	$3.02	$1.32	N/A	N/A	$2.66	$1.20	$2.45	$1.14	$2.25	$1.07
Total Installed Cost (2022$/klm)	$152.04	$123.25	$95.99	$99.52	$93.71	N/A	N/A	$97.32	$92.21	$95.51	$90.81	$93.75	$89.45
Annual Maintenance Cost (2022$/klm)	$11.77	$4.46	$1.80	$3.16	$1.35	N/A	N/A	$2.78	$1.23	$2.57	$1.16	$2.35	$1.10

1. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress presed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. All LED lighting products exceed the new minimum efficacy standards.
3. Based on a fixture efficiency of 61% for an omnidirectional lamp installed in a recessed can fixture.

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Performance and Cost Characteristics » Commercial Reflector Lamps in Recessed Can Fixtures

This section characterizes commercial halogen, halogen infrared reflector (HIR), and LED screw-based reflector lamps emitting approximately 1400 lumens used in recessed can fixtures.

- HIR lamps contain a tungsten halogen capsule with a film coating on the inside of the capsule. The coating reflects infrared radiation back into the lamp filament, which forces the filament to burn at a higher temperature. This design increases the efficacy of the lamp, without reducing operating life.
- A recessed can is a directional fixture set into the ceiling, in which all of the light is directed downwards from the opening. Therefore, a reflector lamp, which employs reflective coating to direct light out in only one direction, is well suited for use in such fixtures. However, some light is not able to escape the fixture, and a fixture efficiency of 93% is used to characterize these minimal lumen losses. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- A majority of reflector lamps have a nominal CCT rating of 2,700K and give off a warm, yellowish white color, but products with CCTs of 3,000K, 3,500K, 4,100K (neutral white), 5,000K (daylight), and 6,500K (blueish white) are also available. Traditional incandescent light bulbs have a nominal CCT of about 2,700K. When replacing a light bulb, it is advised to chose a product with a similar CCT value in order to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100. However, CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination. High CRI products are preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these specific retail and display applications.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps which are sold only as a replacement for use in an existing fixture. Many factors influence the price of LED lamps including CRI, lifetime, dimming capabilities, and efficacy.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial reflector lamps (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- EPAct92 established minimum performance standards for some reflector lamps and provided exemptions for certain specialty applications (e.g., ER/BR, vibration service, more than 5% neodymium oxide, impact resistant, infrared heat, colored). EPAct92 effectively phased-out R-shaped tungsten filament incandescent reflector lamps at certain wattages and bulb diameters, replacing them with more efficient and cost effective tungsten-halogen parabolic aluminized reflector (PAR) lamps. EISA2007 took away certain exemptions from EPACT 1992, requiring certain previously exempted lamps to meet EPAct92 minimum performance standards by January 1, 2008. In 2015, DOE issued a final rule that determined that amending the standards for incandescent reflector lamps could not be economically justified.
- In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress prescribed in the Energy Policy and Conservation Act. **This action also amended the definition of general service lamps to include previously exempted product classes, such as reflector lamps.** These standards can not be achieved by traditional incandescent or halogen technologies currently on the market, and given current and projected trends in industry, they will likely not be met. It is currently assumed that industry will increase its investment in LED technology at the expense of incandescent, halogen, and CFL technologies. The rule will go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023.

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Performance and Cost Characteristics » Commercial Reflector Lamps in Recessed Can Fixtures

ENERGY STAR:

- For ENERGY STAR qualification, general service reflector lamps must have a minimum lamp efficacy of 61 lm/W for products with CRI ≥ 90 and 70 lm/W for lamps with CRI < 90. Additionally, the lamps must have a CRI ≥ 80, nominal CCT of 2,700, 3,000, 3,500, 4,000/4,100, 5,000, or 6,000 K, and rated lifetime ≥ 10,000 hours (ENERGY STAR).

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
Incandescent	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements.
Halogen	0%	0%	-0.5%	Limited because the technology is mature and the technology cannot meet legislative requirements as of 2022
CFL	+0.5%	0%	-0.5%	In addition to higher efficiency reflector coatings, improvements in efficacy can be made by using more rare-earth phosphors in compact fluorescent lamps. Lifetime improvements can be made by improving the compact fluorescent lamp electrodes.

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Performance and Cost Characteristics » Commercial LED Reflector Lighting (PAR38)

Higher efficacy compared with Reference Case

DATA	2012	2018	2022				2023[2]	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[3]	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	17.2	16.6	17.0	16.4	17.0	22.0	29.9	14.0	11.2	9.4	9.8	8.4	8.7
Lamp Lumens	1,045	1,210	1,200	1,344	1,700	1,344	1,344	1,344	1,700	1,344	1,700	1,344	1,700
Lamp Efficacy (lm/W)	60.9	73.0	70.6	82.0	100.0	61.0	45.0	95.7	151.7	142.4	173.6	160.2	195.3
System Wattage	17.2	16.6	17.0	16.4	17.0	22.0	29.9	14.0	11.2	9.4	9.8	8.4	8.7
System Lumens[1]	972	1,125	1,116	1,250	1,581	1,250	1,250	1,250	1,581	1,250	1,581	1,250	1,581
System Efficacy (lm/W)	56.6	67.9	65.6	76.1	93.0	56.7	41.9	89.0	141.1	132.4	161.4	149.0	181.6
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	83	83	82	86	82	80	N/A	86	82	86	82	86	82
Correlated Color Temperature (CCT)	3,000	3,000	2,700	3,000	3,000	3,000	N/A	3,000	3,000	3,000	3,000	3,000	3,000
Average Lamp Life (thousand hours)	22	15	25	28	25	25	N/A	28	25	28	25	28	25
Annual Operating Hours (h/y)	4,928	4,928	4,928	4,928	4,928	N/A	N/A	4,928	4,928	4,928	4,928	4,928	4,928
Lamp Price (2022$)	$61.98	$28.10	$23.71	$23.09	$15.69	N/A	N/A	$19.40	$13.18	$17.36	$11.79	$15.37	$10.45
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	$23.72	$26.38	$22.07	$22.07	$22.07	N/A	N/A	$21.20	$21.20	$20.17	$20.17	$19.18	$19.18
Lamp Cost (2022$/klm)	$59.31	$23.23	$19.76	$17.18	$9.23	N/A	N/A	$14.43	$7.75	$12.91	$6.94	$11.44	$6.14
System (l/b/f) Cost (2022$/klm)	$88.18	$48.42	$41.02	$36.13	$23.88	N/A	N/A	$32.48	$21.75	$30.02	$20.22	$27.64	$18.74
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	N/A	N/A	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.0	1.0	1.0	1.0	1.0	N/A	N/A	1.0	1.0	1.0	1.0	1.0	1.0
Labor Lamp Change (hours)	0.05	0.05	0.05	0.05	0.05	N/A	N/A	0.05	0.05	0.05	0.05	0.05	0.05
Total Installed Cost (2022$)	$162.93	$131.71	$111.78	$111.16	$103.76	N/A	N/A	$106.60	$100.38	$103.52	$97.96	$100.55	$95.63
Annual Maintenance Cost (2022$)	$14.75	$10.50	$5.32	$4.64	$3.74	N/A	N/A	$3.99	$3.25	$3.64	$2.98	$3.29	$2.71
Total Installed Cost (2022$/klm)	$167.64	$117.04	$100.16	$88.92	$65.63	N/A	N/A	$85.28	$63.49	$82.81	$61.96	$80.44	$60.48
Annual Maintenance Cost (2022$/klm)	$15.17	$9.33	$4.77	$3.72	$2.37	N/A	N/A	$3.20	$2.05	$2.91	$1.88	$2.63	$1.71

1. Based on a fixture efficiency of 93% for an omnidirectional lamp installed in a recessed can fixture.
2. In April 2022, DOE codified into the Code of Federal Regulations the 45 lm/W backstop requirement for general service lamps that Congress presed in the Energy Policy and Conservation Act. The new minimum efficacy requirements go into effect for manufacture and import in January 2023 and for retail and distribution in July 2023. This Final Rule also amended the definition of GSLs to include previously exempted product classes, including reflector lamps. All LED lighting products exceed the new minimum efficacy standards.
3. Criteria outlined in ENERGY STAR® Program Requirements Product Specification for Lamps (Light Bulbs): Eligibility Criteria Version 2.1 (Published June, 2017, Revised June 2020)

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Performance and Cost Characteristics » Commercial 4-foot Linear 2-Lamp Lighting Systems

This section characterizes commercial linear fixtures that house two 4ft long linear lamps and their integrated luminaire equivalents. The technologies available for this system are linear fluorescent and LED.

- Linear fluorescent options are T5, T8, and T12 lamps. T5 lamps are approximately 40% narrower than T8 lamps and almost 60% narrower than T12 lamps. This narrowness allows T5 lamps to be coated with higher quality, more efficient phosphor blends than larger diameter lamps, resulting in a more efficacious lamp. The compact size of T5 lamps also permits greater flexibility in lighting design and construction.
- LED options for linear fixtures include replacement lamps that can fit directly into an existing fixture and fully integrated luminaires that can be used to replace existing fixtures. LED replacement lamps are also known as TLEDs. Type A TLEDs can be installed with existing ballasts and Type B and C TLEDs require the ballast to be disconnected. Replacement lamps are only sold to go into existing fixtures. If a new fixture is to be installed, a fully integrated LED luminaire is a more cost effective and efficient option. Because LED luminaires are fully integrated, they do not have lamp and fixture efficiency losses associated with ballasts and fixture optics. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- Linear lamps often have a nominal CCT rating of 3,500K, but products with CCTs of 3,000K, 4,000K, and 4,100K (neutral white) are also common. 5,000K (daylight) lamps are available as well. When replacing a light bulb, it is important to choose a product with a similar CCT value to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- The total installed cost is the price of two lamps, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamp, which are sold only as a replacement for use in an existing fixture. There are integrated LED luminaires that are more efficient and cost effective for new installations or fixture retrofits. Many factors influence the price of LED lamps, including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2022, reflecting a mix of lamp characteristics and features, were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours of 4055 hours per year for commercial 4ft linear systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- Beginning July 14, 2012 (or July 14, 2014, for T8 700-series phosphor lamps), DOE fluorescent lamp standards required a minimum efficacy of 89 lm/W. Although the amended performance-based standards do not explicitly prohibit T12 lamps, no T12 lamps met the standard at the time of its announcement. Since then, however, T12 lamps meeting the standard have entered the market.
- California's Title 24 mandates the use of electronic ballasts with high efficacy luminaires (including fluorescent) of 13 W or higher (CEC, 2005).

ENERGY STAR:

- ENERGY STAR does not cover commercial linear luminaires (ENERGY STAR, 2020).

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Performance and Cost Characteristics » Commercial 4-foot Linear 2-Lamp Lighting Systems

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume that manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

Technology	Efficacy	Lifetime	Price	Potential for Improvements
T8 F32 Commodity	0%	0%	-0.5%	Limited because the technology is mature.
T8 F32 High Efficiency/High Output	0%	0%	-0.5%	Limited because the technology is mature.
T5 F28	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Commercial 4-ft Linear LED Replacement Lamp in 2-Lamp System

Higher efficacy compared with Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	20.8	17.0	16.0	13.7	11.0	8.9	7.2	7.7	7.2	7.7	7.2
Lamp Lumens	2,091	2,003	1,800	1,920	1,800	1,920	1,800	1,920	1,800	1,920	1,800
Lamp Efficacy (lm/W)	100.5	117.8	112.5	140.1	163.6	216.1	250.0	250.0	250.0	250.0	250.0
System Wattage	41.6	34.0	32.0	27.4	22.0	17.8	14.4	15.4	14.4	15.4	14.4
System Lumens	3,555	3,565	3,456	3,686	3,456	3,686	3,456	3,686	3,456	3,686	3,456
System Efficacy (lm/W)	85.4	104.9	108.0	134.5	157.1	207.4	240.0	240.0	240.0	240.0	240.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	86	81	82	81	80	81	80	81	80	81	80
Correlated Color Temperature (CCT)	4,100	4,020	4,100	3,500	5,000	3,500	5,000	3,500	5,000	3,500	5,000
Average Lamp Life (thousand hours)	50	54	50	54	50	54	50	54	50	54	50
Annual Operating Hours (h/y)	4,055	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541	3,541
Lamp Price (2022$)	$278.36	$35.06	$14.63	$11.11	$4.28	$9.88	$3.81	$9.66	$3.72	$9.44	$3.64
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	$133.10	$17.50	$8.13	$5.79	$2.38	$5.15	$2.11	$5.03	$2.07	$4.92	$2.02
System (l/b/f) Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total Installed Cost (2022$)	$587.35	$70.12	$29.26	$22.22	$8.56	$19.76	$7.61	$19.31	$7.44	$18.89	$7.28
Annual Maintenance Cost (2022$)	$47.63	$6.61	$3.93	$3.17	$2.46	$3.01	$2.39	$2.98	$2.38	$2.95	$2.37
Total Installed Cost (2022$/klm)	$165.20	$19.67	$8.47	$6.03	$2.48	$5.36	$2.20	$5.24	$2.15	$5.12	$2.11
Annual Maintenance Cost (2022$/klm)	$13.40	$1.85	$1.14	$0.86	$0.71	$0.82	$0.69	$0.81	$0.69	$0.80	$0.69

1. N/A because a fixture and an LED replacement lamp would not be purchased separately for a new installation or retrofit when there are integrated LED luminaires that are more efficient and cost effective. These lamps are sold only as replacements to go into existing fixtures.

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Performance and Cost Characteristics » Commercial 4-ft Linear LED Luminaire to Replace 2-Lamp Systems

Higher efficacy compared with Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	51.5	50.0	49.0	44.0	35.0	27.4	21.8	23.0	19.2	21.2	19.2
System Lumens	4,818	4,673	5,024	5,302	4,800	5,302	4,800	5,302	4,800	5,302	4,800
System Efficacy (lm/W)	93.6	93.5	102.5	120.5	137.1	193.4	220.1	230.4	250.0	250.0	250.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	84	79	80	79	80	79	80	79	80	79	80
Correlated Color Temperature (CCT)	3,500	3,650	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Average Lifetime (thousand hours)	67	53	54	53	50	53	50	53	50	53	50
Annual Operating Hours (h/y)	4,055	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431
Lamp or Luminaire Price (2022$)	$723.96	$188.00	$144.85	$152.54	$207.80	$127.58	$173.80	$118.37	$161.25	$109.57	$149.27
Ballast Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$150.25	$40.23	$57.66	$57.54	$86.58	$24.06	$36.21	$22.33	$33.59	$20.67	$31.10
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$762.57	$226.61	$322.70	$338.08	$448.60	$160.58	$206.80	$151.37	$194.25	$142.57	$182.27
Annual Maintenance Cost (2022$)	$46.16	$14.67	$11.30	$12.01	$16.52	$10.40	$14.19	$9.80	$13.33	$9.23	$12.51
Total Installed Cost (2022$/klm)	$158.27	$48.49	$64.23	$63.76	$93.46	$30.29	$43.08	$28.55	$40.47	$26.89	$37.97
Annual Maintenance Cost (2022$/klm)	$9.58	$3.14	$2.25	$2.27	$3.44	$1.96	$2.96	$1.85	$2.78	$1.74	$2.61

1. N/A because the lamp and fixture are both included in the luminaire.

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Performance and Cost Characteristics » Commercial 8-foot Linear 2-Lamp Lighting Systems

This section characterizes commercial linear fixtures that house two 8ft long linear lamps and their integrated luminaire equivalents. The technologies available for this system are linear fluorescent and LED.

- Linear fluorescent options are T5, T8, and T12 lamps. T5 lamps are approximately 40% narrower than T8 lamps and almost 60% narrower than T12 lamps. This narrowness allows T5 lamps to be coated with higher quality, more efficient phosphor blends than larger diameter lamps, resulting in a more efficacious lamp. The compact size of T5 lamps also permits greater flexibility in lighting design and construction.
- LED options for linear fixtures include replacement lamps that can fit directly into an existing fixture and fully integrated luminaires that can be used to replace existing fixtures. LED replacement lamps are also known as TLEDs. Type A TLEDs can be installed with existing ballasts and Type B and C TLEDs require the ballast to be disconnected. Replacement lamps are only sold to go into existing fixtures. If a new fixture is to be installed, a fully integrated LED luminaire is a more cost effective and efficient option. Because LED luminaires are fully integrated, they do not have lamp and fixture efficiency losses associated with ballasts and fixture optics. For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- Linear lamps often have a nominal CCT rating of 3,500K, but products with CCTs of 3,000K, 4,000K, and 4,100K (neutral white) are also common. 5,000K (daylight) lamps are available as well. When replacing a light bulb, it is important to choose a product with a similar CCT value to achieve the same look.
- Incandescent and halogen lamps have perfect color rendering with a CRI value of 100, but CFL and LEDs products commonly fall between 70 and 90 CRI, with an average around 80. CRI values of 80 are considered suitable for general illumination, with high CRI products being preferable for retail and display applications where improved color quality is of real value. Higher CRI is not expected to be a focus for future LED products except for these very specific retail and display applications.

Cost:

- The total installed cost is the price of two lamps, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED replacement lamps, which are sold only as a replacement for use in an existing fixture. There are integrated LED luminaires that are more efficient and cost effective for new installations or fixture retrofits. Many factors influence the price of LED lamps, including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical lamp prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours of 4147 hours per year for commercial 8ft linear systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

Legislation:

- Beginning July 14, 2012 (or July 14, 2014, for T8 700-series phosphor lamps), DOE fluorescent lamp standards required a minimum efficacy of 89 lm/W. Although the amended performance-based standards do not explicitly prohibit T12 lamps, no T12 lamps met the standard at the time of its announcement. Since then, however, T12 lamps meeting the standard have entered the market.
- California's Title 24 mandates the use of electronic ballasts with high efficacy luminaires (including fluorescent) of 13 W or higher (CEC, 2005).

ENERGY STAR:

- ENERGY STAR does not cover commercial linear luminaires (ENERGY STAR, 2020).

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Performance and Cost Characteristics » Commercial 8-foot Linear 2-Lamp Lighting Systems

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume that manufacturers will focus on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050:

Technology	Efficacy	Lifetime	Price	Potential for Improvements
T8 F59 Typical Efficiency	0%	0%	-0.5%	Limited because the technology is mature.
T8 F59 High Efficiency	0%	0%	-0.5%	Limited because the technology is mature.
T8 F96 High Output	0%	0%	-0.5%	Limited because the technology is mature.

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Performance and Cost Characteristics » Commercial 8-ft Linear LED Replacement Lamp for a 2-Lamp System

Final

Higher efficacy compared with Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	35.7	34.0	39.0	40.0	25.3	25.9	21.9	22.4	19.8	22.0
Lamp Lumens	N/A	3,975	4,200	4,960	5,500	4,960	5,500	4,960	5,500	4,960	5,500
Lamp Efficacy (lm/W)	N/A	111.2	123.5	127.2	137.5	196.1	212.0	226.7	245.1	250.0	250.0
System Wattage	N/A	71.5	68.0	78.0	80.0	50.6	51.9	43.8	44.9	39.7	44.0
System Lumens	N/A	7,473	8,064	9,523	10,560	9,523	10,560	9,523	10,560	9,523	10,560
System Efficacy (lm/W)	N/A	104.5	118.6	122.1	132.0	188.2	203.5	217.7	235.3	240.0	240.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	N/A	80	82	81	82	81	82	81	82	81	82
Correlated Color Temperature (CCT)	N/A	5,000	4,000	4,000	5,000	4,000	5,000	4,000	5,000	4,000	5,000
Average Lamp Life (thousand hours)	N/A	50	50	50	50	50	50	50	50	50	50
Annual Operating Hours (h/y)	N/A	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147
Lamp Price (2022$)	N/A	$89.59	$33.11	$37.22	$41.44	$32.35	$36.02	$31.71	$35.30	$31.11	$34.64
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	N/A	$19.00	$7.88	$7.50	$7.53	$6.52	$6.55	$6.39	$6.42	$6.27	$6.30
System (l/b/f) Cost (2022$/klm)[1]	N/A	$23.98	$8.21	$7.82	$7.85	$6.79	$6.82	$6.66	$6.69	$6.53	$6.56
Labor Cost (2022$/h)	N/A	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Labor Lamp Change (hours)	N/A	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total Installed Cost (2022$)	N/A	$200.80	$84.70	$92.92	$101.36	$83.18	$90.52	$81.90	$89.09	$80.70	$87.76
Annual Maintenance Cost (2022$)	N/A	$16.65	$7.02	$7.71	$8.41	$6.90	$7.51	$6.79	$7.39	$6.69	$7.28
Total Installed Cost (2022$/klm)	N/A	$50.51	$10.50	$9.76	$9.60	$8.73	$8.57	$8.60	$8.44	$8.47	$8.31
Annual Maintenance Cost (2022$/klm)	N/A	$4.19	$0.87	$0.81	$0.80	$0.72	$0.71	$0.71	$0.70	$0.70	$0.69

1. N/A because a fixture and an LED replacement lamp would not be purchased separately for a new installation or retrofit when there are integrated LED luminaires that are more efficient and cost effective. These lamps are sold only as replacements to go into existing fixtures.

Final

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Performance and Cost Characteristics » Commercial 8-ft Linear LED Luminaire Replacement for a 2-Lamp System

Higher efficacy compared with Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	N/A	73.0	90.0	78.0	72.0	49.7	45.9	42.4	41.6	37.9	41.6
System Lumens	N/A	8,000	8,200	9,465	10,400	9,465	10,400	9,465	10,400	9,465	10,400
System Efficacy (lm/W)	N/A	109.6	91.1	121.3	144.4	190.4	226.7	223.1	250.0	250.0	250.0
Ballast Efficiency (BLE)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	N/A	90	80	81	80	81	80	81	80	81	80
Correlated Color Temperature (CCT)	N/A	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Average Lifetime (thousand hours)	N/A	75	50	73	100	73	100	73	100	73	100
Annual Operating Hours (h/y)	N/A	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431
Lamp or Luminaire Price (2022$)	N/A	$759.16	$119.99	$142.48	$153.91	$109.90	$118.71	$96.00	$103.70	$82.68	$89.31
Ballast Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	N/A	$80.00	$14.63	$15.05	$14.80	$11.61	$11.41	$10.14	$9.97	$8.73	$8.59
Labor Cost (2022$/h)	N/A	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	N/A	1.0	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	N/A	$708.20	$206.52	$229.01	$240.44	$196.42	$205.24	$182.53	$190.23	$169.20	$175.83
Annual Maintenance Cost (2022$)	N/A	$39.16	$22.40	$17.46	$13.53	$14.40	$11.11	$13.09	$10.08	$11.84	$9.10
Total Installed Cost (2022$/klm)	N/A	$88.53	$25.18	$24.20	$23.12	$20.75	$19.73	$19.28	$18.29	$17.88	$16.91
Annual Maintenance Cost (2022$/klm)	N/A	$4.89	$2.73	$1.84	$1.30	$1.52	$1.07	$1.38	$0.97	$1.25	$0.87

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Performance and Cost Characteristics » Commercial Low-Bay Lighting Systems

The commercial low bay lighting characterized in this report is a one-lamp and one-ballast system in a low/high bay fixture that emits between 6,000 and 10,000 system lumens. Low bay lighting is defined as "interior lighting where the roof trusses or ceiling height is less than 25ft. above the floor" (IESNA, 2000). For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- Low bay conventional lighting technologies, such as metal halide and sodium vapor lamps, provide higher efficacy ranging from 80 lm/W to 100 lm/W. Older, mercury vapor lamps have much lower efficacy at approximately 40 lm/W.
- CCT and CRI values range broadly based on technology type for low bay products.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED luminaires, which are sold as one integrated system. Many factors influence the price of LED luminaires, including CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical luminaire prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial low-bay systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

ENERGY STAR:

- ENERGY STAR does not cover low/high bay luminaires (ENERGY STAR, 2012).

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Performance and Cost Characteristics » Commercial Low-Bay Lighting Systems

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime, and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

	Efficacy	Lifetime	Price	Potential for Improvements
Mercury Vapor	0%	0%	-0.5%	Limited because the technology is mature.
Metal Halide	0%	0%	-0.5%	Limited because the technology is mature.
Sodium Vapor	0%	0%	-0.5%	Limited because the technology is mature.

Final

U21806-MNSC-CE-0771-Att 4

Performance and Cost Characteristics » Commercial LED Low-Bay Luminaire

Higher efficacy compared with Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	68.1	84.0	40.0	73.0	76.0	47.1	49.0	40.5	48.0	40.0	48.0
System Lumens	4,877	10,000	5,000	10,000	12,000	10,000	12,000	10,000	12,000	10,000	12,000
System Efficacy (lm/W)	71.6	119.0	125.0	137.0	157.9	212.5	244.9	246.7	250.0	250.0	250.0
Ballast Efficiency	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	85	78	84	81	80	81	84	81	84	81	81
Correlated Color Temperature (CCT)	4,000	4,806	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	4,000
Average Lifetime (thousand hours)	50	74	75	65	60	65	60	65	60	65	60
Annual Operating Hours (h/y)	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042
Lamp or Luminaire Price (2022$)	$903.82	$281.00	$63.99	$145.46	$285.89	$123.82	$243.37	$111.24	$218.63	$99.09	$194.75
Ballast Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$185.31	$28.10	$12.80	$14.55	$23.82	$12.38	$20.28	$11.12	$18.22	$9.91	$16.23
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$865.44	$396.83	$162.99	$244.46	$384.89	$222.82	$342.37	$210.24	$317.63	$198.09	$293.75
Annual Maintenance Cost (2022$)	$69.95	$37.02	$12.23	$24.24	$45.18	$21.55	$39.45	$19.99	$36.12	$18.48	$32.90
Total Installed Cost (2022$/klm)	$177.44	$39.68	$32.60	$24.45	$32.07	$22.28	$28.53	$21.02	$26.47	$19.81	$24.48
Annual Maintenance Cost (2022$/klm)	$14.34	$3.70	$2.45	$2.42	$3.77	$2.16	$3.29	$2.00	$3.01	$1.85	$2.74

1. N/A because the lamp and fixture are both included in the luminaire.

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Performance and Cost Characteristics » Commercial High-Bay Lighting Systems

Final

The commercial high-bay lighting characterized in this report is a one-lamp and one-ballast system in a low/high bay fixture that emits greater than 10,000 system lumens. High-bay lighting is defined as "interior lighting where the roof trusses or ceiling height is greater than 25ft. above the floor" (IESNA, 2000). For all lamp technologies, an annual fixture renovation rate of 10% (i.e., 10-year fixture service life) is used to reflect the proportion of equipment that retires each year.

Performance:

- High bay conventional lighting technologies, such as metal halide and sodium vapor lamps, provide higher efficacy ranging from 80 lm/W to 100 lm/W. Older, mercury vapor lamps have much lower efficacy at approximately 40 lm/W.
- CCT and CRI values range broadly based on technology type for high bay products.

Cost:

- The total installed cost is the price of a lamp, ballast (if applicable), and fixture plus the cost for labor associated with the installation, except for in the case of LED luminaires, which are sold as one integrated system. Many factors influence the price of LED luminaires including, CRI, lifetime, dimming capabilities, and efficacy. Therefore, typical luminaire prices in 2022 reflecting a mix of lamp characteristics and features were used as the basis for projections for both typical and high efficacy products in the future.
- Annual maintenance costs are the cost of labor for replacing the lamps and the cost of the replacement lamp itself. The frequency at which lamps are replaced is a function of lamp life and the annual operating hours for commercial high bay systems (DOE SSL Program, 2012a).
- Commercial lighting disposal costs are estimated to be $0.12 per linear foot of fluorescent lamps, $1.50 per lamp for HID lamps, and $0.50 for CFLs (EPA, 2022).

ENERGY STAR:

- ENERGY STAR does not cover low/high bay luminaires (ENERGY STAR, 2012).

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Performance and Cost Characteristics » Commercial High-Bay Lighting Systems

Final

Future Performance Improvements:

- Projections were provided for both typical and high performing products for 2030, 2040, and 2050. We assume manufacturers will focus would be on improving efficacy, lifetime and price for products at constant CRI and CCT values.
- Due to continued R&D investment, competition from LED lighting products, and general market demand for cost-effective lighting, the performance and cost characteristics of conventional lighting technologies are expected to improve over the analysis period. However, the ability of these conventional technologies to react rapidly (in terms of performance improvement) to the emergence of a new light source such as LED lighting is relatively small because these are mature technologies (particularly incandescent and fluorescent) and established market competitors (Navigant, 2019).
- For LED technology, efficacy, lifetime, and price improvements were based on the model described in the Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019). For traditional technologies, the following future improvements were assumed to occur year over year through 2050.

	Efficacy	Lifetime	Price	Potential for Improvements
Mercury Vapor	0%	0%	-0.5%	Limited because the technology is mature.
Metal Halide	0%	0%	-0.5%	Limited because the technology is mature.
Sodium Vapor	0%	0%	-0.5%	Limited because the technology is mature.

Final

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Performance and Cost Characteristics » Commercial LED High-Bay Luminaire

Higher efficacy compared with Reference Case

DATA	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Lumens[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Efficacy (lm/W) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System Wattage	212	167	150	138	130	89	84	76	76	74	76
System Lumens	18,915	18,797	18,500	18,500	18,900	18,500	18,900	18,500	18,900	18,500	18,900
System Efficacy (lm/W)	89	113	123	134	145	208	225	242	250	250	250
Ballast Efficiency	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CRI	74	78	80	80	80	80	80	80	80	80	80
Correlated Color Temperature (CCT)	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Average Lifetime (thousand hours)	70	67	100	100	100	100	100	100	100	100	100
Annual Operating Hours (h/y)	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042	4,042
Lamp or Luminaire Price (2022$)	$2,842.05	$448.43	$177.54	$195.81	$234.20	$162.12	$193.90	$148.87	$178.06	$136.20	$162.90
Ballast Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Fixture Price (2022$) [1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lamp Cost (2022$/klm)[1]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
System (l/b/f) Cost (2022$/klm)	$150.25	$23.86	$9.60	$10.58	$12.39	$8.76	$10.26	$8.05	$9.42	$7.36	$8.62
Labor Cost (2022$/h)	$77.22	$77.22	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00	$66.00
Labor System Installation (hours)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Labor Lamp Change (hours)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Installed Cost (2022$)	$2,957.88	$564.26	$276.54	$294.81	$333.20	$261.12	$292.90	$247.87	$277.06	$235.20	$261.90
Annual Maintenance Cost (2022$)	$170.78	$34.07	$11.18	$11.91	$13.47	$10.55	$11.84	$10.02	$11.20	$9.51	$10.58
Total Installed Cost (2022$/klm)	$156.38	$30.02	$14.95	$15.94	$17.63	$14.11	$15.50	$13.40	$14.66	$12.71	$13.86
Annual Maintenance Cost (2022$/klm)	$9.03	$1.81	$0.60	$0.64	$0.71	$0.57	$0.63	$0.54	$0.59	$0.51	$0.56

1. N/A because the lamp and fixture are both included in the luminaire.

Refrigeration

U21806-MNSC-CE-0771-Att 4

Performance and Cost Characteristics » Commercial Compressor Rack Systems

Final

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)[1]	1,200	1,200	1,200	1,190	930	N/A	1,190	930	1,190	930	1,190	930
Median Store Size (ft^2)	46,500	31,997	35,197	35,197	35,197	N/A	35,197	35,197	35,197	35,197	35,197	35,197
Power Input (kW)	162	155	162	160	125	N/A	160	125	160	125	160	125
Annual Energy Use (MMWh/y)[2]	1,497	1,497	1,305	1,232	1,160	N/A	1,109	1,044	998	939	898	845
Indexed Annual Efficiency[3]	1.00	1.00	1.15	1.21	1.29	N/A	1.35	1.43	1.50	1.59	1.67	1.77
Average Life (years)	15	15	15	15	15	N/A	15	15	15	15	15	15
Total Installed Cost (2022$)	$630,000	$630,000	$488,000	$625,000	$630,000	N/A	$625,000	$630,000	$625,000	$630,000	$625,000	$630,000
Total Installed Cost (2022$/kBtu/h)	$525,000	$525,000	$406,667	$525,210	$677,419	N/A	$525,210	$677,419	$525,210	$677,419	$525,210	$677,419
Annual Maintenance Cost (2022$)[4]	$3,400	$3,400	$3,400	$3,400	$3,400	N/A	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400
Annual Maintenance Cost (2022$/kBtu/h)	$2,833	$2,833	$2,833	$2,857	$3,656	N/A	$2,857	$3,656	$2,857	$3,656	$2,857	$3,656

1. The total capacity represents the nominal compressor capacity required for the entire refrigeration system of a typical supermarket. This refrigeration system usually includes two low temperature racks and two medium temperature racks. For 2018, a 1,200 MBtu/h total cooling capacity is based on a 200-ton estimate for total capacity–80 tons for the medium temperature racks and 20 tons for the low temperature racks.
2. Capacity and annual energy consumption for 2022 and beyond are based on market research and Guidehouse estimates.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Maintenance cost includes oil changes, bearing lubrication, filter replacement, and system functionality checks-approximately half a day per rack of labor for technician is assumed.

- Commercial compressor rack systems that serve commercial supermarket display cases and walk-ins consist of a number of parallel-connected compressors located in a separate machine room. By modulating compressor capacity, these integrated systems provide higher efficiency and mechanical longevity.
- Rack integrators generally supply a packaged compressor rack for which much of the necessary piping, insulation, components, and controls are pre-assembled.
- A typical supermarket will have 10 to 20 compressors mounted in racks in the 3-horsepower (hp) to 15-hp size range. Usually, each rack has three to five compressors serve a series of loads with nearly identical evaporator temperature.
- The duty cycle for compressors is usually in the range of 60% to 70%.
- Energy use and capacity for the Reference Case are projected to remain static over the coming decades because commercial compressor racks systems are a mature technology. The Reference Case assumes low R&D efforts because it is an established technology.
- **For this Advanced Case, a 10% reduction in energy consumption is assumed to occur over the Reference Case for 2022 and beyond due to vacuum insulated panel (VIP) adoption by display cases and a relaxation in charge size limits for more efficient, low global warming potential (GWP) refrigerants. Also, increased adoption of toxic/flammable refrigerants such as ammonia and propane due to improved safety technology such as leak detection**.

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Performance and Cost Characteristics » Commercial Condensers

Final

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)[1]	1,680	1,520	1,440	1,440	1,440	N/A	1,440	1,368	1,300	1,300	1,235	1,235
Median Store Size (ft^2)	46,500	31,997	35,197	35,197	35,197	N/A	35,197	35,197	35,197	35,197	35,197	35,197
Power Input (kW)	25	25	18	18	18	N/A	18	18	18	18	18	18
Annual Energy Use (MMWh/y)	120	120	115	106	86	N/A	95	77	86	70	77	63
Indexed Annual Efficiency[2]	1.00	1.00	1.04	1.13	1.40	N/A	1.26	1.55	1.40	1.72	1.55	1.91
Average Life (years)	10	10	10	10	10	N/A	10	10	10	10	10	10
Total Installed Cost (2022$)	$54,000	$60,000	$54,000	$60,000	$80,000	N/A	$60,000	$80,000	$60,000	$80,000	$60,000	$80,000
Total Installed Cost (2022$/kBtu/h)	$32,143	$39,474	$37,500	$41,667	$55,556	N/A	$41,667	$58,480	$46,168	$61,538	$48,598	$64,777
Annual Maintenance Cost (2022$)[3]	$954	$954	$954	$954	$954	N/A	$954	$954	$954	$954	$954	$954
Annual Maintenance Cost (2022$/kBtu/h)	$0.57	$0.63	$0.66	$0.66	$0.66	N/A	$0.66	$0.70	$0.73	$0.73	$0.77	$0.77

1. Total capacity is the total heat rejected (THR) by condensers comprised of two low temperature condensers (THRL = 240 MBtu/h each, suction temperature = -25°F, condensing temperature-110°F) and two medium temperature condensers (THRM = 520 MBtu/h each, suction temperature = 15°F, condensing temperature = 115°F); ambient temperature = 95°F. (NCI, 2009). For 2022 and beyond, capacity was estimated by Guidehouse.
2. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
3. Maintenance cost includes coil cleaning, leak checking, belt replacement as necessary, and system functionality checks.

- Condensers are designed with multiple methods of cooling: air-cooled, water-cooled, and evaporative. These units can be single-circuit or a multiple circuit.
- Commercial condensers are remotely located, typically installed on the roof of a supermarket.
- For use with parallel compressors in supermarkets, air-cooled units are the most commonly used condensers. This analysis is based on multiple air-cooled condensers connected to a supermarket refrigeration system comprised of two low temperature condensers and two medium temperature condensers.
- Each compressor rack has a dedicated condenser or a separate circuit of a single common condenser. Condenser temperatures of multiple racks are often different.
- The duty cycle for condensers is usually in the range 50%-70%.
- **For this Advanced Case, a 10% reduction in energy consumption and a 5% reduction in required capacity is assumed to occur over the Reference Case for 2020 and beyond due to VIP adoption by display cases and a relaxation in charge size limits for more efficient, low GWP. Also, increased adoption of toxic/flammable refrigerants such as ammonia and propane due to improved safety technology such as leak detection**.

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Performance and Cost Characteristics » Commercial Supermarket Display Cases

Final

Lower annual energy use, increased installed cost compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	17,623	11,850	11,850	11,850	11,850	N/A	11,850	11,850	11,850	11,850	11,850	11,850
Median Store Size (ft^2)	46,500	31,997	35,197	35,197	35,197	N/A	35,197	35,197	35,197	35,197	35,197	35,197
Case Length (ft)	12	12	12	12	12	N/A	12	12	12	12	12	12
Annual Energy Use (kWh/y)[1,2]	13,497	10,506	10,506	9,771	9,087	N/A	9,282	8,632	8,818	8,201	8,377	7,791
Annual Energy Use / Case Length (kWh/ft)	1,125	876	876	814	757	N/A	774	719	735	683	698	649
Indexed Annual Efficiency[3]	1.00	1.28	1.28	1.38	1.49	N/A	1.45	1.56	1.53	1.65	1.61	1.73
Average Life (years)	10	10	10	10	10	N/A	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$8,510	$10,650	$7,265	$9,500	$10,680	N/A	$9,500	$10,680	$9,500	$10,680	$9,500	$10,680
Total Installed Cost (2022$)	$10,811	$12,650	$9,265	$11,500	$12,680	N/A	$11,500	$12,680	$11,500	$12,680	$11,500	$12,680
Total Installed Cost (2022$/kBtu/h)	613	1,068	782	970	1,070	N/A	970	1,070	970	1,070	970	1,070
Annual Maintenance Cost (2022$)[4]	$940	$940	$940	$940	$940	N/A	$940	$940	$940	$940	$940	$940
Annual Maintenance Cost (2022$/kBtu/h)	$53.34	$79.32	$79.32	$79.32	$79.32	N/A	$79.32	$79.32	$79.32	$79.32	$79.32	$79.32

1. For 2022 and beyond, energy consumption and cost values were estimated using shipment-weighted averages reported in DOE's 2014 CRE Final Rule Technical Support Document (TSD) for equipment commonly used as display cases. DOE's updated conservation standard went into effect in 2017, so units sold in 2018 are assumed to comply with this standard.
2. For consistency with DOE rulemaking practices, Supermarket Display Case Energy Use reported above includes energy use of the compressor racks and condensers. To avoid double counting, do not add Energy Use from the Compressor Rack or Condenser Systems tabs if calculating total energy consumption.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Maintenance cost includes preventative maintenance costs such as cleaning evaporator coils, drain pans, fans, and intake screens as well as lamp replacements and other lighting maintenance activities. After 2012, these values are based on a reported maintenance and repair cost of $220 per unit for preventative maintenance plus approximately $60 per linear foot for additional repair and maintenance.

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Performance and Cost Characteristics » Commercial Supermarket Display Cases

Final

- DOE set federal energy efficiency standards for Commercial Refrigeration Equipment (CRE) in 2009. These standards set maximum daily energy consumption levels, in kilowatt-hours per day, for display cases manufactured sold in the United States on or after January 1, 2012.
- DOE updated its Energy Conservation Standards for Commercial Refrigeration Equipment in 2014 for equipment sold on or after March 27, 2017.
- The table below lists equipment used as supermarket display cases and their corresponding Energy Conservation Standard levels. The maximum allowable daily energy consumption for each equipment class is a linear function of Total Display Area (TDA).

Equipment Description	Standards Equation (2012)	Standards Equation (2017)
Vertical Open Cooler (VOP.RC.M)	0.82xTDA+4.07	0.64xTDA+4.07
Semi-Vertical Open Cooler (SVO.RC.M)	0.83xTDA+3.18	0.66xTDA+3.18
Horizontal Open Cooler (HZO.RC.M)	0.35xTDA+2.88	0.35xTDA+2.88
Transparent-Doored Cooler (VCT.RC.M)	0.22xTDA+1.95	0.15xTDA+1.95
Deli Display Cooler (SOC.RC.M)	0.51xTDA+0.11	0.44xTDA+0.11
Transparent-Doored Freezer (VCT.RC.L)	0.56xTDA+2.61	0.49xTDA+2.61
Horizontal Open Freezer (HZO.RC.L)	0.57xTDA+6.88	0.55xTDA+6.88

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Performance and Cost Characteristics » Commercial Supermarket Display Cases

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- According to CBECS 2018 microdata, the average building size for food sale building type is 31,997.
- Unit energy consumption for 2022 and beyond is estimated using a shipment-weighted average by efficiency level and equipment class, using data in DOE's 2014 CRE Final Rule TSD with updated analysis from Guidehouse in 2016. The equipment classes analyzed are listed in the table on the previous slide.
- Supermarket refrigeration systems consist of refrigerated display cases, condensing units, and centralized compressor racks.
- A typical supermarket display case contains lighting, evaporators, evaporator fans, piping, insulation, valves, and controls.
- The efficiency of supermarket display cases can be increased through the use of improved evaporator coils, larger evaporators, higher efficiency evaporator fan blades, high efficiency doors, LED lighting, and improved insulation.
- **For 2020 and beyond, accelerated adoption of energy savings technologies is assumed to take place more than in the Reference Case, including accelerated shipments migration to doored over open units, where applicable, as well as vacuum insulated panels.**
- **The incremental cost of VIPs is assumed to decrease from its present value due to increased R&D funding.**
- **Projected installed costs for this Advanced Case are higher than the Reference Case, even assuming increased R&D funding. Advanced energy-saving technologies are assumed to be made financially viable for operators by increased market incentives such as utility efficiency rebate programs and/or carbon pricing.**
- **This Advanced Case assumes a transition from Hydrofluorocarbons (HFC) to more efficient propane and ammonia refrigerants by 2040.**
- **Advanced Case assumes a 5% reduction in energy use per decade based on technology and efficiency improvements.**

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Performance and Cost Characteristics » Commercial Reach-In Refrigerators

Final

Lower annual energy use, increased installed cost compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	2,929	2,400	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349
Size (ft^3)	49	49	46	46	46	47	46	46	46	46	46	46
Annual Energy Use (kWh/y)	2,340	2,222	1,935	1,351	810	810	1,283	770	1,283	770	1,283	770
Annual Energy Use / Volume (kWh/y/ft^3)[1]	48	45	42	29	18	17	28	17	28	17	28	17
Indexed Annual Efficiency[3]	1.00	1.05	1.21	1.73	2.89	2.89	1.82	3.04	1.82	3.04	1.82	3.04
Average Life (years)	10	10	10	10	10	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$2,624	$2,403	$2,728	$2,780	$3,021	$3,021	$3,058	$3,323	$3,323	$3,364	$3,655	$3,655
Total Installed Cost (2022$)[4]	$3,454	$3,282	$3,591	$3,643	$3,884	$3,884	$3,932	$4,197	$4,197	$4,238	$4,529	$4,529
Total Installed Cost (2022$/kBtu/h)	$1,179	$1,368	$1,529	$1,551	$1,654	$1,654	$1,885	$2,568	$1,885	$2,568	$1,885	$2,568
Annual Maintenance Cost (2022$)[5]	$185	$185	$185	$185	$185	$185	$185	$185	$185	$185	$185	$185
Annual Maintenance Cost (2022$/kBtu/h)	$63	$77	$79	$79	$79	$79	$79	$79	$79	$79	$79	$79

1. EPACT 2005 energy standards went into effect in 2010. 2022 low efficiency cost and energy consumption values are based on minimum compliance with this standard. Unless otherwise noted, all other cases are based on shipment-weighted averages solid- and transparent-doored units reported in the 2014 CRE TSD. DOE's updated Energy Conservation standards went into effect in 2017; therefore, compliance with this standard is assumed for 2022 and beyond.
2. The ENERGY STAR category is based on a shipment weighted average of solid- and transparent-doored units that are minimally compliant with ENERGY STAR v3, effective October 1, 2014. Units compliant with ENERGY STAR are found to be the most efficient reach-in refrigeration equipment on the market in 2022.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use)/(Energy Use).
4. Installation cost for 2012 is based on NCI 2009 report that assumes a cost of $863. Installation cost for 2022 and beyond is based DOE's 2014 CRE Final Rule and additional analysis by Guidehouse, which assumes an installation cost of $878 for self-contained equipment.
5. Maintenance costs after 2012 are based on DOE's CRE 2014 Final Rule TSD, which reports $35 annual preventative maintenance, per unit, per year, plus approximately $40 per linear foot, per year of additional repair and maintenance costs for the units characterized.

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Performance and Cost Characteristics » Commercial Reach-In Refrigerators

Final

- The Energy Policy Act of 2005 (EPACT 2005) set maximum daily energy consumption levels, in kilowatt-hours per day, for commercial reach-in refrigerators that went into effect on January 1, 2010. The daily energy consumption is based on the volume of the unit (V) in ft^3.
- In 2014, DOE updated its energy conservation standards for reach-in refrigerators, effective March 27, 2017. Both standards are reported in the table below.

Equipment Class	EPCA Standard Level (2010)	DOE Standard Level (2017)
Solid Door (VCS.SC.M)	0.10xV+2.04	0.05xV + 1.36
Glass Door (VCT.SC.M)	0.12xV+3.34	0.1xV+0.86

- In 2013, EPA updated its ENERGY STAR specifications for reach-in refrigerators, effective March 27, 2017. These standards are also based on the refrigerated volume of the unit.

Reach-In Refrigerator Size	0 < V < 15	15 ≤ V < 30	30 ≤ V < 50	50 ≤ V
Solid Door (VCS.SC.M)	0.022xV+0.97	0.066xV+0.31	0.04xV+1.09	0.024xV+1.89
Glass Door (VCT.SC.M)	0.095xV+0.445	0.05xV+1.12	0.076xV+0.034	0.105xV-1.111

- Unit energy consumption for 2012 and beyond was estimated based on shipment-weighted averages by efficiency level and equipment class for 49 ft^3 VCS.SC.M and VCT.SC.M units reported in DOE's 2014 CRE Final Rule TSD with updated analysis from Guidehouse in 2016. These units were estimated to comprise approximately 85% and 15% of total reach-in refrigerator shipments, respectively.
- The efficiency of commercial reach-in refrigerators can be increased through the use of efficient compressors, efficient evaporator fans, efficient condenser fans, electric defrost, and more efficient lighting.
- After 2022, the high efficiency cases are based on solid-doored units rather than shipment-weighted averages due to the assumption that stakeholders will increasingly value energy conservation.
- **Unit energy consumption is expected to decrease as a result of DOE's updated energy conservation standards, as well as a transition to more efficient propane refrigerant due to compliance with EPA Significant New Alternatives Policy (SNAP).**
- **For this Advanced Case, the typical unit in 2020 is assumed to comply with DOE's updated energy conservation standards for commercial refrigeration.**
- **A shipments migration from transparent- to solid-doored units is assumed for the Advanced Case.**
- **By 2040, the adoption of vacuum insulated panels is assumed to occur, with the aid of decreased incremental costs due to increased R&D funding.**
- **Projected installed costs for this Advanced Case are higher than the Reference Case, even assuming increased R&D funding. Advanced energy-saving technologies are assumed to be made financially viable for operators by increased market incentives such as utility efficiency rebate programs and/or carbon pricing.**
- **This analysis finds that with increased R&D and market incentives for energy-efficient technologies, a limit of possible efficiency improvements for self-contained, vapor compression refrigeration systems will be reached by 2040.**

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Performance and Cost Characteristics » Commercial Reach-In Freezers

Final

Lower annual energy use, increased installed cost compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	4,341	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340	4,340
Size (ft^3)	49	49	49	49	49	49	49	49	49	49	49	49
Annual Energy Use (kWh/y)[1]	6,023	5,585	5,585	4,847	4,110	4,110	4,362	3,699	3,926	3,329	3,533	2,996
Annual Energy Use / Volume ($kWh/y/ft^3$)	123	114	114	99	84	84	89	75	80	68	72	61
Indexed Annual Efficiency[3]	1.00	1.08	1.08	1.24	1.47	1.47	1.38	1.63	1.53	1.81	1.70	2.01
Average Life (years)	10	10	10	10	10	10	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$2,886	$2,886	$2,886	$3,175	$3,493	$3,493	$3,493	$3,842	$3,842	$4,226	$4,226	$4,649
Total Installed Cost (2022$)[4]	$3,749	$3,749	$3,749	$4,125	$4,443	$4,443	$4,443	$4,792	$4,792	$5,176	$5,176	$5,599
Total Installed Cost (2022$/kBtu/h)	$864	$864	$864	$950	$1,024	$1,024	$1,024	$1,104	$1,104	$1,193	$1,193	$1,290
Annual Maintenance Cost (2022$)[5]	$181	$181	$181	$181	$181	$181	$181	$181	$181	$181	$181	$181
Annual Maintenance Cost (2022$/kBtu/h)	$41.70	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71	$41.71

1. A 49 ft^3 unit was characterized, because it was the representative size selected for DOE's rulemaking analysis.
2. The ENERGY STAR category was based on a solid-doored unit that is minimally compliant with ENERGY STAR v3, effective October 1, 2014.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 and 2018 is based on DOE's on-going CRE rulemaking, which assumes a cost of $863 for self-contained equipment and $950 for 2022 and beyond based on analysis from Guidehouse.
5. Maintenance costs are calculated based on a $35 per unit annual preventative maintenance cost, plus an additional $45 per linear foot repair and maintenance cost estimated based on values reported in the CRE TSD.

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Performance and Cost Characteristics » Commercial Reach-In Freezers

Final

- EPACT 2005 set maximum daily energy consumption levels, in kilowatt-hours per day, for commercial reach-in freezers that went into effect on January 1, 2010. The daily energy consumption is based on the volume of the unit (V) in ft^3.
- In March of 2017, DOE updated its energy conservation standards for commercial refrigeration equipment, including reach-in freezers. Both the EPCA and DOE standards are reported in the table below.

Equipment Class	EPCA (2010)	DOE Standard Level (2017)
Solid Door (VCS.SC.L)	0.4xV+1.38	0.22xV+1.38
Transparent Door (VCT.SC.L)	0.75xV+4.10	0.29xV+2.95

- In 2013, EPA updated its ENERGY STAR specifications for reach-in freezers, effective March 27, 2017. These standards are also based on the refrigerated volume of the unit.

Reach-In Freezer Size	0 < V < 15	15 ≤ V < 30	30 ≤ V < 50	50 ≤ V
Solid Door (VCS.SC.L)	0.21xV+0.9	0.12xV+2.248	0.285xV-2.703	0.142xV+4.445
Glass Door (VCT.SC.L)	0.232xV+2.36	0.232xV+2.36	0.232xV+2.36	0.232xV+2.36

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Performance and Cost Characteristics » Commercial Reach-In Freezers

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- The commercial reach-in freezer characterized in this report, which is the typical unit according to DOE's 2014 CRE rulemaking, is a 49 cubic ft. solid two-door unit with a nominal compressor size of 4,341 Btu/h.
- The efficiency of commercial reach-in freezers can be increased through the use of efficient compressors, efficient evaporator fans, efficient condenser fans, electric defrost, and more efficient lighting.
- **Unit energy consumption for reach-in freezers is expected to decrease as a result of DOE's updated energy conservation standards, as well as a transition to more efficient propane refrigerant due to EPA SNAP compliance.**
- **The typical unit in 2020 is assumed to comply with DOE's updated energy conservation standards for commercial refrigeration.**
- **By 2040, the adoption of vacuum insulated panels is assumed to occur, with the aid of decreased incremental costs due to increased R&D funding.**
- **Projected installed costs for this Advanced Case are higher than the Reference Case, even assuming increased R&D funding. Advanced energy-saving technologies are assumed to be made financially viable for operators by increased market incentives such as utility efficiency rebate programs.**
- **This analysis finds that with increased R&D and market incentives for energy-efficient technologies, a limit of possible efficiency improvements for self-contained, vapor compression refrigeration systems will be reached by 2040.**

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Performance and Cost Characteristics » Commercial Walk-In Refrigerators

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/hr)[1]	37,820	39,422	41,024	41,024	41,024	N/A	41,024	41,024	41,024	41,024	41,024	41,024
Size (ft^2)	305	240	240	240	240	N/A	240	240	240	240	240	240
Annual Energy Use (kWh/yr)[2]	30,689	20,040	17,600	16,200	14,800	N/A	14,580	13,320	13,122	11,988	11,810	10,789
Annual Energy Use / Area ($kWh/ft^2/yr$)	101	84	73	68	62	N/A	61	56	55	50	49	45
Indexed Annual Efficiency[3]	1.00	1.53	1.74	1.89	2.07	N/A	2.10	2.30	2.34	2.56	2.60	2.84
Insulated Box Average Life (yrs)	12	12	12	12	12	N/A	12	12	12	12	12	12
Compressor Average Life (yrs)	10	10	10	10	10	N/A	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$23,598	$19,847	$16,050	$19,847	$23,644	N/A	$16,050	$23,644	$16,050	$23,644	$16,050	$23,644
Total Installed Cost (2022$)[4]	$27,012	$23,897	$20,100	$23,897	$27,694	N/A	$20,100	$27,694	$20,100	$27,694	$20,100	$27,694
Total Installed Cost (2022$/kBtu/hr)	$714	$606	$490	$583	$675	N/A	$490	$675	$490	$675	$490	$675
Annual Maintenance Cost (2022$)[5]	$716	$740	$740	$740	$740	N/A	$740	$740	$740	$740	$740	$740
Annual Maintenance Cost (2022$/kBtu/hr)	$18.93	$18.77	$18.04	$18.04	$18.04	N/A	$18.04	$18.04	$18.04	$18.04	$18.04	$18.04

1. Assumes medium temperature units are refrigerators.
2. Average unit energy consumption was adapted from the DOE CRE 2016 report by assuming electronically commutated motor (ECM) evaporator fan motors are required for Energy Policy & Conservation Act (EPCA) compliance, as well as ECM condenser fan motors.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 and beyond is based on DOE's Walk-In Technical Support Document (TSD).
5. Maintenance cost includes checking and maintaining refrigerant charge levels, checking settings, and cleaning heat exchanger coils.

- For 2012 and beyond, the unit characterized was a walk-in storage cooler, based on DOE's WICF TSD.
- A typical walk-in refrigerator includes:
  - insulated floor and wall panels
  - merchandising doors, shelving, and lighting (not included in cost estimate)
  - semi-hermetic reciprocating compressor
  - refrigerant (R404A)
  - condenser
  - evaporator
- Energy consumption is assumed to scale with the AWEF (Annual Walk-in Energy Factor), defined as the ratio of total heat removed from the refrigerated volume per year to the total electrical energy input of refrigeration systems over the same time period.
- The installation cost consists of freight and delivery costs in addition to on-site assembly.
- **This Advanced Case assumes a projected 10% decrease in energy consumption over the Reference Case due to adoption of more efficient refrigerants.**

The Energy Independence and Security Act (EISA) of 2007 included prescriptive standards for walk-in refrigerators (coolers) that went into effect in 2009. These prescriptive standards, which are included in the analysis for all units for 2012 and beyond, state that all walk-in refrigerators manufactured after January 1, 2009, must:

- For 2012 and beyond
- have automatic door closers
- have strip doors, spring hinged doors, or other method of minimizing infiltration when doors are open
- contain wall, ceiling, and door insulation of at least R–25, except for glazed portions of doors and structural members
- use electronically commutated motors or three-phase motors (for evaporator fan motors of under 1 horsepower and less than 460 volts)
- use electronically commutated motors, permanent split capacitor-type motors, or three-phase motors (for condenser fan motors of under 1 horsepower)
- use light sources with an efficacy of 40 lumens per watt or more, including ballast losses (if any), except that light sources with an efficacy of 40 lumens per watt or less, including ballast losses (if any), may be used in conjunction with a timer or device that turns off the lights within 15 minutes of when the walk-in refrigerator is not occupied by people.

In 2014, DOE updated its energy conservation standards for walk-in coolers and freezers. Minimum AWEF (Annual Walk-In Energy Factor) was set for refrigeration systems, as well as upper limits on energy consumption attributable to passage, freight, and display doors. DOE elected not to set new standards for the R-value of Walk-In Panels.

ENERGY CONSERVATION STANDARDS FOR WALK-IN COOLERS AND WALK-IN FREEZERS

Class descriptor	Class	Standard level
Refrigeration Systems Minimum AWEF (Btu/W-h)		
Dedicated Condensing, Medium Temperature, Indoor System, <9,000 Btu/h Capacity	DC.M.I, <9,000	5.61
Dedicated Condensing, Medium Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.M.I, ≥9,000	5.61
Dedicated Condensing, Medium Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.M.O, <9,000	7.60
Dedicated Condensing, Medium Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.M.O, ≥9,000	7.60
Dedicated Condensing, Low Temperature, Indoor System, <9,000 Btu/h Capacity	DC.L.I, <9,000	$5.93 \cdot 10^{\%5} \cdot Q + 2.33$
Dedicated Condensing, Low Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.L.I, ≥9,000	3.10
Dedicated Condensing, Low Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.L.O, <9,000	$2.30 \cdot 10^{\%4} \cdot Q + 2.73$
Dedicated Condensing, Low Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.L.O, ≥9,000	4.79
Multiplex Condensing, Medium Temperature	MC.M	10.89
Multiplex Condensing, Low Temperature	MC.L	6.57
Panels Minimum R-value (h-ft2-°F/Btu)		
Structural Panel, Medium Temperature	SP.M	25
Structural Panel, Low Temperature	SP.L	32
Floor Panel, Low Temperature	FP.L	28
Non-Display Doors Maximum energy consumption (kWh/day) **		
Passage Door, Medium Temperature	PD.M	$0.05 \cdot A_{nd} + 1.7$
Passage Door, Low Temperature	PD.L	$0.14 \cdot A_{nd} + 4.8$
Freight Door, Medium Temperature	FD.M	$0.04 \cdot A_{nd} + 1.9$
Freight Door, Low Temperature	FD.L	$0.12 \cdot A_{nd} + 5.6$
Display Doors Maximum Energy Consumption (kWh/day) †		
Display Door, Medium Temperature	DD.M	$0.04 \cdot A_{dd} + 0.41$
Display Door, Low Temperature	DD.L	$0.15 \cdot A_{dd} + 0.29$

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Performance and Cost Characteristics » Commercial Walk-In Freezers

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	22,114	23,500	23,500	23,500	23,500	N/A	23,500	23,500	23,500	23,500	23,500	23,500
Size (ft^2) [1]	172	161	161	161	161	N/A	161	161	161	161	161	161
Annual Energy Use (kWh/y)[2]	22,862	17,600	21,400	21,400	21,400	N/A	19,260	19,260	17,334	17,334	15,601	15,601
Annual Energy Use / Area ($kWh/ft^2/y$)	133	109	133	133	133	N/A	120	120	108	108	97	97
Indexed Annual Efficiency[3]	1.00	1.30	1.07	1.07	1.07	N/A	1.19	1.19	1.32	1.32	1.47	1.47
Insulated Box Average Life (years)	12	12	12	12	12	N/A	12	12	12	12	12	12
Compressor Average Life (years)	10	10	10	10	10	N/A	10	10	10	10	10	10
Retail Equipment Cost (2022$)	$22,008	$21,950	$21,950	$22,850	$23,750	N/A	$22,850	$23,750	$22,850	$23,750	$22,850	$23,750
Total Installed Cost (2022$)[4]	$24,058	$23,950	$23,950	$24,850	$25,750	N/A	$24,850	$25,750	$24,850	$25,750	$24,850	$25,750
Total Installed Cost (2022$/kBtu/h)	$1,088	$1,019	$1,019	$1,057	$1,096	N/A	$1,057	$1,096	$1,057	$1,096	$1,057	$1,096
Annual Maintenance Cost (2022$)[5]	$741	$741	$741	$740	$741	N/A	$740	$741	$740	$741	$740	$741
Annual Maintenance Cost (2022$/kBtu/h)	$33.51	$31.53	$31.53	$31.49	$31.53	N/A	$31.49	$31.53	$31.49	$31.53	$31.49	$31.53

1. Based on DOE's 2014 WICF Final Rule TSD and additional analysis by Guidehouse, the average floor area for a walk-in storage freezer as 161 ft^2.
2. EISA 2007 includes prescriptive standards for walk-in freezers that went into effect in 2009. All units for 2012 and beyond include these prescriptive standards. Units for 2022 and beyond are characterized using data from DOE's 2014 WICF rulemaking. All units for 2022 and beyond are assumed to comply with this standard.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Installation cost for 2012 and beyond is based on DOE's WICF TSD and additional analysis by Guidehouse.
5. Maintenance cost includes checking and maintaining refrigerant charge levels, checking settings, and cleaning heat exchanger coils.

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Performance and Cost Characteristics » Commercial Walk-In Freezers

- The commercial walk-in freezer characterized in this report is a walk-in storage freezer with an area of 161 ft^2.
- A typical walk-in freezer includes:
  - insulated floor, door, and wall panels
  - semi-hermetic reciprocating compressor
  - refrigerant (R404A)
  - condenser
  - evaporator
- Energy consumption is assumed to scale with the AWEF (Annual Walk-in Energy Factor), defined as the ratio of total heat removed from the refrigerated volume per year to the total electrical energy input of refrigeration systems over the same time period.
- The installation cost consists of freight and delivery costs in addition to on-site assembly.
- **This Advanced Case assumes a projected 10% decrease in energy consumption over the Reference Case due to adoption of more efficient refrigerants.**

EISA 2007 included prescriptive standards for walk-in freezers that went into effect in 2009. These prescriptive standards, which are included in all units for 2011 and beyond, state that all walk-in freezers manufactured after January 1, 2009, must:

- have automatic door closers
- have strip doors, spring hinged doors, or other method of minimizing infiltration when doors are open
- contain wall, ceiling, and door insulation of at least R–32, except for glazed portions of doors and structural members
- contain floor insulation of at least R–28
- use electronically commutated motors or three-phase motors (for evaporator fan motors of under 1 horsepower and less than 460 volts)
- use electronically commutated motors, permanent split capacitor-type motors, or three-phase motors (for condenser fan motors of under 1 horsepower)
- use light sources with an efficacy of 40 lumens per watt or more, including ballast losses (if any), except that light sources with an efficacy of 40 lumens per watt or less, including ballast losses (if any), may be used in conjunction with a timer or device that turns off the lights within 15 minutes of when the walk-in freezer is not occupied by people.

In 2014, DOE updated its energy conservation standards for walk-in coolers and freezers. Minimum AWEF (Annual Walk-in Energy Factor) was set for refrigeration systems, as well as upper limits on energy consumption attributable to passage, freight, and display doors. DOE elected not to set new standards for the R-value of Walk-in Panels.

ENERGY CONSERVATION STANDARDS FOR WALK-IN COOLERS AND WALK-IN FREEZERS

Class descriptor	Class	Standard level
Refrigeration Systems Minimum AWEF (Btu/W-h)		
Dedicated Condensing, Medium Temperature, Indoor System, <9,000 Btu/h Capacity	DC.M.I, <9,000	5.61
Dedicated Condensing, Medium Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.M.I, ≥9,000	5.61
Dedicated Condensing, Medium Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.M.O, <9,000	7.60
Dedicated Condensing, Medium Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.M.O,≥9,000	7.60
Dedicated Condensing, Low Temperature, Indoor System, <9,000 Btu/h Capacity	DC.L.I, <9,000	$5.93 \cdot 10^{-6} \cdot Q + 2.33$
Dedicated Condensing, Low Temperature, Indoor System, ≥9,000 Btu/h Capacity	DC.L.I, ≥9,000	3.10
Dedicated Condensing, Low Temperature, Outdoor System, <9,000 Btu/h Capacity	DC.L.O, <9,000	$2.30 \cdot 10^{-4} \cdot Q + 2.73$
Dedicated Condensing, Low Temperature, Outdoor System, ≥9,000 Btu/h Capacity	DC.L.O, ≥9,000	4.79
Multiplex Condensing, Medium Temperature	MC.M	10.89
Multiplex Condensing, Low Temperature	MC.L	6.57
Panels Minimum R-value (h-ft2-°F/Btu)		
Structural Panel, Medium Temperature	SP.M	25
Structural Panel, Low Temperature	SP.L	32
Floor Panel, Low Temperature	FP.L	28
Non-Display Doors Maximum energy consumption (kWh/day) **		
Passage Door, Medium Temperature	PD.M	$0.05 \cdot A_{nd} + 1.7$
Passage Door, Low Temperature	PD.L	$0.14 \cdot A_{nd} + 4.8$
Freight Door, Medium Temperature	FD.M	$0.04 \cdot A_{nd} + 1.9$
Freight Door, Low Temperature	FD.L	$0.12 \cdot A_{nd} + 5.6$
Display Doors Maximum Energy Consumption (kWh/day) †		
Display Door, Medium Temperature	DD.M	$0.04 \cdot A_{dd} + 0.41$
Display Door, Low Temperature	DD.L	$0.15 \cdot A_{dd} + 0.29$

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Performance and Cost Characteristics » Commercial Ice Machines

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[6]	Typical	High	Typical	High	Typical	High
Output (pounds [lbs] per day)[1]	300	641	700	700	700	700	700	700	700	700	700	700
Cooling Capacity (Btu/h)[2]	1963	4194	4580	4580	4580	4580	4580	4580	4580	4580	4580	4580
Water Use per Hundred Pounds (gal/hundred lbs)[3]	20	25	25	20	15	15	20	15	20	15	20	15
Energy Use per Hundred Pounds (kWh/hundred lbs)	7.7	7.5	7.1	5.8	4.8	4.8	5.8	4.8	5.8	4.8	5.8	4.8
Annual Energy Use (kWh/y)[4]	3,185	2,502	1,675	1,478	1,190	1,190	1,330	1,071	1,197	964	1,077	868
Indexed Annual Efficiency[5]	1.00	1.27	1.90	2.15	2.68	2.68	2.39	2.97	2.66	3.30	2.96	3.67
Average Life (years)	8.0	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Retail Equipment Cost (2022$)	$2,146	$2,616	$2,946	$3,020	$3,368	$3,368	$3,020	$3,368	$3,020	$3,368	$3,020	$3,368
Total Installed Cost (with Bin)	$2,441	$3,626	$3,276	$3,350	$3,737	$3,737	$3,350	$3,737	$3,350	$3,737	$3,350	$3,737
Total Installed Cost (2022$/kBtu/h)	$1,244	$865	$715	$732	$816	$816	$732	$816	$732	$816	$732	$816
Annual Maintenance Cost (2022$)[7]	$826	$826	$800	$800	$800	$800	$800	$800	$800	$800	$800	$800
Annual Maintenance Cost (2022$/kBtu/h)	$421	$197	$175	$175	$175	$175	$175	$175	$175	$175	$175	$175

1. Based on the average output from the Compliance Certification Database and values within 2022 Automatic Commercial Ice Maker (ACIM) TSD.
2. Defined as the average heat load to remove the latent and sensible heat required to freeze the daily output capacity of ice.
3. Water use refers to potable water.
4. EPACT 2005 energy standards went into effect in 2010. The 2015 low values are based on this standard. In 2014, DOE set new standards for commercial ice machines, with compliance required by 2018. The unit characterized for 2012 and beyond uses data from this rulemaking. All units for 2020 and beyond are assumed to comply with the updated standard.
5. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use)/(Energy Use).
6. The ENERGY STAR category is based on minimum compliance with the ENERGY STAR v3.0 standard, which went into effect on January 28, 2018. According to this analysis, ENERGY STAR certification is typical for the small air-cooled ice-making head (IMH) unit characterized.
7. Maintenance cost is based on the average cost of equipment within the 700 lb/day output range and includes cleaning and maintaining refrigerant levels, replacing filters, checking water distribution lines for leaks, cleaning, sanitizing, and descaling the bin and water system. Maintenance cost decreases as the size of the ice machine (i.e. output) decreases.

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Performance and Cost Characteristics » Commercial Ice Machines

- Commercial ice machines are typically integrated with an insulated ice storage bin or mounted on top of a separate storage bin. The retail equipment cost includes the ice making head and the integrated storage bin. Commercial ice machine condensers are either air-cooled or water-cooled. Approximately 90% of all units are the air-cooled type.
- Commercial ice machine maintenance includes periodic cleaning (every 2 to 6 weeks) to remove lime and scale and sanitizing to kill bacteria. Some ice machines are self-cleaning/sanitizing.
- ENERGY STAR® updated its maximum energy consumption levels, in kilowatt-hours per 100 pounds of ice, for air-cooled ice machines that went into effect on January 28, 2018. These efficiency levels are based on the harvest rate, in pounds per 24 hours. (H). Water-cooled ice machines are not eligible for ENERGY STAR certification.
- **For this Advanced Case, a 10% reduction in energy consumption is projected over the Reference Case due to the adoption of more efficient refrigerants such as propane, which, while not currently required by EPA SNAP, are a source of possible efficiency improvements.**

ENERGY STAR Requirements for Air-Cooled Batch-Type Ice Makers			
Equipment Type	Applicable Ice Harvest Rate Range (lbs of ice/24 hrs)	Energy Consumption Rate (kWh/100 lbs ice)	Potable Water Use (gal/hundred lbs ice)
IMH	$200 \le H \le 1600$	$\le 37.72 * H^{-0.298}$	≤ 20.0
RCU	$400 \le H \le 1600$	$\le 22.95 * H^{-0.258} + 1.00$	≤ 20.0
	$1600 \le H \le 4000$	$\le -0.00011 * H + 4.60$	≤ 20.0
SCU	$50 \le H \le 450$	$\le 48.66 * H^{-0.326} + 0.08$	≤ 25.0

ENERGY STAR Requirements for Air-Cooled Continuous-Type Ice Makers		
Equipment Type	Energy Consumption Rate (kWh/hundred lbs ice)	Potable Water Use (gal/hundred lbs ice)
IMH	$\le 9.18 * H^{-0.057}$	≤ 15.0
RCU	$\le 6.00 * H^{-0.162} + 3.50$	≤ 15.0
SCU	$\le 59.45 * H^{-0.349} + 0.08$	≤ 15.0

EPACT 2005 issued standard levels for commercial ice machines with capacities between 50 pounds and 2500 pounds per 24-hour period that are manufactured or sold in the United States on or after January 1, 2010. The energy consumption is based on the harvest rate in pounds per 24 hours (H). In 2015, DOE finalized new standards for ACIMs extending coverage to flake, nugget, and tube-type machines and to capacities up to 4,000 pounds per 24 hours.

Equipment Type	Type of Cooling	Harvest Rate (lbs ice/24 hrs)	Maximum Energy Use (kWh/hundred lbs ice)	Maximum Condenser Water Use (gal/hundred lbs ice)
Ice Making Head	Water	<500	7.80-0.0055 H	200-0.022 H
		≥500 and <1,436	5.58-0.0011 H	200-0.022 H
		≥1,436	4.0	200-0.022 H
	Air	<450	10.26-0.0086 H	Not Applicable
		≥450	6.89-0.0011 H	Not Applicable
Remote Condensing (but not remote compressor)	Air	<1,000	8.85-0.0038 H	Not Applicable
		≥1,000	5.10	Not Applicable
Remote Condensing and Remote Compressor	Air	<934	8.85-0.0038 H	Not Applicable
		≥934	5.3	Not Applicable
Self Contained	Water	<200	11.40-0.019 H	191-0.0315 H
		≥200	7.60	191-0.0315 H
	Air	<175	18.0-0.0469 H	Not Applicable
		≥175	9.80	Not Applicable

Water use is for the condenser only and does not include potable water used to make ice.

2014 DOE Standards

Energy Conservation Standards for Batch-Type Automatic Commercial Ice Makers
Effective January 2018

Equipment Type	Type of Cooling	Harvest Rate lb ice/24 hours	Maximum Energy Use kWh/100 lb ice*	Maximum Condenser Water Use gal/100 lb ice**
Ice-Making Head	Water	<300	6.88 - 0.0055H	200 - 0.022H
		300 and <850	5.80 - 0.00191H	200 - 0.022H
		850 and <1,500	4.42 - 0.00028H	200 - 0.022H
		1500 and <2,500	4.0	200 - 0.022H
		2500 and <4,000	4.0	145
Ice-Making Head	Air	<300	10 - 0.01233H	Not Applicable
		300 and <800	7.05 - 0.0025H	Not Applicable
		800 and <1500	5.55 - 0.00063H	Not Applicable
		1500 and <4,000	4.61	Not Applicable
Remote Condensing (but not remote compressor)	Air	50 and <1,000	7.97 - 0.00342H	Not Applicable
		1,000 and <4,000	4.55	Not Applicable
Remote Condensing and Remote Compressor	Air	<942	7.97 - 0.00342H	Not Applicable
		942 and <4,000	4.75	Not Applicable
Self-Contained	Water	<200	9.5 - 0.019H	191 - 0.0315H
		200 and <2,500	5.7	191 - 0.0315H
		2500 and <4,000	5.7	112
Self-Contained	Air	<110	14.79 - 0.0469H	Not Applicable
		110 and <200	12.42 - 0.02533H	Not Applicable
		200 and <4,000	7.35	Not Applicable

Energy Conservation Standards for Continuous-Type Automatic Commercial Ice Makers
Effective January 2018

Equipment Type	Type of Cooling	Harvest Rate lb ice/24 hours	Maximum Energy Use kWh/100 lb ice*	Maximum Condenser Water Use gal/100 lb ice**
Ice-Making Head	Water	<801	6.48 - 0.00267H	180 - 0.0198H
		801 and <2,500	4.34	180 - 0.0198H
		2,500 and <4,000	4.34	130.5
Ice-Making Head	Air	<310	9.19 - 0.00629H	Not Applicable
		310 and <820	8.23 - 0.0032H	Not Applicable
		820 and <4,000	5.61	Not Applicable
Remote Condensing (but not remote compressor)	Air	<800	9.7 - 0.0058H	Not Applicable
		800 and <4,000	5.06	Not Applicable
Remote Condensing and Remote Compressor	Air	<800	9.9 - 0.0058H	Not Applicable
		800 and <4,000	5.26	Not Applicable
Self-Contained	Water	<900	7.6 - 0.00302H	153 - 0.0252H
		900 and <2,500	4.88	153 - 0.0252H
		2500 and <4,000	4.88	90
Self-Contained	Air	<200	14.22 - 0.03H	Not Applicable
		200 and <700	9.47 - 0.00624H	Not Applicable
		700 and <4,000	5.1	Not Applicable

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Performance and Cost Characteristics » Commercial Beverage Merchandisers

Final

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	4,689	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700
Size (ft^3)	27	27	27	27	27	27	27	27	27	27	27	27
Annual Energy Use (kWh/y)	1,829	1,635	1,380	1,141	902	902	1,141	902	1,084	857	1,030	814
Annual Energy Use / Volume ($kWh/ft^3/y$)[1]	68	73	55	35	26	26	35	26	35	26	35	26
Indexed Annual Efficiency[3]	1.00	1.12	1.33	1.60	2.03	2.03	1.60	2.03	1.69	2.13	1.78	2.25
Average Life (years)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Retail Equipment Cost (2022$)	$2,382	$2,051	$1,710	$2,762	$3,332	$3,332	$2,762	$3,332	$2,762	$3,332	$2,762	$3,332
Total Installed Cost (2022$)[4]	$2,382	$2,051	$1,710	$2,762	$3,332	$3,332	$2,762	$3,332	$2,762	$3,332	$2,762	$3,332
Total Installed Cost (2022$/kBtu/h)	$508	$436	$364	$588	$709	$709	$588	$709	$588	$709	$588	$709
Annual Maintenance Cost (2022$)	$108	$108	$95	$95	$95	$95	$95	$95	$95	$95	$95	$95
Annual Maintenance Cost (2022$/kBtu/h)	$23.03	$22.98	$20.21	$20.21	$20.11	$20.11	$20.21	$20.11	$20.21	$20.11	$20.21	$20.11

1. EPACT 2005 energy conservation standards went into effect in 2010. In 2015, DOE updated its energy conservation standards for commercial refrigeration equipment, including transparent-doored refrigerators with pull-down capability. Compliance with this standard is required by 2017. Units characterized for 2018 and beyond use data reported in this rulemaking's TSD. Units sold in 2022 and beyond are assumed to comply with this updated standard.
2. The ENERGY STAR category characterizes a unit that is compliant with ENERGY STAR v4, effective March 2017. This standard does not separately define units with pull-down capability.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use) / (Energy Use).
4. Beverage merchandisers are shipped ready to be plugged in, so installation costs are assumed to be negligible.

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Performance and Cost Characteristics » Commercial Beverage Merchandisers

Final

- EPACT 2005 sets maximum daily energy consumption levels, in kilowatt-hours per day, for commercial refrigerators with transparent doors and self-contained condensing unit designed for pull-down temperature applications (i.e., beverage merchandisers) and went into effect on January 1, 2010.
- In 2014, DOE updated its energy consumption standards for commercial refrigeration equipment, including beverage merchandisers, effective March 27, 2015. Both the DOE and EPCA standards are reported below.

Equipment Type	EPCA (2010)	DOE Standards (2017)
Beverage Merchandisers (PD.SC.M)	0.126xV + 3.51	0.11xV+0.81

- In 2013, EPA updated its ENERGY STAR specifications for glass-doored commercial refrigerators, which can be used as beverage merchandisers, effective October 1, 2014. These standards are also based on the volume of the unit (V). Note that ENERGY STAR does not have a separate equipment class for units with pull-down capability.

Beverage Merchandiser Size	0 < V < 15	15 ≤ V < 30	30 ≤ V < 50	50 ≤ V
Glass Door	0.118*V + 1.382	≤ 0.140*V + 1.050	≤ 0.088*V + 2.625	≤ 0.110*V + 1.500

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Performance and Cost Characteristics » Commercial Beverage Merchandisers

- The beverage merchandiser characterized in this report, which is the typical unit according to DOE's 2014 CRE rulemaking and additional analysis by Guidehouse, is a 27 cubic foot cooler with a single hinged, transparent door, bright lighting, and shelving with a nominal compressor size of 4,700 Btu/h.
- The efficiency of beverage merchandisers can be increased through the use of more efficient compressors, fluorescent lighting with electronic ballasts, LED lighting, and improved insulation.
- For the Reference Case, beverage merchandisers are assumed to be mature technologies with few technology advancements in the coming years that would dramatically improve the efficiency.
- **For this Advanced Case, the typical unit in 2030 is assumed to comply with DOE's updated energy conservation standards for commercial refrigeration**
- **By 2040, the adoption of vacuum insulated panels is assumed to occur, with the aid of decreased incremental costs due to increased R&D funding**
- **Beverage merchandisers may transition from HFC to more efficient propane.**
- **Projected installed costs for this Advanced Case are the same as the Reference Case, assuming increased R&D funding. Advanced energy-saving technologies are assumed to be made financially viable for operators by increased market incentives such as utility efficiency rebate programs and/or carbon pricing.**
- **This analysis finds that with increased R&D and market incentives for energy efficiency technologies, a limit of possible efficiency improvements for self-contained, vapor compression refrigeration systems will be reached by 2040 and a 5% decrease in energy use from 2030 to 2040.**

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Performance and Cost Characteristics » Commercial Refrigerated Vending Machines

Final

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR[2]	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	1,810	1,707	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810
Can Capacity	470	500	500	500	500	500	500	500	500	500	500	500
Size (ft^3)	26	35	35	35	35	35	35	35	35	35	35	35
Annual Energy Use (kWh/y)[1]	1,632	1,550	1,550	1,531	1,443	1,443	1,455	1,371	1,382	1,302	1,313	1,237
Annual Energy Use / Volume ($kWh/ft^3/y$)	63	44	44	44	41	41	42	39	39	37	38	35
Indexed Annual Efficiency[3]	1.00	1.05	1.05	1.07	1.13	1.13	1.12	1.19	1.18	1.25	1.24	1.32
Average Life (years)	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Retail Equipment Cost (2022$)	$3,209	$2,553	$3,059	$3,272	$3,520	$3,520	$3,272	$3,520	$3,272	$3,520	$3,272	$3,520
Total Installed Cost (2022$)	$3,320	$2,705	$3,276	$3,489	$3,737	$3,737	$3,489	$3,737	$3,489	$3,737	$3,489	$3,737
Total Installed Cost (2022$/kBtu/h)	$1,834	$1,585	$1,810	$1,928	$2,065	$2,065	$1,928	$2,065	$1,928	$2,065	$1,928	$2,065
Annual Maintenance Cost (2022$)[4]	$270	$270	$333	$333	$333	$333	$333	$333	$333	$333	$333	$333
Annual Maintenance Cost (2022$/kBtu/h)	$149	$149	$184	$184	$184	$184	$184	$184	$184	$184	$184	$184

1. Energy use for 2018 and beyond is estimated based on DOE's 2020 BVM Final Rule and the 2022 Compliance Certification Database.
2. The ENERGY STAR category assumes units are compliant with the ENERGY STAR v4 standard because combination units are currently not separately defined by ENERGY STAR. This standard went into effect on April 29, 2020. Our analysis finds ENERGY STAR certified equipment to be the most efficient currently available on the market.
3. Annual efficiency normalized to the efficiency of the 2012 installed base. Indexed Annual Efficiency = (2012 Energy Use)/(Energy Use).
4. Maintenance cost includes preventative maintenance costs such as checking and maintaining refrigerant charge levels, cleaning heat exchanger coils, and an annualized cost for refurbishments/remanufacturing.

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Performance and Cost Characteristics » Commercial Refrigerated Vending Machines

- DOE set federal energy efficiency standards for refrigerated vending machines. These standards set maximum daily energy consumption levels, in kilowatt-hours per day, for commercial refrigerated vending machines manufactured or sold in the United States on or after August 31, 2012. The daily energy consumption is based on the volume of the unit (V).
- In December 2015, DOE updated its energy conservation standards for beverage vending machines and defined two new product classes for combination vending machines. The energy conservation standard remains the same in the updated 2022 technical support document for vending machines. Compliance with these standards was required by 2019. For this analysis, compliance with these updated standards is assumed for equipment sold in 2022 and beyond. The updated standards and DOE equipment definitions are listed in the table below.

Equipment Type	Maximum Daily Energy Consumption
Class A (Transparent-Front)	MDEC= 0.052 × V + 2.43
Class B (Solid-Front)	MDEC = 0.052 × V + 2.20
Combination A	MDEC = 0.086 × V + 2.66
Combination B	MDEC = 0.111 × V + 2.04

ENERGY STAR® updated its maximum daily energy consumption efficiency levels, also in kilowatt-hours per day, for refrigerated vending machines that went into effect on April 29, 2020. These efficiency levels are based on refrigerated volume.

Equipment Class	Maximum daily energy consumption (kilowatt-hours per day)
Class A – a refrigerated bottled or canned beverage vending machine that is not a combination vending machine and in which 25% or more of the surface area on the front side of the beverage vending machine is transparent	MDEC = 0.04836 x V + 2.2599
Class B – any refrigerated bottled or canned beverage vending machine that is not considered to be Class A and is not a combination vending machine	MDEC = 0.04576 x V+1.936
Combination A – a combination vending machine where 25% or more of the surface area on the front side of the beverage vending machine is transparent	MDEC = 0.07998 x V + 2.4738
Combination B – a combination vending machine that is not considered to be Combination A	MDEC = 0.09768 x V + 1.7952

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Performance and Cost Characteristics » Commercial Refrigerated Vending Machines

Final

- DOE set federal energy efficiency standards for refrigerated vending machines in 2009. These standards set maximum daily energy consumption levels, in kWh/day, for commercial refrigerated vending machines manufactured and/or sold in the United States on or after August 31, 2012. The daily energy consumption is based on the volume of the unit (V).
  - Refrigerated Vending Machines that are fully-cooled (Type A) $\leq 0.055*V + 2.56$
  - Refrigerated Vending Machines that are zone-cooled (Type B) $\leq 0.073*V + 3.16$
- ENERGY STAR® updated its maximum daily energy consumption efficiency levels, also in kWh/day, for refrigerated vending machines, which went into effect on March 1, 2013. These efficiency levels are based on refrigerated volume.

Equipment Type	Maximum Daily Energy Consumption	Low Power Mode Requirement
Class A (Transparent-Front)	MDEC= 0.0523 x V + 2.432	Hard-wired controls and/or software capable of placing the machine into a low power mode during periods of extended inactivity while still connected to its power source
Class B (Solid-Front)	MDEC = 0.0657 x V + 2.844	

- **Currently, stakeholders such as Coca Cola have indicated a preference for CO_2 refrigerant, which is less efficient. However, this Advanced Case scenario assumes a shift to more efficient propane for cost and energy consumption projections due to the superior efficiency of propane refrigerant.**
- **By 2040, the adoption of vacuum insulated panels is assumed to occur, with the aid of decreased incremental costs due to increased R&D funding**
- **Projected installed costs for this Advanced Case are higher than the Reference Case, even assuming increased R&D funding. Advanced energy-saving technologies are assumed to be made financially viable for operators by increased market incentives such as utility efficiency rebate programs and/or carbon pricing.**
- **This analysis finds that with increased R&D and market incentives for energy efficiency technologies, a limit of possible efficiency improvements for self-contained, vapor compression refrigeration systems will be reached by 2040.**

In December 2015, DOE updated its energy conservation standards for beverage vending machines, and defined two new product classes for combination vending machines Compliance with these standards is required by 2019. For this analysis, compliance with these updated standards is assumed for equipment sold in 2020 and beyond. The updated standards and DOE equipment definitions are listed in the table below.

Equipment Class	Maximum daily energy consumption (kilowatt hours per day)
Class A – a refrigerated bottled or canned beverage vending machine that is not a combination vending machine and in which 25 percent or more of the surface area on the front side of the beverage vending machine is transparent	MDEC = 0.052 x V + 2.43
Class B – any refrigerated bottled or canned beverage vending machine that is not considered to be Class A and is not a combination vending machine	MDEC = 0.052 x V + 2.20
Combination A – a combination vending machine where 25 percent or more of the surface area on the front side of the beverage vending machine is transparent	MDEC = 0.086 x V + 2.66
Combination B – a combination vending machine that is not considered to be Combination A	MDEC = 0.111 x V + 2.04

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Commercial Ventilation

Final

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Performance and Cost Characteristics » Commercial Constant Air Volume

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average[3]	Low[4,5]	Typical[4,6]	High[4,7]	ENERGY STAR	Typical[4,6]	High[4,7]	Typical[4,6]	High[4,7]	Typical[4,6]	High[4,7]
System Airflow (CFM)	15,000	16,300	16,300	16,300	16,300	N/A	16,300	16,300	16,300	16,300	16,300	16,300
System Fan Power (kW)	11.56	11.56	11.56	10.98	10.78	N/A	10.98	10.78	10.98	10.78	10.98	10.78
Specific Fan Power (W/CFM)	0.771	0.709	0.709	0.674	0.661	N/A	0.674	0.661	0.674	0.661	0.674	0.661
Annual Fan Energy Use (kWh/y)[1]	43,924	23,038	23,038	21,886	20,792	N/A	20,792	19,752	19,752	18,765	18,765	17,826
Average Life (years)	35	35	35	35	35	N/A	35	35	35	35	35	35
Total Installed Cost (2022$)[2]	$80,288	$83,083	$83,083	$86,901	$90,651	N/A	$86,901	$90,651	$86,901	$90,651	$86,901	$90,651
Annual Maintenance Cost (2022$)	$1,054	$1,054	$1,054	$1,054	$1,054	N/A	$1,054	$1,054	$1,054	$1,054	$1,054	$1,054
Total Installed Cost (2022$/thousand CFM)	$5,353	$5,097	$5,097	$5,331	$5,561	N/A	$5,331	$5,561	$5,331	$5,561	$5,331	$5,561
Annual Maintenance Cost (2022$/thousand CFM)	$70	$65	$65	$65	$65	N/A	$65	$65	$65	$65	$65	$65

1. Based on 3800 operating hours per year (ADL, 1999) and typical zone air flow requirement profile (ASHRAE S45.11-2012)
2. Total installed cost of 16,300 CFM constant air volume (CAV) air handling unit (AHU) and hypothetical supply ductwork layout
3. Based on ASHRAE 90.1-2016 and 2019 fan power limit (Table 6.5.3.1.1-1) with no pressure drop adjustment. Assumed 80% motor load and 91% motor efficiency
4. ASHRAE 90.1-2016 and 2019 Section 6.5.3.2 require minimum two-speed fan control (no longer always constant volume).
5. Two-speed variable frequency drive (VFD)
6. Modulating VFD
7. Modulating custom engineered VFD

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Performance and Cost Characteristics » Commercial Constant Air Volume

Final

- Constant air volume (CAV) ventilation systems are common, inexpensive, air-side HVAC systems that operate in response to a single control zone. Historically, these systems provide a constant flow rate of air (typically a mix of recirculated and outside air) and adjust the supply temperature of that air in order to maintain the space temperature setpoint. Beginning with ASHRAE 90.1-2013 and continued in ASHRAE 90.1-2019, new CAV ventilation systems were mandated to have at least two fan speed settings with the requirement of a maximum 40% power at 66% flow. Systems with variable speed fans are increasingly popular, making the term "constant air volume" somewhat of a misnomer for this system type. This analysis examines only the fan energy of the CAV system.
- There is movement in the industry and in energy codes to reduce fan power. ASHRAE 90.1 includes fan power limits for CAV systems. Fan power can be minimized through good design practice (efficient duct layout, low pressure drop ductwork, filters, coils), proper fan selection, and high efficiency type fans. ASHRAE 90.1-2019 now requires a minimum fan efficiency grade (FEG, based on AMCA 205-12: Energy Efficiency Classification for Fans) of 67 and a design operating fan efficiency within 15% of the maximum fan total efficiency. There are exceptions to this requirement, including packaged systems such as the CAV system type considered here. Still the fan power limits are expected to become more stringent, and fan efficiency will become more important throughout the industry.
- The unit characterized in this report is a 16,300 CFM CAV system. The average commercial building is approximately 16,300 square feet (CBECS 2018). Assuming 1 CFM is needed per square foot of floor area results in a 16,300 CFM air handling unit.
- A 16,300 CFM CAV packaged indoor air handling unit with cooling and heating coils can be installed for approximately $71,829 (RS Means 2022). Ductwork would cost approximately $9,272 additional ($81,101 total). A two-speed motor (estimated $500 incremental cost) and variable frequency drive (estimated $5,800) add cost. Custom engineered variable frequency drives (estimated $9,550) and premium efficiency motors (estimated additional $1,500) add an additional cost to the system.
- Annual maintenance cost assumes 8 hours worth of labor by a technician to perform the necessary tasks (e.g., filter replacement, draining condenser water, etc.)
- ASHRAE Standard 90.1, which is used as a basis for most state energy codes, limits the fan power (brake HP or nameplate HP) for CAV systems. The 2016 version of Standard 90.1 was used to represent the 2018 minimum efficiency level (state energy codes typically refer to older versions of Standard 90.1 due to code revision cycles).
- Fan energy is affected by several factors, including fan type (e.g., centrifugal, axial), fan blade shape (e.g., forward-curved, backward-curved, backward-inclined, airfoil), drive type (belt or direct), configuration (plenum or housed centrifugal), system effects, duct design, filter and coil pressure drops, motor efficiency, and speed and flow control.
- **For this Advanced Case, the projections from 2030 to 2050 for system fan power and annual fan energy use assume a 5% improvement per decade based on the assumption that use of variable frequency drives and incremental improvements in technology will increase.**

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Performance and Cost Characteristics » Commercial Variable Air Volume

Final

Lower annual energy use compared with Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average[3]	Low[4]	Typical[5]	High[6]	ENERGY STAR	Typical[6]	High[6,7]	Typical[6,7]	High[6,7]	Typical[6,7]	High[6,7]
System Airflow (CFM)	15,000	16,300	16,300	16,300	16,300	N/A	16,300	16,300	16,300	16,300	16,300	16,300
System Fan Power (kW)	15.99	15.99	15.99	15.99	15.99	N/A	15.99	15.19	15.99	15.19	15.99	15.19
Specific Fan Power (W/CFM)	1.066	1.066	0.981	0.981	0.981	N/A	0.981	0.932	0.981	0.932	0.981	0.932
Annual Fan Energy Use (kWh/yr)[1]	24,699	24,082	24,082	22,878	21,734	N/A	21,734	20,647	20,647	19,615	19,615	18,634
Average Life (yrs)	28	28	28	28	28	N/A	28	28	28	28	28	28
Total Installed Cost (2022$)[2]	$103,327	$110,414	$118,814	$124,495	$124,995	N/A	$124,495	$124,995	$124,495	$124,995	$124,495	$124,995
Annual Maintenance Cost (2022$)	$1,054	$1,054	$1,054	$1,054	$1,054	N/A	$1,054	$1,054	$1,054	$1,054	$1,054	$1,054
Total Installed Cost (2022$/1000 CFM)	$6,888	$6,774	$7,289	$7,638	$7,668	N/A	$7,638	$7,668	$7,638	$7,668	$7,638	$7,668
Annual Maintenance Cost (2022$/1000 CFM)	$70	$65	$65	$65	$65	N/A	$65	$65	$65	$65	$65	$65

1. Based on 3800 operating hours per year (ADL, 1999) and typical zone air flow requirement profile (ASHRAE S45.11-2012)
2. Total installed cost of 16,300 CFM VAV AHU, VFD, (10) VAV boxes, (10) VAV controllers with associated space temperature sensor, and hypothetical supply ductwork layout
3. Based on ASHRAE 90.1-2016 and 2019 fan power limit (Table 6.5.3.1.1-1) with no pressure drop adjustment. Assumed 80% motor load and 91% motor efficiency
4. ASHRAE 90.1-2016 and 2019 Section 6.5.3.2 minimum power-flow requirement
5. ASHRAE 90.1-2019 fan power limit and typical VAV power-flow relationship for 40%-100% flow
6. ASHRAE 90.1-2019 fan power limit and typical VAV power-flow relationship for 30%-100% flow
7. High aerodynamic efficiency fan

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Performance and Cost Characteristics » Commercial Variable Air Volume

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- Variable air volume (VAV) ventilation systems are the most common multi-zone system type specified today for conditioning commercial buildings. These systems provide conditioned air to multiple zone terminal units (VAV boxes) that use dampers to modulate the amount of cool air to each zone. An individual zone thermostat controls the VAV box damper to allow more or less cooling. If a zone requires heating, then the VAV box provides the minimum flow rate and typically includes a reheat coil to meet the space temperature setpoint. As VAV box dampers close in the system, a variable frequency drive reduces fan speed and flow continuously to meet current requirements.
- This analysis examines only the fan energy of the VAV system. VAV systems vary fan speed and flow to meet space conditioning requirements; minimum flow settings apply for DX cooling stages and gas furnace heating stages. Most hours of operation are much lower than full speed, and fan power varies with the cube of fan speed according to fan affinity laws. The 2012 ASHRAE Handbook: HVAC Systems and Equipment (p. 45.11) provided the typical flow profile used for this analysis. The unit characterized in this report is a 16,300 CFM VAV system.
- There is movement in the industry and in energy codes to reduce fan power. ASHRAE 90.1 includes fan power limits for VAV systems. Fan power can be minimized through good design practice (efficient duct layout, low pressure drop ductwork, filters, coils), proper fan selection, and high efficiency type fans. ASHRAE 90.1-2019 now requires a minimum fan efficiency grade (FEG, based on AMCA 205-12: Energy Efficiency Classification for Fans) of 67 and a design operating fan efficiency within 15% of the maximum fan total efficiency. There are exceptions to this requirement, including packaged systems such as the VAV system type considered here. Still the fan power limits are expected to become more stringent, and fan efficiency will become more important throughout the industry.
- A 16,300 CFM VAV packaged indoor air handling unit with cooling and heating coils can be installed for approximately $82,023 (RS Means 2022). Ductwork and (10) VAV boxes with reheat would cost approximately an additional $28,272. (10) VAV controllers and the associated space temperature sensor would cost approximately $8,400 ($118,695 total). A 15 hp variable frequency drive (estimated $5,800) is an additional cost.
- ASHRAE Standard 90.1, which is used as a basis for most state energy codes, limits the fan power for VAV systems (brake HP or nameplate HP). The 2016 version of Standard 90.1 was used to represent the 2018 minimum efficiency level (state energy codes typically refer to older versions of Standard 90.1 due to code revision cycles).
- Annual maintenance cost assumes 8 hours worth of labor by a technician to perform the necessary tasks (e.g., filter replacement, draining condenser water, etc.)
- Fan energy is affected by several factors, including fan type (e.g., centrifugal, axial), fan blade shape (e.g., forward-curved, backward-curved, backward-inclined, airfoil), drive type (belt or direct), configuration (plenum or housed centrifugal), system effects, duct design, filter and coil pressure drops, and motor VFD efficiency.
- **For this Advanced Case, the projections from 2030 to 2050 for system fan power and annual fan energy use assume a 5% improvement per decade based on the assumption use of variable frequency drives and incremental improvements in technology will increase.**

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Performance and Cost Characteristics » Commercial Fan Coil Units

Final

Same as Reference Case

DATA	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average[5]	Low[3]	Typical[5]	High[6]	ENERGY STAR	Typical[4,6]	High[4,7]	Typical[4,7]	High[4,8]	Typical[4,8]	High[4,8,9]
System Airflow (CFM)	800	800	800	800	800	N/A	800	800	800	800	800	800
System Fan Power (kW)	0.241	0.241	0.241	0.148	0.148	N/A	0.141	0.134	0.134	0.136	0.136	0.129
Specific Fan Power (W/CFM)	0.302	0.302	0.301	0.185	0.185	N/A	0.176	0.167	0.167	0.170	0.170	0.162
Annual Fan Energy Use (kWh/y)[1]	543	542	542	333	333	N/A	316	301	301	306	306	291
Average Life (years)	37	37	37	37	37	N/A	37	37	37	37	37	37
Total Installed Cost (2022$)[2]	$2,845	$2,688	$3,038	$3,521	$3,961	N/A	$3,961	$4,161	$3,961	$4,161	$3,961	$4,161
Annual Maintenance Cost (2022$)	$117	$117	$117	$117	$117	N/A	$117	$117	$117	$117	$117	$117
Total Installed Cost (2022$/thousand CFM)	$3,557	$3,360	$3,798	$4,401	$4,951	N/A	$4,951	$5,201	$4,951	$5,201	$4,951	$5,201
Annual Maintenance Cost (2022$/thousand CFM)	$146	$146	$146	$146	$146	N/A	$146	$146	$146	$146	$146	$146

1. Based on 2250 operating hours per year (ADL, 1999) and typical zone air flow requirement profile (ASHRAE S45.11-2012)
2. Total installed cost of 2-ton horizontal two-pipe fan coil unit, housing, and controls
3. Based on ASHRAE 90.1-2016 and 2019 fan power limit (Table 6.5.3.1.1-1) with no pressure drop adjustment. Assumed 80% motor load and 91% motor efficiency
4. Based on ASHRAE 90.1-2016 and 2019 Section 6.5.3.6 requirement of electronically commutated or 70+% efficient fan motor
5. Permanent split capacitor fan motor
6. Electronically commutated fan motor (single speed)
7. Electronically commutated fan motor (two-speed)
8. Electronically commutated fan motor (variable speed)
9. High aerodynamic efficiency fan

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Performance and Cost Characteristics » Commercial Fan Coil Units

- Commercial fan coil units (FCUs) are self-contained, mass-produced assemblies that provide cooling, heating, or cooling and heating, but they do not include the source of cooling or heating. The unit characterized in this report is a cooling only (two-pipe), horizontal unit with housing and controls. Fan coil units are typically installed in or adjacent to the space being served and have no (or very limited) ductwork.
- According to manufacturer literature, the cooling capacity for a nominal 800 CFM fan coil unit is about 2 tons. This analysis examines only the fan energy of FCUs.
- Fan coil unit fan motors can be shaded pole, a single-phase AC motor with offset start winding and no capacitor; PSC, a single-phase AC motor with offset start winding with capacitor; or ECM, an AC electronically commutated permanent magnet DC motor. PSC motors are currently the most common motor type in FCUs, but manufacturers also offer single speed, two speed, and ECM motors as an option. ASHRAE 90.1-2019 requires an electronically commutated fan motor (or minimum motor efficiency of 70%) for this system.
- There is movement in the industry and in energy codes to reduce fan power. ASHRAE 90.1 includes fan power limits for FCUs. Fan power can be minimized through good design practice and high efficiency type fans. ASHRAE 90.1-2019 now requires a minimum fan efficiency grade (FEG, based on AMCA 205-12: Energy Efficiency Classification for Fans) of 67 and a design operating fan efficiency within 15% of the maximum fan total efficiency. There are exceptions to this requirement, including small systems such as the FCU considered here. Still the fan power limits are expected to become more stringent, and fan efficiency will become more important throughout the industry.
- Fan coil units have higher maintenance costs than central air systems due to the distributed nature of the system. For each unit, the filters must be changed, and drain systems must be flushed periodically.
- ASHRAE Standard 90.1, which is used as a basis for most state energy codes, limits the fan power (brake HP or nameplate HP). The 2016 version of Standard 90.1 was used to represent the 2018 minimum efficiency level (state energy codes typically refer to older versions of Standard 90.1 due to code revision cycles).
- Fan energy is affected by several factors, including fan type configuration, filter and coil pressure drops, motor efficiency, and fan speed control.

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Final

Appendix A
Data Sources

Guidehouse
1200 19th Street, NW, Suite 700
Washington, D.C. 20036

And

Leidos
8301 Greensboro Drive
McLean, VA 22102

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Residential Lighting

Final

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Data Sources» Residential General Service LED Lamps (60 Watt Equivalent)

DATA SOURCES	2015	2020	2022				2023**	2030		2040		2050	
	Installed Stock Average		Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources» Residential General Service Filament-LED Lamps (60 Watt Equivalent)

DATA SOURCES	2015	2020	2022				2023**	2030		2040		2050	
	Installed Stock Average		Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources» Residential Reflector LED BR30

DATA SOURCES	2015	2020	2022				2023**	2030		2040		2050	
	Installed Stock Average		Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)							DOE, 2017						
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A		Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Reflector LED PAR38

DATA SOURCES	2015	2020	2022				2023**	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs			N/A		Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Cost (2022$/klm)	Calculated												
Labor Cost (2022$/h)	N/A												
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)	Calculated						N/A	Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Residential Linear LED Replacement Lamp 2-Lamp System

DATA SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	LED Webscrape Database	DOE Webscrape Database	Distributor Websites			Calculated					
Lamp Lumens						Assume Same as 2022 Typical and High					
Lamp Efficacy (lm/W)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage	Calculated										
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)	N/A										
CRI	2016 EIA Ref. Case	Distributor Websites	Distributor Websites								
Correlated Color Temperature (CCT)	2016 EIA Ref. Case										
Average Lamp Life (thousand hours)	LED Webscrape Database	DOE Web Scrape Database									
Annual Operating Hours (h/y)	DOE, 2017										
Lamp Price (2022$)	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Calculated					
Ballast Price (2022$)		N/A									
Fixture Price (2022$)											
Lamp Cost (2022$/klm)	Calculated										
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)	N/A										
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)	Calculated										
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Residential Linear LED Luminaire

DATA SOURCES	2015	2020	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A										
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Calculated					
System Lumens						Assume Same as 2022 Typical and High					
System Efficacy (lm/W)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Efficiency (BLE)	N/A										
CRI	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Distributor Websites					
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)	DOE, 2017										
Lamp or Luminaire Price (2022$)	LED Webscrape Database	DOE Web Scrape Database	Distributor Websites			Calculated					
Ballast Price (2022$)	N/A										
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)	2016 EIA Ref. Case		2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)			N/A								
Total Installed Cost (2022$)	Calculated										
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources» Residential Outdoor Lamps (Security: LED PAR38)

DATA SOURCES	2015	2020	2022				2023*	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Same as Residential LED PAR38												
Lamp Lumens													
Lamp Efficacy (lm/W)													
CRI													
Correlated Color Temperature (CCT)													
Average Lamp Life (1000 hrs)													
Annual Operating Hours (hrs/yr)													
Lamp Price (2022$)													
Lamp Cost (2022$/klm)													
Labor Cost (2022$/hr)													
Labor Lamp Installation (hr)													
Total Installed Cost (2022$)													
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources» Residential Outdoor Lamps (Porch: LED A-Type)

DATA SOURCES	2015	2020	2022				2023*	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR*	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)			Calculated					Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
CRI			Distributor Websites or Product Catalogs				N/A	Assume Unchanged					
Correlated Color Temperature (CCT)													
Average Lamp Life (thousand hours)								Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	2020 DOE LED Pricing Analysis	Distributor Websites or Product Catalogs			N/A	DOE, 2017	Model DOE Goals Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Lamp Price (2022$)													
Lamp Cost (2022$/klm)							Calculated						
Labor Cost (2022$/h)							N/A						
Labor Lamp Installation (hours)													
Total Installed Cost (2022$)							Calculated						
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial General Service 100W Equivalent LED Replacement Lamp in Recessed Can Fixture

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated											
System Lumens*													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	N/A	Assume Unchanged					
Correlated Color Temperature (CCT)						N/A							
Average Lamp Life (thousand hours)						ENERGY STAR, 2020		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)				Assume Unchanged	
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A						N/A					
Fixture Price (2022$)*													
Lamp Cost (2022$/klm)		Calculated						Calculated					
System (l/b/f) Cost (2022$/klm)		N/A						N/A					
Labor Cost (2022$/h)		2016 EIA Reference Case	2022 RS Means Online					2022 RS Means Online					
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)		Calculated						Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial LED Reflector Lighting (PAR38)

DATA SOURCES	2012	2018	2022				2023	2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Standard	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	DOE, 2022	Calculated					
Lamp Lumens								Assume Unchanged					
Lamp Efficacy (lm/W)								Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated											
System Lumens*													
System Efficacy (lm/W)													
Ballast Efficiency (BLE)													
CRI		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			ENERGY STAR, 2020	N/A	Assume Unchanged					
Correlated Color Temperature (CCT)						N/A							
Average Lamp Life (thousand hours)						ENERGY STAR, 2020		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)				Assume Unchanged	
Annual Operating Hours (h/y)	DOE, 2017												
Lamp Price (2022$)	2016 EIA Reference Case	Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	Distributor Websites or Product Catalogs			N/A		Model Reference Scenario, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A						N/A					
Fixture Price (2022$)													
Lamp Cost (2022$/klm)		Calculated						Calculated					
System (l/b/f) Cost (2022$/klm)		N/A						N/A					
Labor Cost (2022$/h)		2016 EIA Reference Case	2022 RS Means Online					2022 RS Means Online					
Labor System Installation (hours)													
Labor Lamp Change (hours)													
Total Installed Cost (2022$)		Calculated						Calculated					
Annual Maintenance Cost (2022$)													
Total Installed Cost (2022$/klm)													
Annual Maintenance Cost (2022$/klm)													

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Data Sources » Commercial 4-ft Linear LED Replacement Lamp in 2-Lamp System

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	LED Webscrape Database	Distributor Websites			Calculated					
Lamp Lumens						Assume Same as 2022 Typical and High					
Lamp Efficacy (lm/W)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated									
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		N/A									
CRI		Distributor Websites									
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		LED Webscrape Database	Distributor Websites			Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A									
Fixture Price (2022$)											
Lamp Cost (2022$/klm)		Calculated									
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)		2016 EIA Ref. Case	2022 RS Means Online								
Labor System Installation (hours)		N/A									
Labor Lamp Change (hours)		Assume unchanged									
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 4-ft Linear LED Luminaire to Replace 2-Lamp Systems

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	2016 EIA Ref. Case	N/A									
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage		LED Webscrape Database	Distributor Websites			Calculated					
System Lumens						Assume Same as 2022 Typical and High					
System Efficacy (lm/W)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Efficiency (BLE)		N/A				N/A					
CRI		Distributor Websites									
Correlated Color Temperature (CCT)											
Average Lifetime (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp or Luminaire Price (2022$)		LED Webscrape Database	Distributor Websites			Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)		N/A									
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)		Calculated									
Labor Cost (2022$/h)		2016 EIA Ref. Case	2022 RS Means Online								
Labor System Installation (hours)		2022 RS Means Online									
Labor Lamp Change (hours)		N/A									
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 8-ft Linear LED Replacement Lamp for a 2-Lamp System

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	2016 EIA Ref. Case, 2015 typical	Distributor Websites			Calculated					
Lamp Lumens						Assume Same as 2022 Typical and High					
Lamp Efficacy (lm/W)			Calculated			Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Wattage		Calculated				Calculated					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		N/A									
CRI		2016 EIA Ref. Case, 2015 typical	Distributor Websites								
Correlated Color Temperature (CCT)											
Average Lamp Life (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp Price (2022$)		2016 EIA Ref. Case, 2015 typical	Distributor Websites			Calculated					
Ballast Price (2022$)			N/A								
Fixture Price (2022$)											
Lamp Cost (2022$/klm)			Calculated								
System (l/b/f) Cost (2022$/klm)											
Labor Cost (2022$/h)			2022 RS Means Online								
Labor System Installation (hours)		N/A									
Labor Lamp Change (hours)		Chapter 8; Table 8.2.4 of GSFL IRL Preliminary Analysis TSD (DOE, 2013)									
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial 8-ft Linear LED Luminaire Replacement for a 2-Lamp System

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A	N/A									
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage		2016 EIA Ref. Case, 2015 typical	Distributor Websites			Calculated					
System Lumens						Assume Same as 2022 Typical and High					
System Efficacy (lm/W)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Efficiency (BLE)		N/A									
CRI		2016 EIA Ref. Case, 2015 typical	Distributor Websites								
Correlated Color Temperature (CCT)											
Average Lifetime (thousand hours)											
Annual Operating Hours (h/y)		DOE, 2017									
Lamp or Luminaire Price (2022$)		2016 EIA Ref. Case, 2015 typical	Distributor Websites								
Ballast Price (2022$)		N/A									
Fixture Price (2022$)											
Lamp Cost (2022$/klm)											
System (l/b/f) Cost (2022$/klm)		Calculated									
Labor Cost (2022$/h)		2016 EIA Ref. Case, 2015 typical	2022 RS Means Online								
Labor System Installation (hours)											
Labor Lamp Change (hours)		N/A									
Total Installed Cost (2022$)		Calculated									
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial LED Low-Bay Luminaire

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A										
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	N/A	Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency		N/A		N/A		N/A					
CRI		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs		Assume Unchanged					
Correlated Color Temperature (CCT)											
Average Lifetime (thousand hours)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017							
Lamp or Luminaire Price (2022$)	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)											
Fixture Price (2022$)											
Lamp Cost (2022$/klm)		N/A		N/A		N/A					
System (l/b/f) Cost (2022$/klm)		Calculated		Calculated							
Labor Cost (2022$/h)		2016 EIA Reference Case		2022 RS Means Online		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)	Calculated			Calculated		Calculated					
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Data Sources » Commercial LED High-Bay Luminaire

DATA SOURCES	2012	2018	2022			2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	Typical	High	Typical	High	Typical	High
Lamp Wattage	N/A										
Lamp Lumens											
Lamp Efficacy (lm/W)											
System Wattage	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	N/A	Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
System Lumens											
System Efficacy (lm/W)											
Ballast Efficiency (BLE)		N/A		N/A		N/A					
CRI		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)		Distributor Websites or Product Catalogs		Assume Unchanged					
Correlated Color Temperature (CCT)						Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Average Lifetime (thousand hours)											
Annual Operating Hours (h/y)	DOE, 2017			DOE, 2017		DOE, 2017					
Lamp or Luminaire Price (2022$)	2016 EIA Reference Case	Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)	N/A	Distributor Websites or Product Catalogs		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Ballast Price (2022$)											
Fixture Price (2022$)				N/A		N/A					
Lamp Cost (2022$/klm)		N/A									
System (l/b/f) Cost (2022$/klm)		Calculated		Calculated							
Labor Cost (2022$/h)		2016 EIA Reference Case		2022 RS Means Online		Model, Energy Savings Forecast of Solid-State Lighting in General Illumination Applications (Navigant, 2019)					
Labor System Installation (hours)											
Labor Lamp Change (hours)											
Total Installed Cost (2022$)	Calculated			Calculated		Calculated					
Annual Maintenance Cost (2022$)											
Total Installed Cost (2022$/klm)											
Annual Maintenance Cost (2022$/klm)											

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Refrigeration

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Data Sources» Commercial Compressor Rack Systems

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)	ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Median Store Size (ft^2)	Food Marketing Institute (FMI), 2012	CBECS 2018										
Power Input (kW)	Copeland, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use (MMWh/y)	ADL, 1996 / NCI Analysis, 2015	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Indexed Annual Efficiency	Calculated											
Average Life (years)	Kysor-Warren, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$)	NCI, 2009 / NCI Analysis, 2012	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources» Commercial Condensers

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Total Capacity (kBtu/h)	NCI Analysis, 2008 /Heatcraft, 2008 /ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Median Store Size (ft^2)	Food Marketing Institute (FMI), 2012	CBECS 2018										
Power Input (kW)	NCI Analysis, 2008 /Heatcraft, 2008 /ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use (MMWh/y)	NCI Analysis, 2008 /ADL, 1996	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Indexed Annual Efficiency	Calculated											
Average Life (years)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$)	NCI Analysis, 2008 /Heatcraft, 2008 /RS Means, 2007	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources» Commercial Supermarket Display Cases

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	ENERGY STAR	High	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Median Store Size (ft^2)	Food Marketing Institute (FMI), 2012	CBECS 2018										
Case Length (ft)	DOE, 2016: CRE Report / Guidehouse Analysis 2022											
Annual Energy Use (kWh/y)[1,2]	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use / Case Length (kWh/ft)	Calculated											
Indexed Annual Efficiency[3]	Calculated											
Average Life (years)	DOE, 2007 / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / The Restaurant Store										
Total Installed Cost (2022$)	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)[4]	DOE, 2007 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources» Commercial Reach-In Refrigerators

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report										
Size (ft^3)	ADL, 1996 / Distributor Web Sites	DOE, 2014: CRE Report										
Annual Energy Use (kWh/y)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022										
Annual Energy Use / Volume (kWh/y/ft^3)	NCI Analysis, 2012	Calculated										
Indexed Annual Efficiency	Calculated											
Average Life (years)	Calculated											
Retail Equipment Cost (2022$)	ACEEE, 2002	DOE, 2014: CRE TSD										
Total Installed Cost (2022$)	ADL, 1996/ Distributor Web Sites / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022 / The Restaurant Store										
Total Installed Cost (2022$/kBtu/h)	Distributor Web Sites / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$)	Calculated											
Annual Maintenance Cost (2022$/kBtu/h)	NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources» Commercial Reach-In Freezers

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	ADL, 1996 / NCI Analysis, 2008	DOE, 2016: CRE Report										
Size (ft^3)	ADL, 1996 / Distributor Web Sites	DOE, 2016: CRE Report										
Annual Energy Use (kWh/y)	ADL, 1996 / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use / Volume ($kWh/y/ft^3$)	NCI Analysis, 2012	Calculated										
Indexed Annual Efficiency	Calculated											
Average Life (years)	ACEEE, 2002	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996/ Distributor Web Sites / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022 / The Restaurant Store										
Total Installed Cost (2022$)	Distributor Web Sites / NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	NCI Analysis, 2008	DOE, 2016: CRE Report / Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources» Commercial Walk-In Refrigerators

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE CRE Report 2016/CCMS 2022/Guidehouse Analysis 2022											
Size (ft^2)	DOE 2014 WICF TSD/Guidehouse Analysis 2022											
Annual Energy Use (kWh/y)	ADL, 1996/PG&E, 2004/NCI Analysis, 2008	DOE CRE Report 2016/Guidehouse Analysis 2022										
Annual Energy Use / Area ($kWh/ft^2/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Insulated Box Average Life (years)	ADL, 1996/PG&E, 2004	DOE CRE Report 2016/Guidehouse Analysis 2022										
Compressor Average Life (years)	ADL, 1996/PG&E, 2004	DOE CRE Report 2016/Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996/Distributor Web Sites/NCI Analysis, 2008	DOE CRE Report 2016/Webstaurant 2022/Guidehouse Analysis 2022										
Total Installed Cost (2022$)	ADL, 1996/Distributor Web Sites/NCI Analysis, 2008	DOE CRE Report 2016/Webstaurant 2022/Guidehouse Analysis 2023										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	ADL, 1996/FMI, 2005/NCI Analysis, 2008	DOE CRE Report 2016/Guidehouse Analysis 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources» Commercial Walk-In Freezers

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	ADL, 1996 / NCI Analysis, 2008	DOE CRE Report 2016 / CCMS 2022 / Guidehouse Analysis 2022										
Size (ft^2)	ADL, 1996 / NCI Analysis, 2008	Guidehouse Analysis 2022										
Annual Energy Use (kWh/y)	ADL, 1996 / PG&E, 2004 / NCI Analysis, 2008	Guidehouse CRE Report 2016										
Annual Energy Use / Area ($kWh/ft^2/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Insulated Box Average Life (years)	ADL, 1996 / PG&E, 2004	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Compressor Average Life (years)	ADL, 1996 / PG&E, 2004	DOE CRE Report 2016 / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996 / Distributor Web Sites / NCI Analysis, 2008	DOE CRE Report 2016 / Webstaurant 2022 / Guidehouse Analysis 2022										
Total Installed Cost (2022$)	ADL, 1996 / Distributor Web Sites / NCI Analysis, 2008	DOE CRE Report 2016 / Webstaurant 2022 / Guidehouse Analysis 2023										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	DOE CRE Report 2016 / Guidehouse Analysis 2022											
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources» Commercial Ice Machines

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Output (pounds [lbs] per day)	ADL, 1996 / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022 / CCMS Database 2022										
Water Use per Hundred Pounds (gal/hundred lbs)	ADL, 1996 / Distributor Web Sites	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022 / CCMS Database 2022										
Energy Use per Hundred Pounds (kWh/hundred lbs)	ADL, 1996 / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Annual Energy Use (kWh/y)	ACEEE, 2002 / NCI Analysis, 2012	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022 / ENERGY STAR										
Indexed Annual Efficiency	Calculated											
Average Life (years)	ADL, 1996 / Distributor Web Sites / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Retail Equipment Cost (2022$)	Distributor Web Sites / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Total Installed Cost (with Bin)	NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	ADL, 1996 / NCI Analysis, 2008	DOE, 2022: ACIM TSD / Guidehouse Analysis, 2022										
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources» Commercial Beverage Merchandisers

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE, 2014: CRE Report / Guidehouse Analysis 2022											
Size (ft^3)	ADL, 1996 / Distributor Web Sites	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Annual Energy Use (kWh/y)	ADL, 1996 / NCI Analysis, 2008	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / ENERGY STAR 2022										
Annual Energy Use / Volume ($kWh/ft^3/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Average Life (years)	ACEEE, 2002	DOE, 2014: CRE Report / Guidehouse Analysis 2022										
Retail Equipment Cost (2022$)	ADL, 1996 / Distributor Web Sites	DOE, 2014: CRE Report / Guidehouse Analysis 2022 / KaTom Restaurant Supply										
Total Installed Cost (2022$)	DOE, 2014: CRE Report / Guidehouse Analysis 2022											
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	DOE, 2014: CRE Report / Guidehouse Analysis 2022											
Annual Maintenance Cost (2022$/kBtu/h)	Calculated											

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Data Sources» Commercial Refrigerated Vending Machines

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
Cooling Capacity (Btu/h)	DOE, 2015: BVM TSD / Guidehouse Analysis, 2015	DOE, 2022: BVM TSD / Guidehouse Analysis, 2022										
Can Capacity	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Size (ft^3)	DOE, 2022: BVM TSD / Guidehouse Analysis, 2022											
Annual Energy Use (kWh/y)	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Annual Energy Use / Volume ($kWh/ft^3/y$)	Calculated											
Indexed Annual Efficiency	Calculated											
Average Life (years)	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Retail Equipment Cost (2022$)	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Total Installed Cost (2022$)	DOE, 2015: BVM TSD	DOE, 2022: BVM TSD										
Total Installed Cost (2022$/kBtu/h)	Calculated											
Annual Maintenance Cost (2022$)	DOE, 2015: BVM TSD / Guidehouse Analysis, 2015	DOE, 2022: BVM TSD / Guidehouse Analysis, 2022										
Annual Maintenance Cost (2022$/kBtu/h)	DOE, 2022: BVM TSD / Guidehouse Analysis, 2022											

Commercial Ventilation

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Data Sources» Commercial Constant Air Volume Ventilation

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
System Airflow (CFM)	CBECS 2003 & BED 2007	CBECS 2018										
System Fan Power (kW)	ASHRAE90.1-2007	ASHRAE90.1-2016	ASHRAE90.1-2019	ASHRAE90.1 2019 / Guidehouse Analysis 2022								
Specific Fan Power (W/CFM)												
Annual Fan Energy Use (kWh/y)												
Average Life (years)	ASHRAE: Service Life Database											
Total Installed Cost (2022$)	2022 RS Means Online											
Annual Maintenance Cost (2022$)	2022 RS Means Online / Guidehouse											
Total Installed Cost (2022$/thousand CFM)	Calculated											
Annual Maintenance Cost (2022$/thousand CFM)	Calculated											

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Data Sources» Commercial Variable Air Volume Ventilation

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
System Airflow (CFM)	CBECS 2003 & BED 2007	CBECS 2018										
System Fan Power (kW)	ASHRAE 90.1-2007	ASHRAE 90.1-2016	ASHRAE 90.1-2019	ASHRAE 90.1 2019 / Guidehouse Analysis 2022								
Specific Fan Power (W/CFM)												
Annual Fan Energy Use (kWh/y)												
Average Life (years)	ASHRAE: Service Life Database											
Total Installed Cost (2022$)	2022 RS Means Online											
Annual Maintenance Cost (2022$)	2022 RS Means Online / Guidehouse											
Total Installed Cost (2022$/thousand CFM)	Calculated											
Annual Maintenance Cost (2022$/thousand CFM)	Calculated											

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Data Sources» Commercial Fan Coil Unit

DATA SOURCES	2012	2018	2022				2030		2040		2050	
	Installed Stock Average	Installed Stock Average	Low	Typical	High	ENERGY STAR	Typical	High	Typical	High	Typical	High
System Airflow (CFM)	Product Literature											
System Fan Power (kW)	ASHRAE 90.1-2007	ASHRAE 90.1-2016	ASHRAE 90.1-2019	ASHRAE 90.1 2019 / Guidehouse Analysis 2022								
Specific Fan Power (W/CFM)												
Annual Fan Energy Use (kWh/y)												
Average Life (years)	ASHRAE: Service Life Database											
Total Installed Cost (2022$)	2022 RS Means Online											
Annual Maintenance Cost (2022$)	2022 RS Means Online / Guidehouse											
Total Installed Cost (2022$/thousand CFM)	Calculated											
Annual Maintenance Cost (2022$/thousand CFM)	Calculated											

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Appendix B
References

Guidehouse
1200 19th Street, NW, Suite 700
Washington, D.C. 20036

And

Leidos
11951 Freedom Drive
Reston, VA 20190

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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Gas General Activities Labor Expense
for the Years 2021 - 2024
($000,000)

Case No.: U-21806
Exhibit No.: A-134 (MJF-13)
Page: 1 of 1
Witness: MJFoster
Date: May 2025

Line No.	General Activities Labor Components	2021 Actual	2022 Actual	2023 Actual	2024 Actual
1	Senior Officer Expense	$ 0.7	$ 0.7	$ 0.7	$ 0.7
2	Capitalized Credits	(13.0)	(14.9)	(14.3)	(13.6)
3	Billing Credits	(0.6)	(1.0)	(0.9)	(0.4)
4	EICP included in General Activities Labor	0.2	7.7	7.8	9.1
5	Voluntary Separation Plan expense	-	4.0	12.6	-
6	Miscellaneous Expenses	0.5	1.9	1.5	1.4
7	**Total General Activities Labor Expense**	**$ (12.2)**	**$ (1.6)**	**$ 7.4**	**$ (2.8)**
8	**General Activities Labor Less VSP & EICP Expense; (Line 7 - Line 5 - Line 4)**	**$ (12.4)**	**$ (13.3)**	**$ (13.0)**	**$ (11.9)**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Compliance Program
Pipeline Integrity - TOD Capital and O&M Projects - 2023
Pipeline Integrity - Distribution (TOD)- Capital 2023 Costs by Project ID

Case No. U-21806
WP-MPG-13
Page 1 of 2

Portfolio	Assessment ID	Work Type	CAP Expenditure ($)	Internal Approval Y/N
Pipeline Integrity - TOD	Dx1002 - ROY	ECDA	(36,501)	Y
Pipeline Integrity - TOD	Dx1006 - Macomb	ECDA	497,207	Y
Pipeline Integrity - TOD	Dx1026 - Lansing	ECDA	309,601	Y
Pipeline Integrity - TOD	Dx1028 - Greenville	ECDA	380,869	Y
Pipeline Integrity - TOD	Dx1070 - Alma	ECDA	177,938	Y
Pipeline Integrity - TOD	Dx1071 - Alma	ECDA	214,491	Y
Pipeline Integrity - TOD	Dx1089 - Alma	ECDA	243,142	Y
Pipeline Integrity - TOD	Dx1090 - Saginaw	ECDA	207,411	Y
Pipeline Integrity - TOD	Dx1091 - Bad Axe	ECDA	163,603	Y
Pipeline Integrity - TOD	Dx1094 - Saginaw	ECDA	282,904	Y
Pipeline Integrity - TOD	Dx1002 - ROY	ICDA	83,620	Y
Pipeline Integrity - TOD	Dx1010 - Shelby	ICDA	117,599	Y
Pipeline Integrity - TOD	Dx1022 - Grand Ledge	ICDA	97,308	Y
Pipeline Integrity - TOD	Dx1024 - Williamston	ICDA	159,364	Y
Pipeline Integrity - TOD	Dx1027 - Lansing Turner	ICDA	399,119	Y
Pipeline Integrity - TOD	Dx1041 - Flint Lapeer	ICDA	221,017	Y
Pipeline Integrity - TOD	Dx1049 - Flint Torey	ICDA	259,792	Y
Pipeline Integrity - TOD	Dx1064 - Jackson Park	ICDA	(202,369)	Y
Pipeline Integrity - TOD	Dx1065 - Jackson Park	ICDA	253,783	Y
Pipeline Integrity - TOD	Dx1080 - Kalamazoo M Ave	ICDA	479,307	Y
Pipeline Integrity - TOD	Dx1082 - Kalamazoo M Ave	ICDA	716,659	Y
Pipeline Integrity - TOD	Dx1085 - Zilwaukee	ICDA	121,986	Y
Pipeline Integrity - TOD	Dx1087 - Zilwaukee	ICDA	530,377	Y
Pipeline Integrity - TOD	Dx1088 - Zilwaukee	ICDA	321,294	Y
Pipeline Integrity - TOD	Dx1090 - Akron	ICDA	533,705	Y
Pipeline Integrity - TOD	Dx1091 - Bad Axe	ICDA	55,936	Y
Pipeline Integrity - TOD	Dx1092 - Saginaw Dutch	ICDA	244,360	Y
Pipeline Integrity - TOD	Dx1094 - Saginaw Dutch	ICDA	254,548	Y
Pipeline Integrity - TOD	2022 Capital Tools-New Technicians	Project, pipeline repair / replacement	3,544	Y
Pipeline Integrity - TOD	2023 Capital Tools-New Technicians	Project, pipeline repair / replacement	218	Y
Pipeline Integrity - TOD	DAPP 18640 DX1085K 1of6 M13 at CodyEstey	Project, pipeline repair / replacement	1,577,894	Y
Pipeline Integrity - TOD	DAPP 18641 DX1085K CODY ESTEY @ 11 MILE	Project, pipeline repair / replacement	(62,933)	Y
Pipeline Integrity - TOD	DAPP 19038 LINE 1008 SECTION REPLACEMENT	Project, pipeline repair / replacement	342,063	Y
Pipeline Integrity - TOD	DAPP 19698 LINE 1022 CAPITOL AIRPORT	Project, pipeline repair / replacement	5,283	Y
Pipeline Integrity - TOD	DAPP 19963 LINE 1022 WAVERLY	Project, pipeline repair / replacement	(12,246)	Y
Pipeline Integrity - TOD	DAPP 20051 26" MAIN REPLACMENT MUE - Mar	Project, pipeline repair / replacement	140,441	Y
Pipeline Integrity - TOD	DAPP 21114 WAVERLY RD SAGINAW HWY HP	Project, pipeline repair / replacement	2,347,672	Y
Pipeline Integrity - TOD	LAN-DAPP 21114 Waverly Rd Saginaw Hwy	Project, pipeline repair / replacement	(2,204,420)	Y
Pipeline Integrity - TOD	LIV-DAPP11151 Mdlblt, Joy 10" HP Repl	Project, pipeline repair / replacement	48,035	Y
		Total	**9,273,622**	

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Compliance Program
Pipeline Integrity - TOD Capital and O&M Projects - 2023
Pipeline Integrity - Distribution (TOD) - O&M 2023 Costs by Project ID

Case No. U-21806
WP-MPG-13
Page 2 of 2

Portfolio	Assessment ID	Total O&M Expense ($)	HCA Digs O&M ($)	Non-HCA Digs O&M ($)	Internal Approval Y/N
Pipeline Integrity - TOD	Dx1006	51,036			Y
Pipeline Integrity - TOD	Dx1070, Dx1071, Dx1089 - Alma	3,057			Y
Pipeline Integrity - TOD	Dx1027	43,496	-	66,667	Y
Pipeline Integrity - TOD	Dx1028	111,196	52,196	59,000	Y
Pipeline Integrity - TOD	Dx1070	59,000	-	59,000	Y
Pipeline Integrity - TOD	Dx1071	102,496	-	102,496	Y
Pipeline Integrity - TOD	Dx1089	59,000	-	59,000	Y
Pipeline Integrity - TOD	Dx1090	41,601	26,098	15,504	Y
Pipeline Integrity - TOD	Dx1091	41,601	26,098	15,504	Y
Pipeline Integrity - TOD	Dx1094	102,496	-	102,496	Y
Pipeline Integrity - TOD	Dx1080	26,493			Y
Pipeline Integrity - TOD	gPIMS Annual Reads 2023 (Statewide)	21,688			Y
Pipeline Integrity - TOD	LIV Pipeline Integ IIS, Line 1099	3,980			Y
Pipeline Integrity - TOD	Pipeline Integrity 2022 Lab Cost	12,050			Y
Pipeline Integrity - TOD	Pipeline Integrity 2023 Lab Cost	7,933			Y
Pipeline Integrity - TOD	Pipeline Integrity Middle Material	5,298			Y
Pipeline Integrity - TOD	Dx1027	10,981			Y
Pipeline Integrity - TOD	Dx1028	11,114			Y
Pipeline Integrity - TOD	Dx1041	9,469			Y
Pipeline Integrity - TOD	Dx1080, Dx1082	9,131			Y
Pipeline Integrity - TOD	Dx1087	679			Y
Pipeline Integrity - TOD	Dx1090, Dx1091	7,654			Y
Pipeline Integrity - TOD	Dx1092, Dx1093, Dx1094	7,034			Y
Pipeline Integrity - TOD	Dx1094	829			Y
Pipeline Integrity - TOD	BSI EA 2014-(14, 17, & 18) Retrofit Upgr	23,973			Y
Pipeline Integrity - TOD	BSI EA UT 2020-1871 Repair	1,851			Y
Pipeline Integrity - TOD	DA Dept. TS Repair BSI EA 2390 & 2291	2,727			Y
Pipeline Integrity - TOD	UT Reads - Statewide	33,778			Y
	Total	**811,642**			

Business cases have not been conducted on these projects as the expenditures in the Pipeline Integrity Program represent the necessary inspections and remediation O&M expenses and capital expenditures that allow the Company to remain compliant with regulations mandated by the federal Pipeline & Hazardous Materials Safety Administration (“PHMSA”) and the Commission.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Compliance Program
Pipeline Integrity - TOD Capital and O&M Projects - 2024
Pipeline Integrity - Distribution (TOD)- CAP 2024 Costs by Project ID

Portfolio	Assessment ID	Work Type	HCA Assessments ECDA ($)	Non-HCA/MCA Assessments ($)	Casing Assessments ($)	CAP Expenditure ($)	Internal Approval Y/N
Pipeline Integrity - TOD	Dx1015	ECDA Digs	174,653				Y
Pipeline Integrity - TOD	Dx1020	ECDA Digs	174,653				Y
Pipeline Integrity - TOD	Dx1049	ECDA Digs	529,791	387,058			Y
Pipeline Integrity - TOD	Dx1080	ECDA Digs	174,653				Y
Pipeline Integrity - TOD	Dx1080-Class	ECDA Digs	225,387	175,275			Y
Pipeline Integrity - TOD	Dx1099	ECDA Digs	326,855				Y
	ECDA Total		**1,605,992**	**562,333**	**178,444**	**2,346,768**	

			HCA Assessments ICDA ($)	Non-HCA/MCA Assessments ($)			
Pipeline Integrity - TOD	AlmaCG_Dx1070_Downstream of Dx1071	ICDA Digs	160,206				Y
Pipeline Integrity - TOD	AlmaCG_Dx1071_Mainline	ICDA Digs	240,308	523,531			Y
Pipeline Integrity - TOD	AlmaCG_Dx1089_Mainline	ICDA Digs	320,411				Y
Pipeline Integrity - TOD	GreenfieldCG_Dx1020_Mainline	ICDA Digs	213,607	579,609			Y
Pipeline Integrity - TOD	LahserCG_Dx1020_Mainline	ICDA Digs	213,607				Y
Pipeline Integrity - TOD	MtPleasantCG_Dx1070_Mainline	ICDA Digs	213,607				Y
Pipeline Integrity - TOD	NorthLyonCG_Dx1099_Mainline	ICDA Digs	213,607				Y
Pipeline Integrity - TOD	RedRunCG_Dx1002f West_Mainline	ICDA Digs	320,411				Y
Pipeline Integrity - TOD	RedRunCG_Dx1002g_Mainline	ICDA Digs	293,710				Y
Pipeline Integrity - TOD	RedRunCG_Dx1006_Downstream of Dx1002f West	ICDA Digs	160,206				Y
Pipeline Integrity - TOD	RedRunCG_Dx1008_Downstream of 1002f West	ICDA Digs	160,206				Y
Pipeline Integrity - TOD	RedRunCG_Dx1009_Downstream of 1002f West	ICDA Digs	160,206				Y
	ICDA Total		**2,670,092**	**1,103,140**		**3,773,232**	
	Total					**6,120,000**	

Portfolio	Assessment ID	Work Type	DA Survey O&M ($)	HCA Digs O&M ($)	Non-HCA Digs O&M ($)	Total O&M Expense ($)	Internal Approval Y/N
Pipeline Integrity - TOD	Dx1015	ECDA Digs	35,614	-	70,735		Y
Pipeline Integrity - TOD	Dx1020	ECDA Digs	35,614	70,735	-		Y
Pipeline Integrity - TOD	Dx1049	ECDA Digs	47,598	-	85,387		Y
Pipeline Integrity - TOD	Dx1080	ECDA Digs	59,583	141,469	141,469		Y
Pipeline Integrity - TOD	Dx1080-Class	ECDA Digs	47,598	56,588	141,469		Y
Pipeline Integrity - TOD	Dx1099	ECDA Digs	35,614	70,735	-		Y
	ECDA Total		**261,621**	**339,526**		**601,147**	
Pipeline Integrity - TOD	AlmaCG_Dx1070_Downstream of Dx1071	ICDA Digs	35,611				Y
Pipeline Integrity - TOD	AlmaCG_Dx1071_Mainline	ICDA Digs	20,326				Y
Pipeline Integrity - TOD	AlmaCG_Dx1089_Mainline	ICDA Digs	20,326				Y
Pipeline Integrity - TOD	GreenfieldCG_Dx1020_Mainline	ICDA Digs	20,326				Y
Pipeline Integrity - TOD	LahserCG_Dx1020_Mainline	ICDA Digs	20,326				Y
Pipeline Integrity - TOD	MtPleasantCG_Dx1070_Mainline	ICDA Digs	20,326				Y
Pipeline Integrity - TOD	NorthLyonCG_Dx1099_Mainline	ICDA Digs	35,613				Y
Pipeline Integrity - TOD	RedRunCG_Dx1002f West_Mainline	ICDA Digs	47,598				Y
Pipeline Integrity - TOD	RedRunCG_Dx1002g_Mainline	ICDA Digs	35,614				Y
Pipeline Integrity - TOD	RedRunCG_Dx1006_Downstream of Dx1002f West	ICDA Digs	59,583				Y
Pipeline Integrity - TOD	RedRunCG_Dx1008_Downstream of 1002f West	ICDA Digs	35,614				Y
Pipeline Integrity - TOD	RedRunCG_Dx1009_Downstream of 1002f West	ICDA Digs	35,614				Y
	ICDA Total		**386,876**			**386,876**	
Pipeline Integrity - TOD		UT Sensor Data	**70,735**			**70,735**	Y
		Total				**1,058,758**	

Business cases have not been conducted on these projects as the expenditures in the Pipeline Integrity Program represent the necessary inspections and remediation O&M expenses and capital expenditures that allow the Company to remain compliant with regulations mandated by the federal Pipeline & Hazardous Materials Safety Administration ("PHMSA") and the Commission.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Regulatory Compliance Program
Pipeline Integrity - TOD Capital and O&M Projects - 2025
Pipeline Integrity - Distribution (TOD)- CAP 2025 Costs by Project ID

Case No. U-21806
WP-MPG-17
Page 1 of 1

Portfolio	Assessment ID	Work Type	CAP Expenditure ($)	Internal Approval Y/N
Pipeline Integrity - TOD	Casings	Casings	2,000,000	Y
Pipeline Integrity - TOD	Risk Mitigation	Risk Mitigation	661,167	Y
Pipeline Integrity - TOD	Dx1002MAC	TOD ECDA	368,000	Y
Pipeline Integrity - TOD	Dx1087	TOD ECDA	184,000	Y
Pipeline Integrity - TOD	Dx1088	TOD ECDA	368,000	Y
Pipeline Integrity - TOD	Dx1088-192710	TOD ECDA	414,000	Y
Pipeline Integrity - TOD	Dx1092	TOD ECDA	138,000	Y
Pipeline Integrity - TOD	Dx1092-192710	TOD ECDA	92,000	Y
Pipeline Integrity - TOD	Dx1093	TOD ECDA	138,000	Y
Pipeline Integrity - TOD	ICDA Digs	TOD ICDA	3,000,000	Y
Pipeline Integrity - TOD	Tool Program	Tool Program	50,000	Y
TOTAL EXPENDITURE			**7,413,167**	

Pipeline Integrity - Distribution (TOD) - O&M 2025 Costs by Project ID

Portfolio	Assessment ID	Work Type	O&M Expense ($)	
Pipeline Integrity - TOD	Dx1008	DA Survey	62,016	Y
Pipeline Integrity - TOD	Dx1014	DA Survey	47,923	Y
Pipeline Integrity - TOD	Dx1022	DA Survey	56,099	Y
Pipeline Integrity - TOD	Dx1022-192710	DA Survey	67,656	Y
Pipeline Integrity - TOD	Dx1085	DA Survey	8,662	Y
Pipeline Integrity - TOD	Dx1008	DA Survey Risk	763	Y
Pipeline Integrity - TOD	Dx1014	DA Survey Risk	5,167	Y
Pipeline Integrity - TOD	Dx1022	DA Survey Risk	99,129	Y
Pipeline Integrity - TOD	Dx1022-192710	DA Survey Risk	40,040	Y
Pipeline Integrity - TOD	Dx1085	DA Survey Risk	120,362	Y
Pipeline Integrity - TOD	Dx1002MAC	TOD ECDA	69,890	Y
Pipeline Integrity - TOD	Dx1087	TOD ECDA	34,945	Y
Pipeline Integrity - TOD	Dx1088	TOD ECDA	69,890	Y
Pipeline Integrity - TOD	Dx1088-192710	TOD ECDA	69,890	Y
Pipeline Integrity - TOD	Dx1092	TOD ECDA	34,945	Y
Pipeline Integrity - TOD	Dx1092-192710	TOD ECDA	34,945	Y
Pipeline Integrity - TOD	Dx1093	TOD ECDA	34,945	Y
Pipeline Integrity - TOD	Tool Program	Tool Program	37,984	Y
Pipeline Integrity - TOD	UT Program	UT Program	189,918	Y
TOTAL EXPENSE			**1,085,169**	

Business cases have not been conducted on these projects as the expenditures in the Pipeline Integrity Program represent the necessary inspections and remediation O&M expenses and capital expenditures that allow the Company to remain compliant with regulations mandated by the federal Pipeline & Hazardous Materials Safety Administration (“PHMSA”) and the Commission.

MICHIGAN PUBLIC SERVICE COMMISSION Case No. U-21806
Consumers Energy Company WP-MPG-19
Regulatory Compliance Program Page 1 of 1
Pipeline Integrity - TOD Capital and O&M Projects - 2026
Pipeline Integrity - Distribution (TOD)- CAP 2026 Costs by Project ID

Portfolio	Assessment ID	Work Type	CAP Expenditure ($)	Internal Approval Y/N
Pipeline Integrity - TOD	Casings	Casings	2,000,000	Y
Pipeline Integrity - TOD	Risk Mitigation	Risk Mitigation	4,865,585	Y
Pipeline Integrity - TOD	Dx1008	TOD ECDA	230,000	Y
Pipeline Integrity - TOD	Dx1014	TOD ECDA	184,000	Y
Pipeline Integrity - TOD	Dx1022	TOD ECDA	184,000	Y
Pipeline Integrity - TOD	Dx1022-192710	TOD ECDA	230,000	Y
Pipeline Integrity - TOD	Dx1085	TOD ECDA	46,000	Y
Pipeline Integrity - TOD	ICDA Digs	TOD ICDA	3,000,000	Y
Pipeline Integrity - TOD	Tool Program	Tool Program	100,000	Y
TOTAL EXPENDITURE			**10,839,585**	

Pipeline Integrity - Distribution (TOD) - O&M 2026 Costs by Project ID

Portfolio	Assessment ID	Work Type	O&M Expense ($)	
Pipeline Integrity - TOD	Dx1009	DA Survey	150,773	Y
Pipeline Integrity - TOD	Dx1019	DA Survey	257,197	Y
Pipeline Integrity - TOD	Dx1019-192710	DA Survey	60,736	Y
Pipeline Integrity - TOD	Dx1024	DA Survey	119,115	Y
Pipeline Integrity - TOD	Dx1041	DA Survey	22,011	Y
Pipeline Integrity - TOD	Dx1062	DA Survey	23,407	Y
Pipeline Integrity - TOD	Dx1064	DA Survey	19,147	Y
Pipeline Integrity - TOD	Dx1065	DA Survey	26,743	Y
Pipeline Integrity - TOD	Dx1082	DA Survey	124,690	Y
Pipeline Integrity - TOD	Dx1019	DA Survey Risk	2,534	Y
Pipeline Integrity - TOD	Dx1019-192710	DA Survey Risk	68,769	Y
Pipeline Integrity - TOD	Dx1024	DA Survey Risk	6,825	Y
Pipeline Integrity - TOD	Dx1041	DA Survey Risk	23,911	Y
Pipeline Integrity - TOD	Dx1064	DA Survey Risk	11,961	Y
Pipeline Integrity - TOD	Dx1065	DA Survey Risk	1,190	Y
Pipeline Integrity - TOD	Dx1082	DA Survey Risk	9,153	Y
Pipeline Integrity - TOD	Dx1082-192710	DA Survey Risk	41,148	Y
Pipeline Integrity - TOD	Dx1008	TOD ECDA	46,772	Y
Pipeline Integrity - TOD	Dx1014	TOD ECDA	46,772	Y
Pipeline Integrity - TOD	Dx1022	TOD ECDA	46,772	Y
Pipeline Integrity - TOD	Dx1022-192710	TOD ECDA	46,772	Y
Pipeline Integrity - TOD	Tool Program	Tool Program	50,839	Y
Pipeline Integrity - TOD	UT Program	UT Program	254,193	Y
TOTAL EXPENSE			**1,461,430**	

Business cases have not been conducted on these projects as the expenditures in the Pipeline Integrity Program represent the necessary inspections and remediation O&M expenses and capital expenditures that allow the Company to remain compliant with regulations mandated by the federal Pipeline & Hazardous Materials Safety Administration ("PHMSA") and the Commission.

MPSC Case No.	**U-21806**
Responding Party:	Attorney General
Respondent:	Sebastian Coppola
Requestor:	CECo
Question No.:	**2-CE-AG-4**

2-CE-AG-4
The following question pertains to the Company's Pipeline Integrity TOD program, specifically casing assessments. On page 61, beginning on line 6, through page 61, line 8 of his direct testimony, Mr. Coppola states "In response to additional discovery, the Company stated that is has very limited experience with the cost of inspecting and remediating casings." Please provide the specific discovery response and location where the Company made this statement.

Response:

Assuming the reference is to page 62 of Mr. Coppola's direct testimony, that section of the testimony should have been a conclusion reached by Mr. Coppola and not a direct statement attributed to the Company. Mr. Coppola reached his conclusion that the Company had very limited experience with the cost of inspecting and remediating casings based on the following information provided by the Company in response to discovery:

a. AG-CE-0329b: The two casings are scheduled to be inspected using a robotic ILI tool in August of 2025. After the inspection, the condition of the pipe inside the casing will be determined and remediation performed if required.

b. AG-CE-0329e: There weren't any similar casing projects performed in 2022, 2023 or 2024. Casings are assessed every 6 to 7 years.

c. AG-CE-0329f. Currently these casing[s] are in the planning and scheduling phase. The ILI tool vendor is being scheduled along with construction crews to perform excavation and construction.

DR AG-CE-0329 is included in Exhibit AG-15.

Date: 5/2/2025

U21806-CUB-CE-0248
Page **1** of **1**

Question:

30. Refer to Griffin, p. 23, which discusses the Corrosion Control – Transmission O&M Program. Please provide, for 2023-2026, the number of special projects and average cost per project to be completed for each project type listed by Griffin in this category: large atmospheric painting, pipeline recoating, shorted casing remediation, close internal survey.

Response:

The table below shows a breakdown of project types by year for each category.

	2023 Actual			2024 Preliminary Actual			2025 Projection			2026 Projection		
	Units	Avg Cost	Total	Units	Avg Cost	Total	Units	Avg Cost	Total	Units	Avg Cost	Total
Atmospheric Painting (projects)	7	$56,118	$392,825	8	$81,644	$653,155	8	$81,875	$655,000	8	$82,727	$910,000
Pipeline Recoating (feet)	300	$949	$284,634	790	$387	$305,784	2500	$400	$1,000,000	2500	$400	$1,000,000
Shorted casing/Test Stations (projects)	7	$11,704	$81,925	19	$1,702	$32,335	10	$10,000	$100,000	10	$10,000	$100,000
Close Interval survey (miles)	95	$1,975	$187,616	90	$1,972	$177,473	100	$2,000	$200,000	100	$2000	$200,000
Total			$947,000			$1,168,747			$1,955,000			$2,210,000

As stated in my direct testimony, much of the work performed in this program is typically identified in yearly surveys and remediated in a short timeframe.

For atmospheric painting, the annual variations in average cost for projects is due to the nature and size of the projects. This work is typically large painting projects at compressor stations, city gates or valve sites. It may be a portion of the facility (a couple of components of varying size pipe) or the entire facility. The survey for the atmospheric inspection is performed on a 3-year basis. The increase in cost in 2026 is based on doing larger projects since smaller projects were completed in 2023.

Pipeline recoating also has several variables that make establishing a unit cost difficult. The units shown here are in feet, but the pipe diameter plays a significant role as well in determining the final cost. This work consists of excavating the pipe, removing old coating and applying new coating. A large, 26" diameter pipe, will have a larger cost per foot to recoat than a 10" pipe. For the 2024 work, a large project on Line 1200A was identified for recoat and much of the money spent in this category was to recoat this pipeline.

The shorted casings/test station work is a conglomeration of various types of work that include excavating the pipe, inspecting the pipe and installation of test stations to perform future monitoring. Due to the varying nature and complexity of the work, the unit cost can vary as seen between 2023 and 2024. In 2023, more casing investigation work was done, which typically requires deep excavations approximately 10 feet deep. In 2024, more test station work was performed on pipe at more typical/shallower depths.

Witness: MICHAEL P. GRIFFIN
Date: February 26, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
Exhibit No.: A-138 (KAP-8)
Page: 1 of 3
Witness: KAPascarello
Date: May 2025

U21806-AG-CE-0431_Pascarello_Attachment_1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
Exhibit No.: A-84 (KAP-6)
Page: 1 of 3
Witness: KAPascarello
Date: December 2024

Line #		Company Regions			
		Southwest (SW)	Northeast (NE)	Southeast (SE)	Total
	Company Costs:				
1	**2023 Actual Total [(1)]**				
2	Total Services Renewal, Retired Tie-overs	1,358	3,322	3,969	8,649
3	**Miles Main Installed**	**17.35**	**55.12**	**36.47**	**108.9**
4	Total Service/Miles	78	60	109	79
5	Project Cost ($M)	$40.7	$79.8	$56.1	$176.6
6	Carry-Over & Future Year ($M)	$1.0	$2.4	$1.9	$5.4
7	**Total Cost ($(Million)**	**$41.7**	**$82.2**	**$58.0**	**$181.9**
8	**Cost per Mile**	**$ 2,402,397**	**$ 1,492,154**	**$ 1,590,322**	**$ 1,669,978**
9	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**				$ 3,550,319
10	**2023 Total EIRP Program and Facilities capital expenditures**				**$ 181,930,182**
11					
12	**2024 Projected Total**				
13	Total Services Renewal, Retired Tie-overs	2,150	4,426	5,538	12,114
14	**Miles Main Installed**	**43.64**	**42.44**	**48.56**	**134.6**
15	Total Service/Miles	49	104	114	90
16	Project Cost ($M)	$61.8	$58.7	$70.1	$190.6
17	Carry-Over & Future Year ($M)	$1.1	$2.3	$1.7	$5.0
18	**Total Cost ($(Million)**	**$62.8**	**$60.9**	**$71.8**	**$195.6**
19	**Cost per Mile**	**$ 1,440,092**	**$ 1,435,338**	**$ 1,479,113**	**$ 1,452,667**
20	**EIRP Facilities (expenditures shown in Facilities Exhibit A-70 (QAG-3)**				**$ 6,088,574**
21	**2023 Total EIRP Program and Facilities capital expenditures**				**$ 201,675,656**
11					
12	**2024 Preliminary Actual**				
13	Total Services Renewal, Retired Tie-overs	2,079	4,094	4,772	10,945
14	**Miles Main Installed**	**41.82**	**41.36**	**44.25**	**127.4**
15	Total Service/Miles	50	99	108	86
16	Project Cost ($M)	$62.5	$57.4	$67.9	$187.8
17	Carry-Over & Future Year ($M)	$1.1	$2.3	$1.7	$5.1
18	**Total Cost ($(Million)**	**$63.6**	**$59.7**	**$69.6**	**$193.0**
19	**Cost per Mile**	**$ 1,521,528**	**$ 1,443,915**	**$ 1,573,229**	**$ 1,514,287**
20	**EIRP Facilities (expenditures shown in Facilities Exhibit A-70 (QAG-3)**				**$ 5,844,204**
21	**2023 Total EIRP Program and Facilities capital expenditures**				**$ 198,817,961**
22					
23	**2025 Projected Total**				
24	Total Services Renewal, Retired Tie-overs	2,588	2,689	7,251	12,528
25	**Miles Main Installed**	**30.32**	**52.19**	**59.47**	**142.0**
26	Total Service/Miles	85	52	122	88
27	Project Cost ($M)	$50.8	$110.8	$83.6	$245.3
28	Carry-Over & Future Year ($M)	$1.0	$2.1	$1.9	$5.0
29	**Total Cost ($(Million)**	**$51.8**	**$112.9**	**$85.5**	**$250.3**
30	**Cost per Mile**	**$ 1,709,238**	**$ 2,163,624**	**$ 1,438,423**	**$ 1,762,831**
31					
32	**2026 Projected Total**				
33	Total Services Renewal, Retired Tie-overs	1,320	4,126	6,457	11,903
34	**Miles Main Installed**	**30.89**	**57.47**	**61.96**	**150.3**
35	Total Service/Miles	43	72	104	79
36	Project Cost ($M)	$68.5	$88.0	$90.1	$246.6
37	Carry-Over & Future Year ($M)	$1.0	$2.1	$1.9	$5.0
38	**Total Cost ($(Million)**	**$69.5**	**$90.1**	**$92.0**	**$251.6**
39	**Cost per Mile**	**$ 2,249,156**	**$ 1,568,140**	**$ 1,484,958**	**$ 1,673,806**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
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Date: December 2024

		Company Regions			
		Southwest (SW)	Northeast (NE)	Southeast (SE)	
40	**2023 actual capital expeditures [1]:**				
41	2023 Actual Cost Per Mile - Plastic	$ 2,343,464	$ 1,434,706	$ 1,537,740	**$ 1,625,519**
42	Number of Miles of Main - Plastic	17.3	48.5	36.5	102.3
43	2023 Preliminary Actual EIRP Costs - Plastic	$40,655,999	$69,578,082	$56,088,205	$166,322,286
44	TOD Project (ALM3) (6.62miles)		$10,230,205		$10,230,205
45	Carry-Over & Future Year ($M)				$5,374,140
46	2023 Preliminary Actual EIRP Capital Expenditures				**$181,926,631**
47	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**)				$ 3,550,319
48	**2023 actual total EIRP Program and Facilities capital expenditures**				**$ 185,476,950**
49					
50	**2024 projected capital expeditures:**				
51	2024 Forecasted Cost Per Mile - Plastic	$ 1,306,077	$ 1,382,187	$ 1,365,542	**$ 1,353,912**
52	Number of Miles of Main - Plastic	36.6	42.4	47.4	126.4
53	2024 Forecasted EIRP Costs - Plastic	$47,802,418	$58,660,016	$64,672,069	$171,134,504
54	TOD/HP Steel Projects - 8.24 miles	$13,965,551	$0	$5,473,207	$19,438,758
55	Carry-Over & Future Year ($M)	$1,077,625	$2,255,727	$1,680,468	$5,013,820
56	2024 Projected EIRP Capital Expenditures				**$195,587,082**
57	**Projected 10 month ending October 31, 2024**				**$ 172,399,356**
58	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**)				$ 6,088,574
59	**2024 forecasted total EIRP Program and Facilities capital expenditures**				**$ 201,675,656**
49					
50	**2024 preliminary actual capital expeditures:**				
51	2024 Forecasted Cost Per Mile - Plastic	$ 1,388,892	$ 1,387,892	$ 1,445,297	**$ 1,408,956**
52	Number of Miles of Main - Plastic	34.5	41.4	43.0	119.0
53	2024 Forecasted EIRP Costs - Plastic	$47,980,701	$57,409,031	$62,218,122	$167,607,855
54	TOD/HP Steel Projects - 8.48 miles	$14,558,357	$0	$5,681,335	$20,239,692
55	Carry-Over & Future Year ($M)	$1,096,828	$2,317,346	$1,712,035	$5,126,210
56	2024 Projected EIRP Capital Expenditures				**$192,973,757**
57	**Preliminary Actual 10 month ending October 31, 2024**				**$ 173,397,304**
58	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**)				$ 5,844,204
59	**2024 Preliminary Actual total EIRP Program and Facilities capital expenditures**				**$ 198,817,961**
60					
61	**2025 projected capital expeditures (Corrected) [2]:**				
62	2025 Forecasted Cost Per Mile - Plastic	$ 1,306,077	$ 1,382,187	$ 1,365,542	**$ 1,357,311**
63	Number of Miles of Main - Plastic	25.8	33.8	58.5	118.1
64	2025 Forecasted EIRP Costs - Plastic	$33,719,049	$46,752,317	$79,847,224	$160,318,590
65	TOD/HP Steel Projects - 21.5 miles	$17,100,000	$60,800,000	$3,800,000	$81,700,000
66	Carry-Over & Future Year ($M)	$1,000,000	$2,100,000	$1,900,000	$5,000,000
67	2025 Projected EIRP Capital Expenditures				**$247,018,590**
68	**Projected 10 month ending October 31, 2025**				**$ 204,611,703**
69	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**				$ -
70	**2025 forecasted total EIRP Program and Facilities capital expenditures**				**$ 247,018,590**
71					
72	**2026 projected capital expeditures:**				
73	2026 Forecasted Cost Per Mile - Plastic	$ 1,345,259	$ 1,423,653	$ 1,406,508	**$ 1,404,251**
74	Number of Miles of Main - Plastic	20.4	55.0	60.9	136.2
75	2026 Forecasted EIRP Costs - Plastic	$27,457,048	$78,265,841	$85,597,258	$191,320,148
76	TOD/HP Steel Projects - 14.1 miles	$41,019,906	$9,747,936	$4,507,772	$55,275,613
77	Carry-Over & Future Year ($M)	$1,000,000	$2,100,000	$1,900,000	$5,000,000
78	2026 Projected EIRP Capital Expenditures				**$ 251,595,761**
79	**Projected 12 month ending October 31, 2026**				**$ 250,809,975**
80	EIRP Facilities (expenditures shown in Facilities **Exhibit A-70 (QAG-3)**				$ -
81	**2026 forecasted total EIRP Program and Facilities capital expenditures**				**$ 251,595,761**

[1] Reference: 2023 EIRP Annual Performance Report filing U-21308

[2] Highlighted sections are corrected miles and projected expenditures due to a feet to miles conversion error for the BCY2 project

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
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MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Detailed Summary of Actual & Projected Capital Expenses
Enhanced Infrastructure Replacement Program
($000)

Case No.: U-21806
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Page: 3 of 3
Witness: KAPascarello
Date: December 2024

		Company Regions			
Line #		Southwest (SW)	Northeast (NE)	Southeast (SE)	Total
	Company Costs:				
1	**2018 Actual Total**				
2	Total Services Renewal, Retired Tie-overs	649	1,411	2,563	4,623
3	**Miles Main Installed**	**13.26**	**15.20**	**24.37**	**52.8**
4	Total Service/Miles	49	93	105	88
5	Project Cost ($M)	$34.7	$12.7	$37.3	$84.6
6	Carry-Over & Future Year ($M)	$.9	$.3	$1.0	$2.2
7	**Total Cost ($(Million)**	**$35.6**	**$13.0**	**$38.2**	**$86.8**
8	**Cost per Mile**	**$ 2,684,825**	**$ 853,844**	**$ 1,567,901**	**$ 1,642,797**
9					
10	**2019 Actual Total**				
11	Total Services Renewal, Retired Tie-overs	643	1,087	3,192	4,922
12	**Miles Main Installed**	**8.86**	**11.30**	**30.57**	**50.7**
13	Total Service/Miles	73	96	104	97
14	Project Cost ($M)	$12.7	$12.6	$48.2	$73.5
15	Carry-Over & Future Year ($M)	$.9	$.8	$3.2	$4.9
16	**Total Cost ($(Million)**	**$13.5**	**$13.4**	**$51.5**	**$78.4**
17	**Cost per Mile**	**$ 1,527,539**	**$ 1,185,190**	**$ 1,683,162**	**$ 1,545,060**
18					
19	**2020 Actual Total**				
20	Total Services Renewal, Retired Tie-overs	641	1,500	6,373	8,514
21	**Miles Main Installed**	**10.22**	**15.50**	**45.55**	**71.3**
22	Total Service/Miles	63	97	140	119
23	Project Cost ($M)	$15.2	$21.9	$76.9	$114.0
24	Carry-Over & Future Year ($M)	$.6	$.9	$3.0	$4.5
25	**Total Cost ($(Million)**	**$15.8**	**$22.8**	**$80.0**	**$118.5**
26	**Cost per Mile**	**$ 1,544,687**	**$ 1,470,051**	**$ 1,755,749**	**$ 1,663,349**
27					
28	**2021 Actual Total**				
29	Total Services Renewal, Retired Tie-overs	5,000	3,794	5,014	13,808
30	**Miles Main Installed**	**68.94**	**45.53**	**42.70**	**157.2**
31	Total Service/Miles	73	83	117	88
32	Project Cost ($M)	$72.0	$86.2	$67.9	$226.1
33	Carry-Over & Future Year ($M)	$.3	$1.9	$2.5	$4.7
34	**Total Cost ($(Million)**	**$72.3**	**$88.1**	**$70.4**	**$230.8**
35	**Cost per Mile**	**$ 1,048,660**	**$ 1,934,649**	**$ 1,648,117**	**$ 1,468,180**
36					
37	**2022 Actual Total**				
38	Total Services Renewal, Retired Tie-overs	3,622	4,327	6,125	14,074
39	**Miles Main Installed**	**51.40**	**66.10**	**44.60**	**162.1**
40	Total Service/Miles	70	65	137	87
41	Project Cost ($M)	$58.9	$92.9	$76.5	$228.4
42	Carry-Over & Future Year ($M)	$6.3	$5.7	$7.7	$19.8
43	**Total Cost ($(Million)**	**$65.3**	**$98.6**	**$84.3**	**$248.1**
44	**Cost per Mile**	**$ 1,269,571**	**$ 1,491,824**	**$ 1,889,774**	**$ 1,530,842**

(1) Reference: EIRP Annual Performance Report filing for each year

U21806-AG-CE-0426
Page **1** of **2**

Question:

139. Refer to page 82 of Ms. Pascarello's direct testimony on the Damage Prevention and MISS DIG software purchase. Please:
a. Explain how the new software will prevent damage to gas facilities.
b. Explain how the additional features, such as photo AI and augmented reality, work and how they will ensure safety.
c. If the $1.6 million is for a five-year subscription, is the Company capitalizing the $954,000 for the gas business or establishing a deferred debit and amortizing 1/5th to O&M expense each year? Explain why.

Response:

a. This software assists in preventing damages and reduce public safety risk through the following:

- Utilized as a ticket management solution which enables visibility into contractor and internal staking and locating performance data and as a backup work management solution if supplemental support is needed. The solution provides ticket execution performance analytics and reporting to ensure compliance with PA 174. This enables PA 174 required positive response to MISS DIG ticket requests.
- Provides analytics, reporting, and risk scoring to enable efficient and effective proactive field interventions supporting coaching and training of 3rd party excavators and associated performance and workload management capabilities. Solution enables automated workflows integrated with Damage Prevention programs and public awareness communications.

b. Additional capabilities supporting reducing damages and public safety risk include:

- AI – determines likelihood and impact of any incident that may occur to Company facilities through utilization of photo AI quality assurance audit processes to identify staking and locating anomalies that enables more rapid risk mitigation while utilizing machine learning for continuous improvement.
- Augmented reality will enable users to view underground assets onsite with support of site walks and quality assurance audit use cases.

c. At the time of filing this case, the Company projected $954,000 in capital expenditures for this software purchase based on the new functionality offered. The Company has now determined that only a portion of the software cost will be capitalized. The gas portion of the software cost has been reduced to a total of $829,082, with $195,000 as capital and $634,082 as O&M. This change will reduce the capital test year amount shown in Exhibit A-83 (KAP-5), line 4, from $4,168,000 to $3,409,000 and increase the O&M test year amount shown in Exhibit A-81 (KAP-2), line 12, from

$1,231,000 to $1,865,082. The entire subscription cost will occur in the test year of this case. The Company is not establishing a deferred debit or amortizing 1/5 to O&M.

Witness: Kristine A. Pascarello
Date: March 12, 2025

U21806-SA-CE-388
Requested By: Cindy L. Creisher (CLC-10)
Respondent: Kristine A. Pascarello
Date of Response: 3/18/2025
Page **1** of **1**

Question:

With reference to the direct testimony of Witness Kristine Pascarello on page 55, lines 1-7, provide a list of segments of wrought iron pipe that includes the length, location, and projected cost of replacement by year for the replacement work that is planned to be completed in 2025 and 2026. The projected replacement costs should include detail of capital expenditures that are projected to fall within the 12 months ending October 31, 2026.

Response:

The Material Condition Non-Modeled program plans to replace 7.64 miles of the remaining 12 miles of wrought iron. The remainder of the 12 miles are included in the 2026 EIRP KAL11 Bangor project. The replacement plan by year with related miles and capital expenditures planned in Material Condition Non-Modeled is:

Year	Miles Replaced	Location/Approx. Length	$
2025	1.3	Lawton: 4,499 ft Hartford: 1,905 ft	$1,500,000.00
2026	4.5	Several small pipe segments of various footage in Comstock, Schoolcraft, Vicksburg, Parchment, Paw Paw, and Galesburg totaling 4.5 miles	$5,000,000.00

To avoid construction during the heating season, projects are planned to for April through October, so the entire 2026 projection of $5 million will fall within the 12 months ending October 31, 2026.

U21806-MNSC-CE-0075_Pascarello_Attachment_2

Parent Project Number (PPN)	DAPP #	Pipe Pressure	Headquarters	Project Location	Project Name	Total Vintage Retired	Cast Iron	Coated & Wrapped (C&W)	Bare Steel (BS)	Threaded & Coupled (T&C)	Wrought Iron	Plastic	Code 3 (Ft)	Install Plastic	Install Steel	Construct	Risk Rank	Selection Reason
PPN4104SWJAC	21975	MP - Plastic	SW - Lansing/ Jackson	Tecumseh	JAC1 (Tecumseh)	2,491	-	94	2,453	38	-	74	-	2,375	-	CE	#5 SP/MP Segments	1950 Bare Steel, T&C MP Pipe that was risk ranked #5 for SP/MP Segments. This pipe was within SP/MP Grid #55
PPN4108NESAG	30153	HP - Steel	NE - Saginaw	Saginaw	SAG9 MP (Ph. 2)		-	-	2,474	-	-	-	-	1,800	-	CE	*added to Phase 1 of SAG9*	Two large county drains in the area of the HP work in Phase 1, so we decided to add this MP work to avoid HP services crossing these drains and add MP pipe and services.
PPN4122NESAG	20193	HP - Steel	NE - Saginaw	Saginaw	SAG6 TOD Line 1087G (TOD)	24,799	-	647	24,799	-	-	-	250	-	35,000	Contractor	TOD	1933 Bare steel 10" HP Pipe operating at >20% SMYS. Originally planned for 2024 but was rolled into plan for 2025. This is the #4 risk ranked TOD pipe segment. Moving this pipe from the RR ROW was an additional benefit into the road ROW.
PPN4109NESAG	21770	HP - Steel	NE - Saginaw	Saginaw	SAG8 (Junction Rd HP)	22,113	-	360	22,113	-	-	6	-	-	13,700	CE	#2 HP	1950 Bare Steel 6" HP Pipe that was risk ranked #2 for HP Segments
PPN4108NESAG	21771	HP - Steel	NE - Saginaw	Saginaw	SAG9 Ph 1 (Shields HP)	2,474	-	-	2,474	-	-	-	-	-	2,410	CE	#3 HP	1933 Bare Steel 10" HP Pipe that was risk ranked #3 for HP Segments. Additionally we added some MP pipe to remove some customer HP Stands.
PPN4094NESAG	21768,9	SP - Plastic	NE - Saginaw	Saginaw	SAG11 (Ph. 1,2)	8,337	3,758	2,489	2,090	-	-	-	-	11,372	-	CE	#3 SP/MP Segments	1960 Bare Steel 12" SP Pipe and 1940 Cast Iron 2", 4", 6" SP Pipe that was risk ranked #3 for MP Segments. Additionally we will be converting ~8,000' of SP plastic pipe to MP plastic pipe. This pipe is within SP/MP Grids #4, #127, #309
PPN4127NESAG	22650,1	SP - Plastic	NE - Saginaw	Saginaw	SAG12 (Ph. 1)	19,978	#####	1,629	-	-	-	135	-	5,280	-	CE	SP/MP Grids #220, #326	1920, 1930, 1940, 1950 Cast Iron 4", 6", and 8" SP Pipe. SAG12 Phases 1 and 2 were added to the 2025 plan to help reduce the amount of SP pipe on the system. They were not chosen as part of the risk ranking. We ended up pulling some of this work into 2024 and pushing some into 2026 to balance crew availability. The SP system in this area has had over +1,000 maintenance calls on this system in the previous two years before project selected. Also to the west of this project MDOT has work coming east in the upcoming years so we are replacing pipe ahead of their work.
PPN4032SEROK	19946,7,9,50	MP - Plastic	SE - Royal Oak	Royal Oak	ROK4 (2,3,5,6)	13,099	-	26,989	7,735	5,364	-	443	-	28,581	-	CE	SP/MP Grids #43, #408, #468	1920, 1930, 1940, 1950 Bare Steel and Threaded & Coupled 2" and 6" MP Pipe. ROK4 Project was started in 2023. Phases 4, 5 and 6 are carrying over from 2024 and Phase 3 was added to complete the work efficiently in one area.
PPN4036SEROK	19482	MP - Plastic	SE - Royal Oak	Royal Oak	ROK6 (Ph. 5)	160	-	17,595	-	160	-	85	-	17,763	-	CE	SP/MP Grids #141	1940, 1950 Bare Steel and Threaded & Coupled 2", 4" MP Pipe. This project was added to the 2025 plan as we had additional capacity for work and this phases had been scoped and planned early as a potential contingency project. This phase is part of a larger grid project started in 2024 but will be fully constructed in 2025, so it isn't listed as carryover. The risk rank in this report applies only to this phase, not the higher-risk phase the overall grid project was built around.
PPN4071SEROK	20561	SP - Plastic	SE - Royal Oak	Royal Oak	ROK13 (Ph. 1)	24,770	#####	1,305	3,631	-	-	3,179	-	21,729	-	CE	SP/MP Grids #13	1920, 1930, 1940 Cast Iron and Bare Steel 6", 8", 10", 12" SP Pipe. This project was added due to risk rank SP/MP Grid #13 and the companies goal to have all SP pipe retired by 2030.
PPN4058SEROK	20409	SP - Plastic	SE - Royal Oak	Royal Oak	ROK14	10,088	9,266	854	-	-	-	356	-	8,793	-	CE	SP/MP Grids #13	1900, 1910, 1920, 1930, 1940 Cast Iron 6", 8", 10", 16" SP Pipe. This project was added due to risk rank SP/MP Grid #13 and the companies goal to have all SP pipe retired by 2030.
PPN4097SEROK	21949,52,3,4	MP - Plastic	SE - Royal Oak	Royal Oak	ROK15 (Ph. 1-4)	3,913	-	3,158	3,535	378	-	39	3,735	6,618	-	CE	#4 SP/MP Segments	1920, 1950 Bare Steel and Threaded & Coupled 2" MP Pipe risk ranked #4 for SP/MP Pipe Segments. This pipe is within SP/MP Grids #20, #78.
PPN4098SEROK	21957	MP - Plastic	SE - Royal Oak	Royal Oak	ROK16 (Ph. 1)	1,108	-	318	1,108	-	-	61	-	1,130	-	CE	#1 SP/MP Segments	1940, 1950 Bare Steel 4" MP Pipe that was risk ranked #1 for SP/MP Pipe Segments. This pipe falls within SP/MP Grid #44.
PPN4099SEROK	21958	MP - Plastic	SE - Royal Oak	Royal Oak	ROK17 (Ph. 1)	441	-	-	441	-	-	82	-	500	-	CE	#10 SP/MP Segments	1950 Bare Steel 2" MP Pipe that was risk ranked #10 for SP/MP Pipe Segments. This pipe falls within SP/MP Grid #50.
PPN4117SWOWS	21989	HP - Steel	NE - Flint	Owosso	OWS1	7,700	-	280	7,700	-	-	-	-	-	8,050	CE	#12 HP	1933 Bare Steel 6" HP Pipe that was risk ranked #12 for HP segments.
PPN4125SWOWS	22607,8	MP - Plastic	NE - Flint	Owosso	OWS2 (Ph. 1,2)	13,224	-	7,382	1,239	11,985	-	1,287	11,841	23,300	-	CE	SP/MP Grid #55	1925 Bare Steel, T&C 6" MP Pipe that was selected as a SME Project to address 3 - 5 lb. MP system in Corunna
PPN4077NEMDL	20620	MP - Plastic	NE - Midland	Midland	MDL2 (Ph. 1)	12,680	-	13,180	-	-	-	-	6,225	13,190	-	CE	#5 SP/MP Segments	1920 Bare Steel 6" MP Pipe that was risk ranked #5 for MP Segments. We added additional footage to avoid tying into 1928 bare steel pipe. This project expands across SP/MP Grids #5, #235, #430. This work helps to retire pipe ahead of planned multi=phase civic work with Road Commission.
PPN4063SEMAC	20624,5,6,7,8,9,30,31	MP Plastic	SE - Macomb	Macomb	MAC12 (Ph. 1-8)	81,432	-	37,228	16,426	65,006	-	2,308	10,376	111,406	-	CE	SP/MP Grid #1	1900, 1920, 1930, 1940, 1950 Bare Steel and Threaded & Coupled 2", 4", and 6" MP Pipe. This pipe was the #1 Risk Ranked SP/MP Grid. Additionally over 2 miles of pipe not cathodically protected.
PPN4095SEMAC	21922	MP - Plastic	SE - Macomb	Macomb	MAC14 (Ph. 2)	14,837	-	2,096	-	14,837	-	320	4,730	19,860	-	CE	#6 SP/MP Segments	1920 through 1940 Threaded & Coupled 2", 4" MP Pipe that was risk ranked #6 for MP Segments. MAC14 is a larger Grid project to be completed in future years. The pipe is within the SP/MP Grid #117
PPN4106SELIV	22036	HP - Steel	SE - Livonia	Livonia	LIV6 (Ph. 1) Line 1019W (TOD)	-	-	5,050	-	-	-	-	-	2,778	5,050	Contractor	TOD	1960 C&W 10" HP Pipe operating at >20% SMYS. This is the 1st of three phases addressing pipe along Middlebelt Road. This is a SME Project for TOD addressing external corrosion concerns.
PPN4012SELIV	19186	MP - Plastic	SE - Livonia	Livonia	LIV3 (Ph. 5)	14,569	-	3,054	-	14,569	-	-	-	17,623	-	CE	SP/MP Grids #972	1940 Bare Steel 4" MP Pipe and 1950 Threaded & Coupled 2" MP Pipe. LIV3 Grid was started in 2024. To keep crews on the project make economical sense versus having them move to alternate projects. This phase is part of a larger grid project started in 2024 but will be fully constructed in 2025, so it isn't listed as carryover. The risk rank in this report applies only to this phase, not the higher-risk phase the overall grid project was built around.
PPN4050SELIV	20325,6,7,8,9,31	MP - Plastic	SE - Livonia	Livonia	LIV4 (Ph.1-5,7)	70,901	-	739	4,701	66,200	-	1,209	4,054	71,956	-	CE	SP/MP Grids #7	1950 Threaded & Coupled 2', 4", 6" MP Pipe. Phases 3,4,5 are in the 7th risk ranked grid for SP/MP Pipe. We decided to complete all of the phases for this LIV4 project in order to take advantage of crew efficiency working in one area.
PPN4114SWLAN	21985	HP - Steel	SW - Lansing/ Jackson	Lansing	LAN8 (Lk. Lansing/Larch)	4,736	-	1,227	4,736	-	-	-	-	-	5,840	Contractor	#8 HP	1940 Bare Steel 6" HP Pipe that was risk ranked #8 for HP Segments. The city has a Combined Sewer Overflow (CSO) Project and we have worked with them to coordinate this work.
PPN4113SWLAN	21986	HP - Steel	SW - Lansing/ Jackson	Lansing	LAN9 (Lk, Lansing Rd)	5,725	-	164	5,725	-	-	-	-	-	5,800	Contractor	#4 HP	1940 Bare Steel 6" HP Pipe that was risk ranked #4 for HP Segments. Additionally we added MP pipe to be installed to eliminate long sided HP services.
PPN4009SWLAN	19205,6,7,8,9	MP - Plastic	SW - Lansing/ Jackson	Lansing	LAN4 (Ph. 4-8)	33,735	-	34,002	10,319	23,416	-	1,586	7,863	83,105	-	CE	SP/MP Grids #33, #116, #135, #175, #200, #211, #423, #1538	1900, 1920, 1930, 1940, and 1950 Bare Steel and Threaded & Coupled 2" MP Pipe. LAN4 Project was started in 2024. Phases 4,5, are currently under construction and retirement will roll into 2025. Phases 6,7,8 were rolled into 2025 to keep crews working efficiently on this project.
PPN4017SWLAN	22576	MP - Steel	SW - Lansing/ Jackson	Lansing	LAN5 (Ph. 11)	155	-	412	-	-	-	-	155	1,270	-	Contractor	SP/MP Grids #22	1910 Bare Steel 6" MP Pipe. LAN5 Phase 9 which is under construction in 2024 had to have a portion of pipe split off and made into this Phase 11. This phase is handling the steel pipe in the Red Cedar River Crossing. Close work with the municipality on bridge work.

U21806-MNSC-CE-0075_Pascarello_Attachment_2

Parent Project Number (PPN)	DAPP #	Pipe Pressure	Headquarters	Project Location	Project Name	Total Vintage Retired	Cast Iron	Coated & Wrapped (C&W)	Bare Steel (BS)	Threaded & Coupled (T&C)	Wrought Iron	Plastic	Code 3 (Ft)	Install Plastic	Install Steel	Construct	Risk Rank	Selection Reason
PPN4102SWLAN	21973,4	MP - Plastic	SW - Lansing/ Jackson	Lansing	LAN7 (Eaton & Mason)	270	-	1,655	270	-	-	166	1,294	1,634	-	CE	#7 and #9 SP/MP Segments	1940 Bare Steel 2" MP Pipe and 1950 Coated & Wrapped Pipe that were risk ranked #7 and #9 for MP segments. These pipe segments are part of the SP/MP Grids #35 and #40.
PPN4042SWKAL	19657,8,60, 61,21010	SP - Plastic, HP - Steel	SW - Lansing/ Jackson	Kalamazoo	KAL2 (Ph. 1,2,4,5,10)	46,294	######	4,385	2,485	-	114	2,167	-	47,930	2,345	CE	SP/MP Grid #138	1900, 1910, 1920, 1930, 1940, 1950 Cast Iron, Wrought Iron and Bare Steel 2", 4", 6", 8", and 10" SP Pipe. This grid was originally planned in 2024 but was removed for resource availability reasons. Plan to construct 1/2 of this grid in 2025 and replace a small segment of Vintage HP pipe. Additionally, due to Kalamazoo's permit restrictions which prohibit construction activities during winter months, it is important that we prioritize and complete this project within the limited construction window available. This ensures that we can effectively utilize the permissible construction period and avoid delays that could arise from seasonal restrictions.
PPN4100SWKAL	21969, 30156	HP - Steel	SW - Lansing/ Jackson	Kalamazoo	KAL6 (W. Main & W. Michigan)	6,569	-	362	6,569	-	-	-	-	-	9,994	Contractor	#9 HP	1950 Bare Steel 6" HP Pipe that was risk ranked #9 for HP Segments. Existing line has casing at Amtrak RR crossing, which is cathodically shorted and also punctured so additional piping was added. Compliance issue with this casing and this project will resolve.
PPN4090SEHWL	21618,21,22	HP - Steel	NE - Flint	Howell	HWL2 (Ph. 1,4,5)	5,755	-	1,766	5,755	-	-	10	-	-	6,595	CE	#7 HP	1928 Bare Steel 6" HP Pipe that was risked ranked #7 for HP segments. Adjacent to a CE Initiated Project to replace additional bare steel HP Pipe.
PPN4105NEFLT	22021	MP Plastic	NE - Flint	Flint	FLT6 (Ph. 2)	2,139	-	144	178	1,961	-	21	-	3,271	-	CE	SP/MP Grid #581	1940, 1950 Bare Steel and Threaded & Coupled 2" MP Pipe. This work was added to the FLT6 Phase 1 project to take advantage of crew availability and close proximity to FLT6 Phase 1. We would be causing a risk if we replaced the HP on PH1 and not replace this vintage pipe on PH2.
PPN4067NEFLT	20657,8,9	MP - Plastic, HP - Steel	NE - Flint	Flint	FLT5 (Ph. 1-3)	22,283	-	23,020	18,225	4,058	-	1,098	-	44,086	-	CE	#1 HP	1928 Bare Steel 6" HP Pipe that was risked ranked #1 for HP segments. Able to retire some HP-Steel and replace with MP-Plastic. The MP pipe expands across SP/MP Grids #90, #94, #103, #226, #299. By combining this work in one year less disruption to the municipality. By retiring this vintage pipe, we hope to help the city relive some traffic routing conditions with their future MDOT work.
PPN4105NEFLT	21855	HP - Steel	NE - Flint	Flint	FLT6 (Ph. 1) Line 1045	5,984	-	-	5,984	-	-	-	-	-	4,729	Contractor	#10 HP	1940 Bare Steel 12" HP Pipe that was risk ranked #10 for HP segments and was part of a request for SME replacement. Multiple couplings on this line.
PPN4107NEBCY	21807	MP - Plastic	NE - Midland	Bay City	BCY3 (Ph. 1)	3,333	-	56	3,333	-	-	2	-	1,000	-	CE	#2 SP/MP Segments	1946 Bare Steel 2" MP Pipe that was risk ranked #2 for MP Segments. This pipe expands across SP/MP Grids #34 and #46
PPN4044NEBCY	19914, 30349,50	SP - Plastic	NE - Saginaw	Bay City	BCY2 (Ph. 3,7,8)	31,179	######	9,054	805	1,088	-	2,815	-	30,990	-	CE	SP/MP Grids #83, 119, 137,310, 316	1940 and 1950 SP Cast Pipe that has been coordinated with city work on multiple streets within the Bay City Area. By removing our vintage main ahead of city work we can avoid future disruption to completed road work. Phase 3 moves some pipe that the city is addressing a "sinking" road issue they are trying to address. This BCY2 project has been broken up into multiple phases to work around civic work, MDOT Bridge work, and traffic routing.
PPN4075NEALM	20617, 30218,9	MP Plastic	NE - Midland	Alma	ALM2 (4,6,7)	31,355	-	-	5,212	27,428	2,856	-	500	38,700	-	CE	SP/MP Grids #194, #300	1900, 1940, 1950 Wrought Iron, Bare Steel, and Threaded & Coupled 2" and 4" MP Pipe. This project was added to the plan as the city (St. Louis) had planned civic work and we took advantage of removing the vintage pipe ahead of their work so that we would not need to come back and tear up newly paved roads.
PPN4111NEALM	21667	HP - Steel	NE - Midland	Alma	ALM5 (Ph. 1) Line 1070G	14,681	-	-	14,681	-	-	-	-	125	14,000	CE	TOD	1945 Bare Steel 6" HP Pipe that was selected as a SME Project due to multiple incidents of line being struck by outside parties. (Shallow pipe within a farm field)
PPN4110NEALM	21767	MP - Plastic	NE - Midland	Alma	ALM4 (Ph. 1)	3,909	-	2,085	3,909	-	-	346	-	4,900	-	CE	#8 SP/MP Segments	Pre 1930 Bare Steel 2" MP Pipe that was risk ranked #8 for MP Segments. This pipe is located within the SP/MP Grid #76. Completing this work will help with future civic work in the city (Ithaca).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
EIRP Project List Detail

Case No.: U-21806
Exhibit No.: A- 142 (KAP-12)
Page: 1 of 2
Witness: KAPascarello
Date: May 2025

Case No. U-21806
WP-KAP-3

2025 Projects List by Region

	Zone/Region	S=Segment G=Grid HP=High Pressure (Steel)	DRAM Risk Rank SP/MP/HP	MP/SP Vint Main (miles)	HP Vint Main (miles)	Installed MP Plastic	Installed HP Steel	HP SIZE
Northeast Zone				**24.2**	**12.9**	**36.2**	**9.4**	
	HWL2 (Ph 1,4,5) (Fowlerville)	HP	7		1.0		1.2	8" S-HP
	OWS2 Corruna (Ph 1,2)	S	55	2.5		4.4		
	FLT6 (Ph 1,2) Line 1045	HP	10	0.5	1.1	0.6	0.9	
	FLT5 (Ph 1,2,3) *includes FLT8 & FLT9*	MP/HP	2, 10	3.8	2.7	8.3		retire
	OWS1 - Durand from SW Area	HP	12		1.5		1.5	4", 6" S-HP
	BCY3 (Ph 1) Section 135509	S	2	0.0		0.2		
	ALM2 (Ph 4, 7 and 6) St. Louis	MP	194, 300	6.7		7.3		
	ALM4_1 Section 110336 Ithaca	S	8	0.7		0.9		
	MDL2 (Ph 1)	S	5	2.4		2.5		
	ALM5 PH1 Line 1070g	HP	TIMP Model		2.0	0.02	2.7	8" S-HP
	SAG11 (Ph 1,2) Section 125424	S	3	1.6		2.2		
	SAG12 (Ph 1)	S	39	0.0		1.0		
	BCY2 (Ph 3,7,8)	S	42	5.9		8.4		
	SAG8 Frankenmuth(Junction Rd)	HP	2		4.2		2.6	6" S-HP
	SAG9 Shields (Center Rd S of M46) & Ph2	HP	3		0.5	0.3	0.5	12" S-HP
Southeast Zone				**55.7**	**0.0**	**57.9**	**0.0**	
	MAC14 (Ph 2)	S	6	3.8		3.8		
	MAC12 (Ph 1,2,3,4,5,6,7,8)	G	1	17.8		21.1		
	LIV3 Phase 5	S	972	3.3		3.3		
	LIV4 (Ph 1,2,3,4,5,7)	S	7	13.5		13.6		
	ROK4 (Ph 2,3,5,6)	S	43	7.1		5.4		
	ROK16 Section 026016 Bloomfield Hills	S	1	0.2		0.2		
	ROK17 Section 026131 Birmingham	S	10	0.1		0.1		
	ROK15 (Ph 1,2,3,4) Section 016105	S	4	1.3		1.3		
	ROK13 (Ph 1)	S	13	3.8		4.1		
	ROK6 Phase 5	S	156	3.0		3.4		
	ROK14	S	13	2.1		1.7		
Southwest Zone				**18.1**	**3.6**	**25.8**	**4.5**	
	LAN7 Section 020105 Mason	S	**7**	0.2		0.3		
	LAN4 (Ph 4,5,6,7,8)	S	116	7.8		**15.7**		
	LAN5 Phase 11	S	**36**	0.0		0.2		
	LAN7 Section 020334 Eaton	S	**9**	0.04		0.04		
	KAL2 (Ph 1,2,4,5,10 HP)	G	138	9.6	0.5	9.1	0.4	8" S-HP
	LAN9 - Lake Lansing Rd	HP	4		1.0		1.1	12" S-HP
	LAN8 - Lansing (north of svc center)	HP	8		0.9		1.1	12" S-HP
	KAL6 (W. Michigan Ave & W. Main)	HP	9		**1.2**		**1.9**	8" S-HP
	JAC1 Section 555427 Tecumseh	S	**5**	0.4		0.4		
			Totals	**98.1**	**16.5**	**120.0**	**13.9**	
TOD Projects								
	SAG6 TOD Line 1087g	HP	TOD	0.0	*4.8*		6.6	12" S-HP
	LIV6 Ph1 Line 1019W	HP	TOD	0.0	0.0	0.5	1.0	**12" S-HP**
			Grand Total	**98.1**	**21.3**	**120.5**	**21.5**	

The 2025 EIRP projects listed in this workpaper were internally approved on August 6, 2024. EIRP projects do not have completed business cases since the projects are selected using the Company's Distribution Risk Analysis Model ("DRAM") to target highest ranked risk pipe segments and include other factors such as project size, location, system characteristics, and municipality planned projects, such as road reconstruction, sanitary or water main projects, or other local, state, and federally funded projects.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
EIRP Project List Detail

Case No.: U-21806
Exhibit No.: A- 142 (KAP-12)
Page: 2 of 2
Witness: KAPascarello
Date: May 2025

Case No. U-21806
WP-KAP-3

2026 Projects List by Region

	Zone/Region	S=Segment G=Grid HP=High Pressure (Steel)	DRAM Risk Rank SP/MP/HP	MP/SP Vint Main (miles)	HP Vint Main (miles)	Installed MP Plastic	Installed HP Steel	HP SIZE
Northeast Zone				**50.0**	**2.6**	**55.0**	**2.5**	
	FLT11 (Ph 1,2,3,4,5,6)	G	75	13.1		14.5		
	OWS3 (Ph 1,2)	S	54	4.5		5.4		
	FLT5 Phase 5 *includes FLT10*	S	9 and 23	2.0		2.2		
	GRV2 Imlay City (E Capac Rd) Line 1041	HP	14		0.6	0.1	0.4	4" S-HP
	SAG12 (Ph 1)	S	17	4.1		3.0		
	SAG7 (Ph 1)	S	6	1.5		1.7		
	SAG4 (Ph 1,2,3)	SP	21, 41, 76	12.1		14.5		
	BCY2 (Ph 2) carryover from 2025	G	1	6.1		6.0	0.0	
	ALM2 (Ph 1,7,8) carryover from 2025	S	3	6.6		7.6		
	ALM5 (Ph 2) Line 1070g	HP	TIMP Model		2.0		2.1	8" S-HP
Southeast Zone				**53.3**	**0.2**	**60.9**	**0.2**	
	MAC13 (Ph 5,6,7) Gloede Segment	S	4	2.4		3.2		
	MAC11 (Ph 2,3,5,6,7,11)	S/HP	1, 4	11.1	0.2	12.0	0.2	6" S-HP
	MAC12 (Ph 9) carryover from 2025	G		2.0		2.1		
	ROK12 (Ph 1,2)	S	2, 7	3.9		3.9		
	ROK8 (Ph 4)	S	7	0.8		0.9		
	ROK10 (Ph 1,2,4)	S	62	5.0		5.0		
	ROK21	S	60	2.9		*3.1*		
	ROK26	S	48	2.7		*3.4*		
	ROK10 (Ph 3,5,6)	S	62	5.9		*7.6*		
	ROK7 (Ph 4,5,6,7,8)	G	35	16.1		*19.3*		
	LIV4 (Ph 6) carryover from 2025	S	471	0.5		0.5		
Southwest Zone				**17.1**	**8.2**	**20.0**	**8.3**	
	KAL3 (Ph 8,9,10)	G	3	5.0		5.5		
	LAN4 Ph8 carryover from 2025	S	116	1.7		2.3		
	LAN12 (040121 Okemos)	S	5	0.2		0.2		
	KAL7 (Michigan Ave Galesburg)	HP	1		3.0		3.0	6" S-HP
	KAL8 (VW Ave east of Schoolcraft)	HP	5		2.8		2.8	6" S-HP
	LAN13 Thornapple Lake Rd at M66	HP	6		2.4		2.4	6" S-HP
	KAL11 (Ph 1,2,3) - Bangor	S	83	7.1		7.6		
	LAN14 Mt Hope and Chippewa (Meridian Twp)	S	16	3.1		4.4		
			Totals	**120.4**	**11.0**	**135.8**	**11.0**	
TOD Projects								
	LIV6 Ph2 Line 1019W	HP	Livonia		0.0	0.4	0.9	12" S-HP
	LAN10 Ph1 & Ph2 Line 1022	HP	Lansing		0.0		2.2	12" S-HP
			Grand Total	**120.4**	**11.0**	**136.2**	**14.1**	

The 2026 EIRP projects listed in this workpaper were internally approved on August 20, 2024. EIRP projects do not have completed business cases since the projects are selected using the Company's Distribution Risk Analysis Model ("DRAM") to target highest ranked risk pipe segments and include other factors such as project size, location, system characteristics, and municipality planned projects, such as road reconstruction, sanitary or water main projects, or other local, state, and federally funded projects.

EXHIBIT A-143 (JPP-5)
IS CONFIDENTIAL AND
BEING FILED UNDER SEAL
WITH THE MPSC

EXHIBIT A-144 (JPP-6)
IS CONFIDENTIAL AND
BEING FILED UNDER SEAL
WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
EIRP OM&C Headcount Analysis

Case No.: U-21806
Exhibit No.: A-145 (JPP-7)
Page: 1 of 1
Witness: JPPnacek
Date: May 2025

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Year	**Headcount (year ending) [1]**	**Headcount change from previous year**	**Cumulative Headcount loss since 2020**	**# of Employee Hired**	**Cumulative Employee's hired since 2020**	**Number of Employee lost from previous year**	**Cumulative Employee loss since 2020**
2020	**495**						
2021	486	9	9	128	128	137	137
2022	423	63	72	27	155	90	227
2023	414	9	81	23	178	32	259
2024	379	35	**116**	38	**216**	73	**332**
2025 Projected				45	45		
2026 Projected				100	**145**		

Average Number Employees since 2020	439
Employee Turnover Rate	76%

[1] Data for 2020-2024 EIRP Performance reports Attachment 5
Note: Headcount is OM&C only

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Revenue Deficiency
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-146 (HLR-52)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	(a) Description	(b) Source - Adjustments	(c) Initial Filing {1}	(d) Adjustments	(e) Rebuttal Position
1	Rate Base	Exhibit No.: A-147 (HLR-53)	11,750,740	(183,308)	11,567,432
2	Adjusted Net Operating Income	Exhibit No.: A-151 (HLR-57)	545,492	11,272	556,763
3	Overall Rate of Return	Line 2 / line 1	4.64%	0.17%	4.81%
4	Required Rate of Return	Exhibit No.: A-14 (MRB-1)	6.22%	0.00%	6.22%
5	Income Required	Line 1 * line 4	730,838	(11,401)	719,437
6	Income Deficiency (Sufficiency)	Line 5 - line 2	185,346	(22,672)	162,674
7	Revenue Conversion Factor		1.3381	1.3381	1.3381
8	Revenue Deficiency (Sufficiency)	Line 6 * line 7	248,008	(30,338)	217,670

Notes

{1} Source: Exhibit No.: A-12 (HLR-28)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Rate Base
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-147 (HLR-53)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	(a) Description	(b) Source - Adjustments	(c) Initial Filing {1}	(d) Adjustments	(e) Rebuttal Position
1	Total Utility Plant	Exhibit No.: A-149 (HLR-55)	14,907,264	(62,095)	14,845,170
2	Depreciation Reserve	Exhibit No.: A-149 (HLR-55)	(4,665,713)	21,795	(4,643,918)
3	Customer Advances for Construction	---	(19,159)	-	(19,159)
4	Net Unamortized MGP	Company witness Rayl	19,967	471	20,438
5	Net Utility Plant	Sum of lines 1 through 4	10,242,359	(39,829)	10,202,530
6	Working Capital	Exhibit No.: A-150 (HLR-56)	1,508,381	(143,479)	1,364,902
7	Total Rate Base	Line 5 + line 6	11,750,740	(183,308)	11,567,432

Notes

{1} Source: Exhibit No.: A-12 (HLR-31)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Utility Plant
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-148 (HLR-54)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	(a) Description	(b) Source	(c) Utility Plant	(d) Depreciation Reserve	(e) Net Utility Plant
1	Utility Plant - Initial Filing	Exhibit No.: A-12 (HLR-31)	14,907,264	(4,665,713)	10,241,552
	Adjustments				
2	Correction of Depreciation Rates	Exhibit No.: A-149 (HLR-55), line 1	-	20,447	20,447
3	2024 IT capital expenditures	Exhibit No.: A-149 (HLR-55), line 2	(5,668)	2,078	(3,590)
4	IT Application Currency Corporate Capital Project	Exhibit No.: A-149 (HLR-55), line 3	(24)	4	(20)
5	Application Currency Project - Electric & Gas Shared	Exhibit No.: A-149 (HLR-55), line 4	(31)	5	(26)
6	ARP-Collaboration	Exhibit No.: A-149 (HLR-55), line 5	(10)	1	(8)
7	ARP-Physical Security	Exhibit No.: A-149 (HLR-55), line 6	(127)	19	(108)
8	Next Generation eSOMS	Exhibit No.: A-149 (HLR-55), line 7	(63)	6	(57)
9	Project B-GL-00251	Exhibit No.: A-149 (HLR-55), line 8	(417)	12	(405)
10	Project B-GL-03042	Exhibit No.: A-149 (HLR-55), line 9	(3)	0	(3)
11	Compression & Storage 2024 Underspend	Exhibit No.: A-149 (HLR-55), line 10	(7,563)	344	(7,219)
12	Lansing Service Center	Exhibit No.: A-149 (HLR-55), line 11	(16,720)	216	(16,504)
13	Hastings Service Center	Exhibit No.: A-149 (HLR-55), line 12	(19)	0	(19)
14	Riverside Storage Facility Utility Plant	Exhibit No.: A-149 (HLR-55), line 13	11,349	(2,293)	9,056
15	Distribution Gas Ops - Comp & Controls	Exhibit No.: A-149 (HLR-55), line 14	(380)	5	(375)
16	MCNM - reduced estimate for Line 1010 project	Exhibit No.: A-149 (HLR-55), line 15	(5,804)	116	(5,688)
17	Compliance and Control Projects	Exhibit No.: A-149 (HLR-55), line 16	(265)	6	(259)
18	Material Condition - ERIP	Exhibit No.: A-149 (HLR-55), line 17	(2,991)	67	(2,925)
19	New Business - Mains, Services, and Meter Stands	Exhibit No.: A-149 (HLR-55), line 18	(12,790)	326	(12,464)
20	New Business - Large New Business Projects	Exhibit No.: A-149 (HLR-55), line 19	(5,043)	137	(4,905)
21	Asset Relocation - Civic Improvement Projects	Exhibit No.: A-149 (HLR-55), line 20	(14,365)	282	(14,083)
22	Asset Relocation - Reimbursable Projects	Exhibit No.: A-149 (HLR-55), line 21	(1,163)	17	(1,146)
23	Total Adjustments	Sum of lines 2 through 14	(62,095)	21,795	(40,300)
24	Utility Plant - Rebuttal Position	Line 1 + line 23	14,845,170	(4,643,918)	10,201,252

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Spending Reconciliation
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-149 (HLR-55)

Witness: Heather L. Rayl
Date: May 2025

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
				Cap Ex Adj. Increase / (Decrease)						Projected Test Year Impacts					
Line No.	Description	Plant Model Category	Source	12-Mo Ended 12/31/23 Increase / (Decrease)	12-Mo Ended 12/31/24 Increase / (Decrease)	10-Mo Ended 10/31/25 Increase / (Decrease)	12-Mo Ended 10/31/26 Increase / (Decrease)	Composite Deprec. Rate	Property Tax Rate	Total CapEx Adjustment Increase / (Decrease)	Avg. Plant Adjustment Increase / (Decrease)	Avg. Accum. Deprec. Increase / (Decrease)	Avg. Net RB Increase / (Decrease)	Deprec. Increase / (Decrease)	Prop. Tax Increase / (Decrease)
1	Correction of Depreciation Rates	Various	Company witness Rayl	-	-	-	-	0.00%	1.40%	-	-	(20,447)	20,447	(8,856)	-
2	2024 IT capital expenditures	Information Technology	Company witness Baker	-	(5,668)	-	-	20.00%	1.40%	(5,668)	(5,668)	(2,078)	(3,590)	(1,134)	(79)
3	IT Application Currency Corporate Capital Project	Information Technology	Company witness Baker	-	-	(15)	(18)	20.00%	1.40%	(33)	(24)	(4)	(20)	(5)	(0)
4	Application Currency Project - Electric & Gas Shared	Information Technology	Company witness Baker	-	-	(19)	(23)	20.00%	1.40%	(42)	(31)	(5)	(26)	(6)	(0)
5	ARP-Collaboration	Information Technology	Company witness Baker	-	-	(6)	(7)	20.00%	1.40%	(13)	(10)	(1)	(8)	(2)	(0)
6	ARP-Physical Security	Information Technology	Company witness Baker	-	-	(73)	(109)	20.00%	1.40%	(182)	(127)	(19)	(108)	(25)	(2)
7	Next Generation eSOMS	Information Technology	Company witness Baker	-	-	-	(126)	20.00%	1.40%	(126)	(63)	(6)	(57)	(13)	(1)
8	Project B-GL-00251	Transmission	Company witness Griffin	-	(159)	(283)	50	2.29%	1.40%	(392)	(417)	(12)	(405)	(10)	(6)
9	Project B-GL-03042	Transmission	Company witness Griffin	(2)	(2)	-	-	2.29%	1.40%	(3)	(3)	(0)	(3)	(0)	(0)
10	Compression & Storage 2024 Underspend	Compression/Storage	Company witness Joyce	-	(7,563)	-	-	2.48%	1.40%	(7,563)	(7,563)	(344)	(7,219)	(188)	(106)
11	Lansing Service Center	Facilities	Company witness Guinn	-	-	(13,120)	(7,199)	1.56%	1.40%	(20,319)	(16,720)	(216)	(16,504)	(261)	(234)
12	Hastings Service Center	Facilities	Company witness Guinn	-	-	(19)	-	1.56%	1.40%	(19)	(19)	(0)	(19)	(0)	(0)
13	Riverside Storage Facility Utility Plant	Compression/Storage	Company witness Myers	-	-	-	-	2.09%	1.40%	-	11,349	2,293	9,056	237	159
14	Distribution Gas Ops - Comp & Controls	Distribution	Company witness Pascarello	-	-	-	(759)	2.54%	1.40%	(759)	(380)	(5)	(375)	(10)	(5)
15	MCNM - reduced estimate for Line 1010 project	Distribution	Company witness Pascarello	-	-	(4,054)	(3,500)	2.54%	1.40%	(7,554)	(5,804)	(116)	(5,688)	(147)	(81)
16	Compliance and Control Projects	Distribution	Company witness Pascarello	-	-	(265)	-	2.54%	1.40%	(265)	(265)	(6)	(259)	(7)	(4)
17	Material Condition - ERIP	Distribution	Company witness Pascarello	-	-	(2,710)	(562)	2.54%	1.40%	(3,272)	(2,991)	(67)	(2,925)	(76)	(42)
18	New Business - Mains, Services, and Meter Stands	Distribution	Company witness Warriner	-	(3,067)	(5,714)	(8,018)	2.54%	1.40%	(16,799)	(12,790)	(326)	(12,464)	(324)	(179)
19	New Business - Large New Business Projects	Distribution	Company witness Warriner	-	(1,948)	(685)	(4,819)	2.54%	1.40%	(7,452)	(5,043)	(137)	(4,905)	(128)	(71)
20	Asset Relocation - Civic Improvement Projects	Distribution	Company witness Warriner	-	-	(9,408)	(9,913)	2.54%	1.40%	(19,321)	(14,365)	(282)	(14,083)	(364)	(201)
21	Asset Relocation - Reimbursable Projects	Distribution	Company witness Warriner	-	-	(203)	(1,919)	2.54%	1.40%	(2,122)	(1,163)	(17)	(1,146)	(29)	(16)
22	Total		Sum of lines 1 through 21	(2)	(18,407)	(36,574)	(36,922)			(91,904)	(62,095)	(21,795)	(40,300)	(11,347)	(869)

Notes

Source: Col. (h): WP-HLR-20
Source: Col. (i): Exhibit No.: A-99 (BJV-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Working Capital
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-150 (HLR-56)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	Description	(a) Initial Filing {1}	(b) Adjustments		(c) Rebuttal Position
1	Cash, cash equivalents, and restricted cash	$ 28,393	$ (5,263)	{2}	$ 23,130
2	Accounts and notes receivable	109,689	-		109,689
3	Materials and supplies	55,983	-		55,983
4	Gas stored underground	382,036	-		382,036
5	Prepayments	543,707	-		543,707
6	Accrued revenue	123,914	-		123,914
7	Deferred taxes	176,164	-		176,164
8	Deferred debits	466,865	(10,411)	{3}	456,454
9	Total assets	1,886,750	(15,674)		1,871,076
10	Accounts payable	234,904	-		234,904
11	Customer deposits	11,793	-		11,793
12	Accrued interest	42,561	-		42,561
13	Dividends payable	14,780	-		14,780
14	Accrued taxes	12,399	127,805	{4}	140,204
15	Other liabilities	30,215	-		30,215
16	Deferred credits	31,718	-		31,718
17	Total liabilities	378,369	127,805		506,174
18	Working capital	$ 1,508,381	$ (143,479)		$ 1,364,902

Notes

{1} Source: Exhibit No.: A-12 (HLR-34)

{2} Source: Company witness Bleckman

{3}

Removal of Riverside Storage regulatory asset	Source: Company witness Myers	(7,398)
Correction of projected working capital S4/HANA cloud implementation adjustment	Source: Company witness Rayl	(1,746)
Correction of projected working capital prepaid cloud implementation adjustment	Source: Company witness Rayl	(1,034)
Removal of non-utility account from working capital	Source: Company witness Rayl	(233)
Total deferred debits adjustment		(10,411)

{4} Source: Company witness Rayl

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Net Operating Income
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-151 (HLR-57)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	(a) Description	(b) Initial Filing {1}	(c) Adjustments {2}	(d) Rebuttal Position
1	Sales Revenues	2,182,075	1,119	2,183,193.80
2	Transportation Revenues	102,396	-	102,396.36
3	Other Revenues	28,666	-	28,666.46
4	Total Operating Revenue	2,313,137	1,119	2,314,256.61
5	Cost of Gas Sold	737,588	-	737,588
6	LAUF	12,709	-	12,709
7	Company Use Gas	5,502	-	5,502
8	Other O&M Expense	297,904	485	298,389
9	Depreciation	374,164	(11,347)	362,817
10	Amortization	10,239	(2,905)	7,334
11	Property Taxes	201,200	(869)	200,331
12	General Taxes	19,785	(461)	19,325
13	Other (Local) Taxes	838	31	869
14	State Income Tax	25,256	1,026	26,281
15	Federal Income Tax	83,757	3,888	87,646
16	Total Operating Expenses	1,768,943	(10,152)	1,758,791
17	Net Operating Income	544,194	11,272	555,466
18	AFUDC	1,298	-	1,298
19	Net Operating Income, Including AFUDC	545,492	11,272	556,763
	Net Operating Income Adjustments			
20	Income Tax Effect of Interest {3}	---- Included in Lines 12, 13, and 14 ----		
21	Interest Synchronization Adjustment {3}	---- Included in Lines 12, 13, and 14 ----		
22	Total Adjusted Net Operating Income	545,492	11,272	556,763

Notes

{1} Source: Col.(b): Exhibit No.: A-12 (HLR-36)
{2} Source: Col.(c): Exhibit No.: A-152 (HLR-58)
{3} Income tax effects of interest and interest synchronization adjustments are included in the calculation of local, state, and federal income tax. The separate calculations can be found on Exhibit No.: A-154 (HLR-60) Exhibit No.: A-155 (HLR-61)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Reconciliation of Adjusted Net Operating Income
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-152 (HLR-58)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	Description	Source	Sales Revenues	Transportation Revenues	Other Revenues	COGS	LAUF	Co. Use	Other O&M	Deprec.	Amort.	Property Taxes	General Taxes	CIT	SIT	FIT	NOI	AFUDC	Adjusted NOI
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
1	Adjusted Net Operating Income - Initial Filing	Exhibit No.: A-12 (HLR-36)	2,182,075	102,396	28,666	737,588	12,709	5,502	297,904	374,164	10,239	201,200	19,785	838	25,256	83,757	544,194	1,298	545,492
	Adjustments																		
2	RIA credit projections	Company witness Sherwani	1,119	-	-	-	-	-	-	-	-	-	-	2	59	222	836	-	836
3	2024 IT Capital Expenditures Underspend	Company witness Baker	-	-	-	-	-	-	(2)	-	-	-	-	0	0	0	1	-	1
4	HR Support Pack & Business Software Upgrade 2025	Company witness Baker	-	-	-	-	-	-	(20)	-	-	-	-	0	1	4	15	-	15
5	HR Support Pack & Business Software Upgrade 2026	Company witness Baker	-	-	-	-	-	-	(40)	-	-	-	-	0	2	8	30	-	30
6	Application Currency Project - Electric & Gas Shared	Company witness Baker	-	-	-	-	-	-	(8)	-	-	-	-	0	0	2	6	-	6
7	Standard Work Plan Program	Company witness Baker	-	-	-	-	-	-	(71)	-	-	-	-	0	4	14	53	-	53
8	Next Generation eSOMS	Company witness Baker	-	-	-	-	-	-	(8)	-	-	-	-	0	0	2	6	-	6
9	Distribution Gas Ops - Comp & Controls	Company witness Pascarello	-	-	-	-	-	-	634	-	-	-	-	(1)	(33)	(126)	(474)	-	(474)
10	Depreciation	Exhibit No.: A-149 (HLR-55) col.(n)	-	-	-	-	-	-	-	(11,347)	-	-	-	18	595	2,254	8,480	-	8,480
11	MPG Amortization	Company witness Foster	-	-	-	-	-	-	-	-	54	-	-	(0)	(3)	(11)	(40)	-	(40)
12	Riverside Storage Field Amortization	Company witness Myers									(2,959)			5	155	588	2,211	-	2,211
13	General Taxes	Company witness Rayl	-	-	-	-	-	-	-	-	-	-	(461)	1	24	92	344	-	344
14	Property Tax Expense	Exhibit No.: A-149 (HLR-55) col.(o)	-	-	-	-	-	-	-	-	-	(869)	-	1	46	173	650	-	650
15	Income Tax Effect of Interest	Exhibit No.: A-154 (HLR-60)	-	-	-	-	-	-	-	-	-	-	-	5	175	664	(844)	-	(844)
16	Interest Synchronization Adjustment	Exhibit No.: A-155 (HLR-61)	-	-	-	-	-	-	-	-	-	-	-	0	1	3	(4)	-	(4)
17	Total Adjustments	Sum of lines 2 through 16	1,119	-	-	-	-	-	485	(11,347)	(2,905)	(869)	(461)	31	1,026	3,888	11,272	-	11,272
18	Adjusted Net Operating Income - Rebuttal Position	Line 1 + line 17	2,183,194	102,396	28,666	737,588	12,709	5,502	298,389	362,817	7,334	200,331	19,325	869	26,281	87,646	555,466	1,298	556,763

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Adjusted Operations & Maintenance Expenses
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-153 (HLR-59)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	Description	(a) Initial Filing {1}	(b) Adjustments {2}	(c) Rebuttal Position
1	LAUF	$ 12,709	$ -	$ 12,709
2	Company Use Gas	5,502	-	5,502
3	Gas Compression Storage	17,577	-	17,577
4	Gas Operations	133,635	-	133,635
5	Pipeline Integrity	18,549	-	18,549
6	Transmission	4,580	-	4,580
7	Gas Engineering & Supply	22,195	634	22,829
8	Customer Experience & Operations	31,846	-	31,846
9	Operations Support	9,525	-	9,525
10	IT & Security - Operations	36,758	-	36,758
11	IT & Security - Investments	17,948	(149)	17,798
12	Pension Plans A/B	(34,801)	-	(34,801)
13	Defined Company Contribution Plan	8,155	-	8,155
14	401(k) Employees' Savings Plan	6,615	-	6,615
15	Active Health Care/ Insurance/ LTD	19,765	-	19,765
16	Retiree Health Care and Life Insurance	(42,702)	-	(42,702)
17	Other Benefits	3,218	-	3,218
18	Pension volatility mechanism amortization	(791)	-	(791)
19	OPEB volatility mechanism amortization	(1,423)	-	(1,423)
20	Incentive Compensation	1,546	-	1,546
21	Uncollectible Expense	15,327	-	15,327
22	Injuries & Damages	2,279	-	2,279
23	MGP Direct Projected Management Costs	930	-	930
24	Corporate Services	26,874	-	26,874
25	Jobwork expenses	61	-	61
26	Interest expense on security deposits	237	-	237
27	OPEN	-	-	-
28	Total Other O&M Expense	316,115	485	316,600
29	Less: LAUF	12,709	-	12,709
30	Less: Company Use Gas	5,502	-	5,502
31	Total Other O&M Expense	$ 297,904	$ 485	$ 298,389

Notes

{1} Source: Col. (e), Exhibit No.: A-12 (HLR-41)
{2} Source: Cols.(g), (h), and (i): Exhibit No.: A-152 (HLR-58)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Income Tax Effect of Interest
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-154 (HLR-60)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate Base	Exhibit No.: A-147 (HLR-53)	11,567,432
2	Weighted Cost of Debt, Excluding JDITC	Exhibit No.: A-14 (MRB-1)	0.0182
3	Allowable Interest Expense	Line 1 * Line 2	210,830
4	Projected Pro-Forma Interest Expense - Initial Filing	Exhibit No.: A-12 (HLR-49)	214,171
5	Increase/ (Decrease) In Allowable Interest Deduction	Line 3 - Line 4	(3,341)
6	Impact on Taxable Income	Line 5 * -1	3,341
7	Impact on Local Income Taxes	Line 6 * Local Income Tax Rate	5
8	Impact on State Income Taxes	Line 6 * State Income Tax Rate	175
9	Impact on Federal Taxable Income	Line 6 - Line 7 - line 8	3,161
10	Impact on Federal Income Tax	Line 9 * Federal Income Tax Rate	664
11	Impact on Net Operating Income	(Line 7 + Line 8 + Line 10) *-1	(844)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Interest Synchronization Adjustment
For the Projected 12-Month Period Ending October 31, 2026
$(000)

Case No.: U-21806
Exhibit No.: A-155 (HLR-61)
Page: 1 of 1
Witness: Heather L. Rayl
Date: May 2025

Line No.	(a) Description	(b) Source	(c) Amount
1	Rate Base	Exhibit No.: A-147 (HLR-53)	11,567,432
2	JDITC Debt-Related Portion of the Capital Structure	Exhibit No.: A-14 (MRB-1)	0.0018
3	Portion of Rate Base Funded by JDITC	Line 1 * Line 2	21,196
4	Cost of JDITC - Debt Portion	Exhibit No.: A-14 (MRB-1)	0.0435
5	Allowable JDITC Interest Expense	Line 3 * Line 4	923
6	Projected Pro-Forma Interest Expense - Initial Filing	Exhibit No.: A-12 (HLR-50)	937
7	Increase/ (Decrease) in Allowable JDITC Interest Expense	Line 5 - Line 6	(15)
8	Impact on Taxable Income	Line 7 * -1	15
9	Impact on Local Income Tax	Line 8 * Local Income Tax Rate	0
10	Impact on State Income Tax	Line 8 * State Income Tax Rate	1
11	Impact on Federal Taxable Income	Line 8 - Line 9 - line 10	14
12	Impact on Federal Income Tax	Line 11 * Federal Income Tax Rate	3
13	Impact on Net Operating Income	(Line 9 + Line 10 + Line 12) *-1	(4)

21806-CE-MNSC-0005

On pages 34-35 of Mr. Denzler's direct testimony, he compares Consumers Energy's customer charge with other Michigan utilities' customer charges.

a. Does Mr. Denzler agree that a utility's service area and customer demographics (e.g., the number of urban and rural customers in the utility's service territory) can affect its costs of providing service to customers?

Response:

I agree that the service area and customer demographics are among many factors that can influence the cost of service and note that what "can" affect cost of service and what actually *does* affect cost of service are two different things.

b. Concerning the utilities that Mr. Denzler named on pages 34-35 of his testimony, did he evaluate whether these utilities' service areas or customer demographics contributed to the different customer charges? If so, what did his evaluation show? Please produce all documents and communications supporting the evaluation if one was performed.

Response:

I did not complete this analysis.

Respondent: Joshua W. Denzler

Question:

75. Witness Griffin testimony at page 14 states "The Company is updating its risk ranking methodology and transitioning its current relative risk model into a probabilistic risk model to ensure investments are concentrated on the right assets." Regarding the most current version of the inputs and results of the probabilistic risk model used by Consumers to develop its testimony:
a. Is this risk model used only to assess risk of Consumers' transmission pipe?
i. If yes, why doesn't Consumers have a similar risk model for the distribution system or specific assets (e.g. regulators)? Please explain.
b. Please provide an explanation of how the probabilistic model estimates risk including but not limited to the likelihood of failure, consequence of failure, and mitigation effectiveness.
i. Please provide all documents and presentations that explain how the risk model derives key inputs, assumptions, and results (e.g. likelihood/probability, consequence/impact, and total risk score).
ii. Please explain what level of granularity is assessed by this risk model. For example, how does Consumers' determine the number of miles of each pipeline or pipeline segment on which it assesses the probability and consequence of failure? Please explain.
iii. Please provide mitigation effectiveness descriptions and calculations specific to the activities discussed in Witness Griffin's testimony.
c. In Excel with supporting data, calculations, and assumptions, please provide the annual risk reduction (in percentage and risk units) accomplished by safety-related activities from 2018-2024. Please provide separately for the transmission system, distribution system, and asset-specific risk models.
i. Please provide a general explanation of how risk reduction was calculated.
ii. Please explain how prior year risk reduction informs Consumers investment and mitigation plan for 2026.
d. In Excel with supporting data, calculations, and assumptions, please provide the forecast annual risk reduction expected to be accomplished by safety-related activities in 2025 and 2026. Please provide separately for the transmission system, distribution system, and asset-specific risk models, which may or may not be supported by Witness Griffin.
e. In Excel with supporting data, calculations, and assumptions, please provide the forecast annual risk reduction expected to be accomplished by safety-related activities from 2027-2035. Please provide separately for the transmission system, distribution system, and asset-specific risk models, which may or may not be supported by Witness Griffin.
f. In Excel, please provide all primary data, assumptions, inputs, and results of the probabilistic risk model for all transmission pipeline segments with working formulas where applicable, including but not limited to the following information. Each row should contain information for one transmission pipeline segment, with corresponding columns containing the following information:
i. Pipeline segment ID.
ii. Miles of pipeline segment.
iii. Likelihood of failure (including supporting data and calculations in separate tabs).
iv. Consequence of Failure (including supporting data and calculations in separate tabs).
v. Total risk score of the pipeline segment.
vi. Mitigation proposed (if any) in 2025, 2026, 2027, 2028, and/or 2029 (e.g. asset relocation).
vii. Mitigation effectiveness of the proposed mitigation(s).
viii. Total risk reduction from the proposed mitigation(s).
ix. Total estimated cost of the proposed mitigation(s).

g. In Excel, please provide the data provided in part (f) for all other risk models (distribution system, asset-based risk models, etc.).
i. Please explain whether the risk scores of these models can be directly compared.
ii. If not, please explain why the model has correctly calculated a risk score.
h. Please demonstrate and explain how the risk model provided above utilized the probabilistic risk model to determine what pipeline to remediate in 2025 and 2026, respectively.
i. Does Consumers seek to prioritize the highest risk assets first?
1. Where it has not, why is this the case?
ii. Please describe any practical or logistical challenges in mitigating other pipe segments than the ones indicated in the response above.

Response:

a. Currently only the Transmission and Transmission Operated by Distribution ("TOD") pipe are included in the probabilistic risk model. A model for Storage Wells is scheduled for use in 2025 and a distribution model is under development and is scheduled for use in 2027. These assets currently utilize a relative risk model.
b. The risk model uses collected data from the Company as well as industry established equations for calculating the magnitude of threats on the pipeline assets. The model the uses Bayesian Statics to calculate a failure rate per unit of length and year. This provides a probability of failure projected out ten years from the date of the model run. The consequence of failure is calculated using building and population data around the assets along with federal insurance equations for consequence. Risk is these two values multiplied. The risk is analyzed across 28 different threats and 9 different modes of failure. The risk models don't currently calculate mitigation effectiveness.
    i. ii. The risk model is run on the entire transmission system annually for the likelihood of failure and consequence of failure. The inspections scheduled are determined by federal regulatory requirements and prioritized by the model results.
    iii. Post assessment analysis by inline inspection and direct assessment analysts determines the effectiveness of the mitigation. This data is then an input to the risk model to inform the model of the overall asset health to provide a future risk profile for the system by asset.
c. This model is not used on the other assets so it is not possible to compare with distribution and other asset groups.
    i. The Company utilizes likelihood of failure thresholds and overall risk to prioritize work. The inputs and results are too large to utilize or view in Excel. CE uses graphical visualization software to monitor risk. Inputs are updated to include new data from projects which impacts the overall risk results. Changes in risk can be seen in the visualization. The threats are time dependent, so these results constantly change. The data visualization allows CE engineers to track the overall risk of each asset.
    ii. Post assessment analysis by inline inspection and direct assessment analysts determines the effectiveness of the mitigation. This data is then an input to

the risk model to inform the model of the overall asset health to provide a future looking risk profile.

d. The risk model currently cannot forecast mitigation due to work performed. Pipeline inspections are required by federal regulation so the work must be completed regardless of the risk mitigation.
e. The risk model currently cannot forecast mitigation due to work performed. Pipeline inspections are required by federal regulation so the work must be completed regardless of the risk mitigation.
f. The confidential attachment U21806-MNSC-CE-0080-CONF_ATT_1 provides the primary data inputs including current risk results that are currently in the model. The consequence of failure can only be viewed within the model and cannot be exported to excel. The model doesn't recommend mitigation measures. The Company selects the mitigation method depending upon the threats.
g. Currently only the Transmission and TOD pipe are included in the probabilistic risk model. The other asset classes are relative risk models.
    i. As these are different types of risk models, they cannot be compared. The assets are prioritized within each asset classification.
    ii. The risk model calculates the best risk score based on inputs and information provided. It is a tool used to prioritize work and requires consistent tuning and updating.
h. The model does not determine remediation but informs the Company on which segments to inspect. The results of the inspection will determine if or where remediation is required on that asset. The is model is only one factor in determining which segments require assessment. Federal regulation is the first guideline utilized. The risk model ensures that they are prioritized correctly and that the correct threats are being assessed.
    i. Yes. The Company's baseline assessment plan was developed in conformance with PHMSA requirements which required ranking from highest to lowest risk
    ii. The Company has inspected most of the gas transmission system. This is a cyclic work; segments are reassessed based on federal regulatory requirements and escalating risk in the risk model. The Company uses competitive bidding to manage project costs.

Witness: MICHAEL P. GRIFFIN

Date: February 3, 2025

U21806-MNSC-CE-0281
Page **1** of **1**

Question:

1. Witness Griffin's response to U21806-CE-0080 (question 75) part (a), states "A model for Storage Wells is scheduled for use in 2025 and a distribution model is under development and is scheduled for use in 2027. These assets currently utilize a relative risk model."

a. Please define "scheduled for use" – how will these models be used?

b. Please provide explanations and supporting documentation for information contained in the "relative risk models" in use for storage wells and distribution assets.

c. Please describe in detail how Consumers utilizes the relative risk models for distribution assets and storage wells.

d. Please provide all results of the relative risk models in Excel, including pipe segment ID, risk rank, total risk score, and other major outputs. Please include all supporting data and calculations, with assumptions and inputs clearly documented and formulas intact (if applicable).

   i. Please add a column for the assets targeted in 2024-2025 for remediation, and the forecast or actual cost of this work for each pipeline segment.

Response:

a. Scheduled for use is the "go live" date for these models transition from the current risk models to the new probabilistic models. These models are still in development with the vendor. These models will be used to identify threats, risk, and prioritize work plans for storage wells and the gas distribution system.

b. Relative Risk Model is a modeling type which uses industry trends to calculate risk on an asset. The scores are unitless numbers which are used to compare assets within the model. These models use similar data as a probabilistic model but usually require less information and is a less detailed analysis.

c. The relative risk models calculate risk scores to compare assets within the model. The distribution model compares grids of distribution pipe and the storage model compares storage wells. It allows a risk-based prioritization for work planning.

d. The comprehensive information request cannot be adequately shared in the format requested. The Company is willing to schedule a meeting and review the information at one of Consumers Energy's office locations.

   i. The risk model will indicate the riskiest segments and assets which could lead to projects in the future but does not categorize projects and the costs of prospective projects.

Witness: MICHAEL P. GRIFFIN
Date: March 10, 2025

U21806-MNSC-CE-0282
Page **1** of **1**

Question:

2. Regarding Witness Griffin's response to U21806-CE-0080 (question 75) part (b) states "the risk models don't currently calculate mitigation effectiveness." Consumers also did not provide any mitigation effectiveness information in part (f) of this question. Please provide mitigation effectiveness (percent risk reduction) estimates or calculations in Consumers possession for each type of mitigation in Witness Griffin's testimony, at minimum for replacement, repair, and asset relocation. This may include historical estimates of mitigation effectiveness or any other applicable data. Please provide in Excel with supporting calculations and workpapers if applicable, with assumptions and inputs clearly documented and formulas intact (if applicable).

Response:

The risk model is used to identify risk and threats to our pipe segments. It is an aid in project selection and prioritization. The risk models do not calculate a mitigation effectiveness. The results from the inline inspection and post inspection remediation work determines the overall health of that pipe segment and ensures it can operate safely until it is scheduled for reassessment.

The Company focuses on analyzing the health of an asset instead of the mitigation effectiveness. Knowing that the asset is safe for operation is the primary driver for the integrity actions taken on an asset. The risk model calculation will show that the overall risk of that asset due to threats has lowered due to the work performed. Some threats to a gas asset are time dependent so that asset is continuously monitored for risk and assessment compliance dates to ensure safe operation.

Witness: MICHAEL P. GRIFFIN
Date: March 10, 2025

U21806-MNSC-CE-0283
Page **1** of **1**

Question:

3. Witness Griffin's Direct Testimony at page 11 states "Federal Regulation, 49 CFR Part 192, Subpart O, specifies how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the integrity of natural gas transmission pipelines that could, in the event of a leak or failure, affect High Consequence Areas ("HCA")."

a. Does Consumers apply the requirements from 49 CFR part 192 to non-HCA pipelines? Please explain.

b. What PHMSA regulations are applicable to non-HCA pipelines? Please list and explain.

c. Please explain whether Consumers has discretion of when, whether, and how to remediate non-HCA pipelines according to federal regulations.

d. Please explain whether Consumers has discretion of when, whether and how to remediate HCA pipelines according to federal regulations.

Response:

a. Yes, the Company follows the requirements in 49 CFR 192 for segments non-HCA.

b. Regulations contained within 49 CFR 192 outline requirements to design, construct, operate, test, inspect, and maintain pipe segments in HCA and non-HCA areas. Subpart O outlines requirements for an integrity program within HCA segments. One example of additional requirements is to perform inspections on pipe segments considered "Outside of HCA" in 49 CFR 192.710. The segments in the work plan contain a mix of HCA, 49 CFR 192.710 miles, and non-covered pipe. The Company applies the appropriate regulations to the pipe segment to ensure safe operation.

c. The Company must remediate all "HCA" and "Outside of HCA" covered pipe segments per regulation. The Company performs remediation on all non-covered pipelines to ensure safe operation. This work is typically performed within a single outage to optimize efficiency. The Company performs remediation in accordance with 49 CFR 192.933 and 49 CFR 192.714.

d. See response to Part c.

Witness: MICHAEL P. GRIFFIN
Date: March 10, 2025

U21806-MNSC-CE-0284
Page **1** of **3**

Question:

4. Regarding Witness Griffin's response to U21806-CE-0080 (question 75), attachment U21806-MNSC-CE-0080-CONF_ATT_1.

a. Please provide a definition and description of each column header other than column A. This should include, for applicable column headers, how the values are calculated and what units they are in.

b. Please explain why some high-risk pipeline segments are not in an HCA. For example, the first segment, 2800-1, is not in an HCA. Why is this segment so high risk?

c. It appears there is a calculation of residual risk in column K. Does this indicate the amount of risk remaining after a mitigation? If yes, how was the mitigation determined? If not, how is this defined?

d. In Excel, please add the following information to this attachment in separate columns for each pipeline segment where there is forecast work:

   i. Pipeline program where the cost is included (e.g. TIMP, Pipeline Integrity, Capacity/Deliverability etc.);

   ii. Mitigation proposed or forecast (e.g. repair (please specify), replacement, etc.);

   iii. Cost (Estimated or actual).

e. Please explain why Consumers forecasts remediation of pipelines with near-zero risk, such as row 234,131, and some of the least risky pipeline segments above this last pipeline segment row.

f. Please explain whether Consumers prioritizes transmission and TOD segments for inspection (and/or remediation) by total risk or risk per mile. Please explain this choice and provide supporting documentation.

Response:

a. Name: Pipe segment designation
HCA: 0=No, 1=Yes
FromMeasureFT: odometer reading down the pipe where that data set starts. Measured in Feet
ToMeasureFT: odometer reading down the pipe where that data set ends. Measured in Feet
Length_Ft: The physical length of the data set (to – from) measured in feet
Length_miles: The physical length of the data set (to – from) measured in miles
FromForecastYear: The start of the time period of that risk score (Sets the integral time period for the risk analysis. This is a Bayesian statics model)
ToForecastYear: The start of the time period of that risk score (Sets the integral time period for the risk analysis. This is a Bayesian statics model)

RiskTotal_RU_YR: the total risk score for this year. The model calculates a probability and a consequence per threat. That is the risk per threat and then each risk per threat is aggregated into a total risk. This is a unitless score.
RiskTotal_Ru_yr_Actionable: Risk due to threats which can be mitigated via inspection and remediation or an engineering in-ditch replacement project. This is a unitless score.
RiskTotal_Ru_yr_Residual: Risk due to threats which cannot be mitigated. These are environmental risks which cannot be lowered with an inspection, remediation or in-ditch replacement. This is a unitless score.
Risk___External_Corrosion__Ru_yr: Risk value for external corrosion. This is a unitless score.
Risk___Internal_Corrosion__Ru_yr_: Risk value for internal corrosion. This is a unitless score.
Risk___Stress_Corrosion_Cracking__Ru_yr_: Risk value for Stress Corrosion Cracking. This is a unitless score.
Risk___Manufacturing_Defects__Ru_yr_: Risk value for manufacturing defects. This is a unitless score.
Risk___Construction_Defects__Ru_yr_: Risk value for construction defects. This is a unitless score.
Risk___Third_Party___Mechanical_Damage__Ru_yr_: Risk value for third party damage. This is a unitless score.
Risk___Equipment_Failure__Ru_yr_: Risk value for equipment failure. This is a unitless score.
Risk___Incorrect_Operations_Procedure__Ru_yr_: Risk value for incorrect operations. This is a unitless score.
Risk___Weather_Related_and_Outside_Force__Ru_yr_: Risk value for weather related and outside forces. This is a unitless score.

b. Total Risk = Probability of Failure x Consequence of Failure. Some segments have risk driven by probability and other segments by consequence. HCA could indicate a higher consequence of failure but has no impact on the probability of a failure. The first row, 2800-1, the elevated risk score is driven by probability of failure due to threats present and not consequence.

c. The probabilistic models do not calculate a mitigation effectiveness, and this is not a mitigation calculation. The residual risk in column K is calculated by combining the threats: 3rd Party Damage, Weather and Outside Force, and Incorrect Operations. These threats are managed with operational preventative measures.

d. The information from the risk results cannot be organized into the categories suggested in this interrogatory. The risk model analyzes segments of pipelines though dynamic segmentation, so when there is any change in a data property the risk model will perform segmentation for all the data points provided on a given line segment. Thus, the risk model will indicate the riskiest segments which could lead to projects, primarily in Pipeline Integrity or Asset Relocation in the future but does not categorize projects and costs such that they would translate to the capital projects and programs. Further, besides not indicating specific projects, the model does not calculate the cost of prospective projects.

U21806-MNSC-CE-0284
Page **3** of **3**

e. This row is a piece of Dx1087b pipe segment. In this pipe system there are areas which are HCA which requires assessment and those of higher risk score. The model calculates risk scores on the entire transmission system. A row of data does not indicate work or remediation is being performed at that location.

f. The Company prioritizes segments for planning based upon total risk. Risk per mile will over-inflate the prioritization of smaller assets and skew the modeling results. That value is used for generalized mapping and not for work planning. Inspection Segments are ranked by total risk. The threats contributing to the risk score are evaluated to determine the type of inspection and the technology selected to inspect that asset. Additionally federal regulation provides requirements for the timing and methodology of these assessments.

Witness: MICHAEL P. GRIFFIN
Date: March 10, 2025

U21806-MNSC-CE-0285
Page **1** of **1**

Question:

5. Regarding Witness Griffin's response to U21806-CE-0081(question 76):

a. Please explain why Consumers does not consider cost-effectiveness or RSE metrics to evaluate different mitigations for transmission or TOD projects.

b. Please explain why Consumers does not consider cost-effectiveness or RSE metrics to evaluate different mitigations for distribution projects.

c. Please explain whether Consumers believes cost-effectiveness is a relevant criterion for choosing what mitigation to deploy for pipeline remediation, including why or why not.

Response:

a. The Company's current processes prudently address system risk in a cost-effective manner. The probabilistic model is designed to inform the operator of the overall risk of an asset and the threats that are present on that asset. This allows for the selection of the proper method and technology to assess those threats. The results from the inspection and post inspection remediation work determines the overall health of that pipe segment and ensures it can operate safely until it is scheduled for reassessment. The risk model is used to identify risk and threats to our pipe segments. It is an aid in project selection and prioritization. Cost effectiveness is factored into the remediation methodology selected for each individual project as well as complying with all applicable regulations and industry standards.

b. The Company's current processes prudently address system risk in a cost-effective manner. The distribution relative model is designed to inform the operator of the overall risk of the asset and the threats that are present on that asset. This allows for the selection of grid-based projects to address those threats. The risk model is used to identify risk and threats to our pipe segments. It is an aid in project selection and prioritization. Cost effectiveness is factored into the remediation methodology selected for each individual project as well as complying with all applicable regulations and industry standards.

c. The Company inspects the pipe anomalies found during the inspection process. There are multiple permanent repair options available. The Company selects the most appropriate method of remediation based on multiple considerations (i.e. cost effectiveness, operational considerations, system demand, and environmental constraints).

Witness: MICHAEL P. GRIFFIN
Date: March 10, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Historical 13 Month Average of IT Cloud Computing Prepaid Balance
For the years 2023 - 13 months balance ending June 30, 2024
Gas Allocation

Attachment No.: U21806-AG-CE-0852_ATT_2
Page: 1 of 2
Witness: SHBaker
Date: April 2025

Line No.	(a) Description	(b) Bal. Ending 6/30/2023	(c) Bal. Ending 7/31/2023	(d) Bal. Ending 8/31/2023	(e) Bal. Ending 9/30/2023	(f) Bal. Ending 10/31/2023	(g) Bal. Ending 11/30/2023	(h) Bal. Ending 12/31/2023	(i) Bal. Ending 1/31/2024	(j) Bal. Ending 2/29/2024	(k) Bal. Ending 3/31/2024	(l) Bal. Ending 4/30/2024	(m) Bal. Ending 5/31/2024	(n) Bal. Ending 6/30/2024	(o) 13 mos. Average
1	**IT Cloud Computing Prepaid**	$ (4,508,233)	$ (4,265,049)	$ (3,836,559)	$ (3,489,259)	$ (2,822,343)	$ (2,551,776)	$ (2,236,121)	$ (5,664,387)	$ (5,035,475)	$ (5,296,007)	$ (4,860,516)	$ (4,279,397)	$ (3,880,393)	**$ (4,055,809)**
2	**Total**	**$ (4,508,233)**	**$ (4,265,049)**	**$ (3,836,559)**	**$ (3,489,259)**	**$ (2,822,343)**	**$ (2,551,776)**	**$ (2,236,121)**	**$ (5,664,387)**	**$ (5,035,475)**	**$ (5,296,007)**	**$ (4,860,516)**	**$ (4,279,397)**	**$ (3,880,393)**	**$ (4,055,809)**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected 13 Month Average of IT Cloud Computing Prepaid Balance
For the years 2025 - 13 months balance ending October 31, 2026
Gas Allocation

Attachment No.: U21806-AG-CE-0852_ATT_2
Page: 2 of 2
Witness: SHBaker
Date: April 2025

Line No.	(a) Description	(b) Bal. Ending 10/31/2025	(c) Bal. Ending 11/30/2025	(d) Bal. Ending 12/31/2025	(e) Bal. Ending 1/31/2026	(f) Bal. Ending 2/28/2026	(g) Bal. Ending 3/31/2026	(h) Bal. Ending 4/30/2026	(i) Bal. Ending 5/31/2026	(j) Bal. Ending 6/30/2026	(k) Bal. Ending 7/31/2026	(l) Bal. Ending 8/31/2026	(m) Bal. Ending 9/30/2026	(n) Bal. Ending 10/31/2026	(o) 13 mos. Average
1	**IT Cloud Computing Prepaid**	$ 6,274,952	$ 5,341,887	$ 4,420,469	$ 8,600,347	$ 7,727,563	$ 6,831,587	$ 6,960,145	$ 6,123,929	$ 6,143,438	$ 6,789,702	$ 6,076,659	$ 5,610,842	$ 4,812,040	**$ 6,285,659**
2	**Total**	**$ 6,274,952**	**$ 5,341,887**	**$ 4,420,469**	**$ 8,600,347**	**$ 7,727,563**	**$ 6,831,587**	**$ 6,960,145**	**$ 6,123,929**	**$ 6,143,438**	**$ 6,789,702**	**$ 6,076,659**	**$ 5,610,842**	**$ 4,812,040**	**$ 6,285,659**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the distribution of natural gas and for other relief.	)))))	Case No. U-21806

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Melissa K. Harris, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on June 3, 2025, she served an electronic copy of the **Official Exhibits of Consumers Energy Company**, pursuant to the Protective Order in this case, upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Melissa K. Harris

Subscribed and sworn to before me this 3rd day of June, 2025.

Crystal L. Chacon, Notary Public
State of Michigan, County of Eaton
My Commission Expires: 05/25/30
Acting in the County of Jackson

ATTACHMENT 1 TO CASE NO. U-21806

Party	Mailing Address	Email Address
Administrative Law Judge		
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Counsel on behalf of Sierra Club ("SC")		
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* Receives Confidential Materials

ATTACHMENT 1 TO CASE NO. U-21806

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* Receives Confidential Materials